

# NUCLEAR REGULATORY COMMISSION

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Subcommittee on Power Uprates

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 30, 2005

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on November 30, 2005, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

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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

+ + + + +

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

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## 1 NRC STAFF PRESENT:

2 JAMES BONGARRA, NRR

3 ROBERT DAVIS, NRR

4 BARRY ELLIOT, NRR

5 RICK ENNIS, NRR

6 RAY GALLUCI, NRR

7 MICHELLE HART, NRR

8 CORNELIUS HOLDEN, NRR

9 STEVE JONES, NRR

10 KRZYSZTOF PARCZEWSKI, NRR

11 ROGER PEDERSEN, NRR

12 DEVENDER REDDY, NRR

13

## 14 ENTERGY/GE STAFF PRESENT:

15 VINCENT ANDERSON

16 RICO BETTI

17 MICHAEL DICK

18 JIM CALLAGHAN

19 JOHN DREYFUSS

20 JIM FITZPATRICK

21 JERRY HEAD

22 BRIAN HOBBS

23 PAUL JOHNSON

24 CRAIG NICHOLS

25 PEDRO PEREZ

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**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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24 Adjourn

25

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

8:31 A.M.

1  
2  
3 CHAIRMAN DENNING: The meeting will now  
4 come to order. This is a continuation of a meeting of  
5 the Advisory Committee on Reactor Safeguards  
6 Subcommittee on Power Uprates.

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

12 The purpose of this meeting is to discuss  
13 the extended power uprate application for the Vermont  
14 Yankee Nuclear Power Station. The Subcommittee will  
15 hear presentations by and hold discussions with  
16 representatives of the NRC Staff, the Vermont Yankee  
17 licensee, Entergy Nuclear Northeast regarding these  
18 matters.

19 The Subcommittee will gather information,  
20 analyze relevant issues and facts and formulate  
21 proposed positions and actions, as appropriate, for  
22 deliberation by the Full Committee.

23 Ralph Caruso is the Designated Federal  
24 Official for this meeting.

25 The rules for participation in today's

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1 meeting have been announced as part of the notice of  
2 this meeting previously published in the Federal  
3 Register on November 14 and November 28, 2005.

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

10 A transcript of the meeting is being kept  
11 and will be made available as stated in the Federal  
12 Register notice. It is requested that speakers first  
13 identify themselves and speak with sufficient clarity  
14 and volume so that they can be readily heard. It is  
15 especially important today for people to speak up into  
16 the microphones because the meeting is being broadcast  
17 via conference call link. The conference call will  
18 allow stakeholders to listen to the discussion today,  
19 but we will not be taking comments over the phone.

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

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

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

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

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

23 We have a lot of things on the agenda  
24 today I want to brief here. Yesterday, Dr. Denning  
25 requested that we try to fit a presentation into the

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1 agenda sometime today concerning debris loading on the  
2 emergency core cooling system, ECCS, suction  
3 strainers. Entergy and the NRC Staff had some  
4 discussions yesterday afternoon and it was decided  
5 that Entergy would be willing to do that presentation  
6 today. However, due to the short amount of time to  
7 prepare, we request that that will be done some time  
8 after lunch today.

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

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

16 DR. BANERJEE: Three o'clock.

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

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

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1 CHAIRMAN DENNING: As a place to cut back.

2 MR. ENNIS: Cut back.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

17 CHAIRMAN DENNING: Ten and 11, yes.

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

21 CHAIRMAN DENNING: That sounds good.

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

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

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

6 CHAIRMAN DENNING: You can proceed.

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

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

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

22 MR. CALLAGHAN: Good morning. As Mr.  
23 Nichols identified, I'm Jim Callaghan, Design  
24 Engineering Manager Vermont Yankee and this morning  
25 I'll be presenting a short overview of the flow-

1 accelerated corrosion program at Vermont Yankee and  
2 the potential EPU impact. I'll also be giving a very  
3 short presentation on PT curves.

4 Next slide.

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

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

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

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

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

22 MEMBER WALLIS: Proportional to velocity.

23 MR. CALLAGHAN: Yes.

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

1 increase then?

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

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

8 Next slide.

9 Vermont Yankee typically inspects between  
10 25 and 35 large bore components each refueling outage.  
11 This inspection scope is determined by use of the  
12 CHECWORKS tool, past VY inspections, engineering  
13 judgment and industry operating experience.

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

19 MEMBER WALLIS: Where does the material  
20 go?

21 MR. CALLAGHAN: Pardon me?

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

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

1 MEMBER WALLIS: Where does the material  
2 go?

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

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

7 MR. CALLAGHAN: I'm not sure.

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

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

13 MR. LEITCH: Have you had to replace any?

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

20 Additionally, the next three slides --

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

23 MR. CALLAGHAN: Different types. We have  
24 some of the one and a half percent chrome, 2 and a  
25 half percent chrome. In fact, we use stainless steel,

1 too. It's all FAC-resistant material.

2 MR. LEITCH: Is that original?

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

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

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

12 MEMBER KRESS: That helps a lot.

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

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

19 First slide is equipment. We have  
20 replaced all 10 of our feedwater heater shells with  
21 resistant material. We've also done our low pressure  
22 turbine casings. The next page identifies some large  
23 bore piping. The majority of our two-phase flow  
24 piping at Vermont Yankee has been changed out to FAC-  
25 resistant material which keeps our concerns to a

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1 minimum and basically lowers the amount of inspections  
2 we did. We started, we did a number of -- a larger  
3 number of inspections when we first started the  
4 program, based on replacing materials and based on our  
5 results, that's where we've gotten down to the 25 to  
6 35 large bore components right now.

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

11 Next slide.

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

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

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1 the temperature is on the curve.

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

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

14 MR. CALLAGHAN: Mr. Fitzpatrick?

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

24 Typically, from other EPU studies, the  
25 increase in wear rates projected the maximum has been

1 about the proportion of velocity increase.

2 MEMBER RANSOM: Is this built into  
3 CHECWORKS?

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

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

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

23 MR. FITZPATRICK: For the single-phase  
24 systems, it would be -- Jim Fitzpatrick. For the  
25 single-phase systems, it's chemical. The oxide in

1 typical FAC, single-phase FAC, the oxygen in the oxide  
2 goes in solution and iron goes free and the process  
3 keeps repeating itself.

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

6  
7 MR. FITZPATRICK: Yes.

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

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

14 DR. BANERJEE: Also, it just dissolves?

15 MR. FITZPATRICK: It goes --

16 DR. BANERJEE: Without the projective  
17 oxide layer.

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

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

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

25 DR. BANERJEE: Sure.

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

6 DR. BANERJEE: What are your velocities  
7 like?

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

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

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

16 DR. BANERJEE: Okay.

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

1 somewhere in between.

2 MR. FITZPATRICK: Because of the other  
3 factors involved.

4 MEMBER SIEBER: Right.

5 MR. CALLAGHAN: Jim Callaghan.

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

8 MR. CALLAGHAN: Yes, done at refueling  
9 outages.

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

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

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

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

3 MR. LEITCH: It's just carbon steel.

4 MR. CALLAGHAN: Carbon steel. Single-  
5 phase.

6 MR. LEITCH: Which helps.

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

10 MR. CALLAGHAN: I do not believe so.

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

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

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

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

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

22 DR. BANERJEE: So you still have those?

23 MR. NICHOLS: We still have stalite.

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

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1 around the system?

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

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

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

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

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

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

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

21 Next. In conclusion, Vermont Yankee  
22 expects minimal changes in actual FAC-wear rates due  
23 to EPU. This is based on significant amount of the  
24 flow-accelerated corrosion resistant material in  
25 place, minimal wear rates identified through previous

1 inspections and the flow increase from EPU which could  
2 be significant, 25 percent, but based on what we're  
3 seeing already, 25 percent of very little is still  
4 very little.

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

7 MR. CALLAGHAN: In the number of  
8 inspections.

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

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

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

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

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

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

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

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

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

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

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

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

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

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1 specs which is 1.24 times  $10^{18}$  neutrons per centimeter  
2 squared.

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

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

9  
10 MR. CALLAGHAN: Yes.

11 MEMBER WALLIS: Integral through what?

12 CHAIRMAN DENNING: Through plant lifetime.

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

16 MR. CALLAGHAN: Yes, it is.

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

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

24 MR. BETTI: I am Ricco Betti. The  
25 interesting thing about the fluence evaluation that we

1 had done was that our original fluence evaluation and  
2 numbers that we had for designed for our internals was  
3 much higher than those that were calculated in our  
4 updated fluence calc.

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

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

17 MR. BETTI: That's right.

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

22 MR. BETTI: No.

23 CHAIRMAN DENNING: No.

24 MEMBER KRESS: These integrated fluence  
25 values, are they both with the new flux calculations

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1 or is this CLTP, the old one with the old flux?

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

3 -- MEMBER KRESS: Both with the new.

4 MR. BETTI: Flow calc.

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

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

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

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

16 MEMBER KRESS: Is not 26 percent.

17 MR. PEREZ: Right.

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

20 MR. PEREZ: Exactly.

21 MEMBER KRESS: Thirty years at the lower.

22 CHAIRMAN DENNING: Another way to look at  
23 is you're increasing power by 20 percent, so that's  
24 automatically increasing the fluence by 20 percent,  
25 plus you have to flatten the core. And when you

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1 flatten the core you're raising the outer edges which  
2 most influences the vessel wall.

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

5 MR. CALLAGHAN: Any other questions?

6 CHAIRMAN DENNING: No other questions,  
7 thank you.

8 MR. CALLAGHAN: Thank you very much.

9 (Pause.)

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

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

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

23 With respect to surveillance program, the  
24 regulation that is here is the Appendix H, established  
25 rules for -- that all licensees must use and to

1 monitor radiation embrittlement. There are two  
2 choices. You can have a plant-specific program where  
3 the capsules are irradiated within the existing  
4 vessel, or you can have an integrated surveillance  
5 program where it could be a host reactor providing  
6 data to the plant.

7 In this case, for Vermont Yankee, they're  
8 part of an integrated surveillance program which is  
9 used for the entire BWR fleet. This program was  
10 approved for Vermont Yankee in a letter dated March  
11 29, 2004. In this program, the monitoring of the weld  
12 and the plate material will be used -- that Vermont  
13 Yankee will use the data from the Susquehanna Unit One  
14 Surveillance Program.

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

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

23 MR. ELLIOT: The integrated surveillance  
24 program was established many years ago for the BWR  
25 fleet. Some plants were missing data and some plants

1 didn't have good data. So they decided to use an  
2 integrated approach where they would look for, at each  
3 vessel and look throughout the entire fleet  
4 surveillance program and pick out particular capsules  
5 that would be used for each vessel. It turned out  
6 that the Susquehanna surveillance material was very  
7 good for Vermont Yankee. So that's how we wound up  
8 there.

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

12 MR. ELLIOT: That's right.

13 CHAIRMAN DENNING: So welding materials  
14 were similar?

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

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

22 MR. ELLIOT: Susquehanna has a higher leaf  
23 factor.

24 MEMBER SIEBER: That's true.

25 MR. ELLIOT: And so they get more

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

4 MEMBER SIEBER: Have they caught up yet?

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

7 MEMBER SIEBER: It's sort of a race.

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

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

14 MR. ELLIOT: Yes. And --

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

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

25 The second issue that we address in vessel

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

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

24 The same thing with the pressure  
25 temperature limits. I don't want to redo what was

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1 just done a minute ago, but they're very low copper.  
2 It's plate limited because the copper is so low, so  
3 this vessel, the PT limits can last a very long time.

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

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

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

22 For uprate conditions, the only internal  
23 component that will receive this type of fluence is  
24 the top guide grid beams. In response to a Staff RAI,  
25 the licensee has adjusted its top guide grid beam

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1 program and it's now, we'll be doing periodic  
2 inspection of the top guide grid beams and that's  
3 where we're at. They will start that after they start  
4 power uprate.

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

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

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

24 Thank you.

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

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

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

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

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

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

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

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1 A material per NUREG 0313 which is a low carbon 316  
2 stainless steel which is resistant to intergranular  
3 stress corrosion cracking.

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

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

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

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

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

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

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

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

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

24 The flow-accelerated corrosion, I've  
25 prepared a presentation, is limited to the amount of

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1 material provided to us in our submittal. You heard  
2 presentation with quite a bit of presentation of the  
3 material on the flow-accelerated corrosion. So to  
4 listen to my presentation is basically repetition of  
5 what has been presented before.

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

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

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

22 The effect of EPU organic material was  
23 assessed by the test, performed by Argon Research  
24 Laboratory. They simulated the LOCA environment and  
25 found the strained approach velocity and suppression

1 turbulence were very, very low and did not change  
2 after EPU. There was no change in NPSH therefore.

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

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

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

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

16 MR. PARCZEWSKI: I'm sorry?

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

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

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

25 MR. PARCZEWSKI: Very, very few of them

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

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

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

8 MR. PARCZEWSKI: The turbulence level is  
9 very low.

10 MEMBER WALLIS: But that is an assumption.

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

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

20 DR. BANERJEE: What is the sludge  
21 material?

22 MR. PARCZEWSKI: Beg pardon?

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

25 MR. PARCZEWSKI: It's usually aquatic

1 different materials.

2 DR. BANERJEE: How does that arise?

3 MR. PARCZEWSKI: It is corrosion products.

4 DR. BANERJEE: >From where?

5 MR. PARCZEWSKI: >From the piping.

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

11 MR. PARCZEWSKI: Well --

12 DR. BANERJEE: Is it going to go up?

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

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

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

20 MR. ELLIOT: Excuse me --

21 DR. BANERJEE: You clean it out --

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

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

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

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

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

17                   MR. PARCZEWSKI: Yes.

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

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

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

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

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

7 Is that acceptable?

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

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

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

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

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

3 MR. CARUSO: That was not your internet?

4 MR. ELLIOT: No.

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

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

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

16 MR. PARCZEWSKI: No.

17 MEMBER KRESS: That's only PWRs?

18 MR. PARCZEWSKI: Yes.

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

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

23 CHAIRMAN DENNING: Go ahead.

24 MR. PARCZEWSKI: The rates of flow-  
25 accelerated corrosion are affected, but several

1 operational parameters some of which will be -- will  
2 change after EPU. These parameters are flow velocity,  
3 temperature, moisture and oxygen content.

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

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

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

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

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

25 Flows with the system, usually within .8

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

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

6 MR. PARCZEWSKI: Yes, it does increase.

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

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

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

22 In addition, the licensee verified for all  
23 pipes and components, the pressure and temperature  
24 rating will remain unaffected because of negligible  
25 changes in system process parameters and no

1 instrumentation set forth needs to be adjusted. So  
2 basically the changes are very small after EPU.

3 DR. BANERJEE: Can I ask you a question?

4 MR. PARCZEWSKI: Yes.

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

10 MR. PARCZEWSKI: Yes.

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

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

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

19 CHAIRMAN DENNING: Why is that, Sanjoy?

20 DR. BANERJEE: More power is being  
21 generated.

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

25 DR. BANERJEE: The quality of everything

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

5 MEMBER WALLIS: It depends on where the  
6 break is.

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

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

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

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

21 DR. BANERJEE: They subscribe to this  
22 conclusion.

23 MR. ENNIS: I think Michael Dick from --

24 MR. DICK: This is Michael Dick with GE.  
25 The answer isn't, and part of the beauty of the

1 constant pressure power uprate is is that there is  
2 either no effect or very minimal effect. I can give  
3 you a couple of examples.

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

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

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

23 MEMBER KRESS: Just lasts longer.

24 MR. DICK: Yes, yes.

25 MEMBER KRESS: But by the time you get

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

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

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

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

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

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

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

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

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1 intense is of the same magnitude.

2 MR. DICK: Sure, sure.

3 DR. BANERJEE: That's the argument.

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

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

17 MR. DICK: Sure.

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

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

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

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

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

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

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

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

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

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

1 MEMBER WALLIS: I have a question.

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

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

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

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

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

9           MEMBER WALLIS: So there's no vibration  
10          problem?

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

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

16          MR. DICK: Yes.

17          MEMBER WALLIS: No shaking.

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

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

1 MR. DICK: This is Michael Dick with GE  
2 again. Vermont Yankee has both hydrogen water --  
3 they're what we call a low hydrogen injection plant  
4 because they have both hydrogen water chemistry and  
5 Nubble metal coating, so effectively, the rate of  
6 hydrogen injection will increase with the proportional  
7 to the feedwater flow rate in order to maintain the  
8 same PPM concentration of hydrogen in the feedwater  
9 system, okay, which of course goes through the vessel.  
10 So yes, there is a very, very slight -- well,  
11 effectively, there's a 20 percent or 22 percent  
12 increase in hydrogen consumption and I don't have the  
13 actual VY's injection levels, but for low hydrogen  
14 injection plants, that injection rate is a factor of  
15 10 to 20 lower than the systems were originally  
16 designed and analyzed to be able to inject and not  
17 have problems with normal operational doses in the  
18 plants.

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

21 MR. DICK: Oh absolutely. That's  
22 something -- I believe that is -- and once again, I  
23 plead a little bit of ignorance. I don't have the  
24 exact VY value they're injecting now, but typically  
25 that would be on the order of say 1 to 2 SCFM and so

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1 then it would go up 20 percent. So effectively going  
2 from 2 to 2.2 SCFM. That's a very, very low hydrogen  
3 injection rate.

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

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

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

18 MEMBER SIEBER: All right.

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

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

23 MR. DICK: No sir.

24 MEMBER KRESS: It's not --

25 MR. DICK: Yeah, that would have only

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

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

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

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

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

11              DR. BANERJEE:   Right.

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

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

16              MR. DICK:       Yes sir.

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

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

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

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

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

5 MR. DICK: Yes sir.

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

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

12 DR. BANERJEE: All right.

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

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

25 MEMBER WALLIS: Is it already there?

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

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

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

12 MR. NICHOLS: We can do that.

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

15 (Pause.)

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

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

19 CHAIRMAN DENNING: Yes.

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

24 Station blackout is referred to as the  
25 loss of all off-site power to the Vermont Yankee

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

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

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

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

19 A coping study that's performed includes  
20 reactor level control using our high pressure coolant  
21 injection system, reactor pressure control with a  
22 safety relief valve. It's been determined that there  
23 is sufficient inventory in the condensate storage  
24 tank, that the battery capacity is sufficient for that  
25 two-hour period until the battery chargers can be

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1 realigned after the restoration of AC power.

2 The peak torus temperature remains below  
3 185 degrees during the whole of the event, meaning  
4 there's no need for credit and containment over  
5 pressure for NPSH. The loss of ventilation for the  
6 control room and the emergency core cooling systems  
7 has been evaluated and that there is sufficient air or  
8 in our case, nitrogen, available for operating the  
9 SRVs and necessary loads.

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

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

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

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1 MR. NICHOLS: That's correct.

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

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

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

10 CHAIRMAN DENNING: Yes, and now if you  
11 continued that forever and you've got no more AC power  
12 back, would the torus temperature then rise above the  
13 185?

14 MR. NICHOLS: No.

15 CHAIRMAN DENNING: No?

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

18 CHAIRMAN DENNING: Peaks that early?

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

21 MR. NICHOLS: That's correct.

22 MEMBER SIEBER: Either one.

23 MR. NICHOLS: Right.

24 CHAIRMAN DENNING: What I'm trying to  
25 figure out is what's the difference between that and

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1 the LOCA as far as where the heat is going? Where is  
2 the heat going?

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

5 CHAIRMAN DENNING: Yes.

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

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

11 MR. RAINEY: Not right at the beginning.

12 MEMBER WALLIS: So eventually it has to go  
13 somewhere.

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

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

19 CHAIRMAN DENNING: Uh-huh.

20 MEMBER WALLIS: Can you start the plant  
21 based on just the verson supply?

22 MR. NICHOLS: No.

23 MEMBER WALLIS: You need to have the --

24 MEMBER SIEBER: The tech specs would --

25 MR. NICHOLS: We'd be fed by the off-site

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1 power supply and have to have the diesel generators  
2 available.

3 MEMBER SIEBER: Two alternate sources.

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

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

9 CHAIRMAN DENNING: That are not in there.

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

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

14 MEMBER WALLIS: It's a realistic  
15 calculation.

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

22 MEMBER WALLIS: But there's nobody there.

23 MR. NICHOLS: Right.

24 MEMBER WALLIS: They're notifying Wilder  
25 or something.

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

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

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

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

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

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

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

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

1 contract within 90 minutes.

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

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

6 So once the vernon hydro is started, the  
7 orders are given to realign the power and provide the  
8 4 kV power from that station to the Vermont Yankee  
9 emergency bus.

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

12 MR. NICHOLS: That's correct.

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

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

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

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

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

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

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

13 MEMBER SIEBER: Right.

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

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

21 CHAIRMAN DENNING: Okay. I understand.

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

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

4 MEMBER SIEBER: Enough to bring a turbine  
5 down.

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

9 MEMBER SIEBER: Okay.

10 MR. NICHOLS: The conclusion for the  
11 Vermont Yankee station blackout at EPU conditions is  
12 that the Vernon hydrostation will be available within  
13 the 2-hour period which meets the criteria for the 2-  
14 hour AAC that the station blackout coping period of 2  
15 hours is satisfied, given the parameters for the plant  
16 and the capabilities that remain in the plant. And  
17 that the plant remains in a safe condition during that  
18 2-hour period and the full 8-hour required station  
19 blackout period.

20 CHAIRMAN DENNING: Now as far as the 2-  
21 hour period is concerned, it looks to me like, as you  
22 pointed out, there just is very little difference in  
23 demand. As you get into the 8-hour period, is there  
24 a significant difference or is it really, as Jack was  
25 saying, it's almost the matter that you're refeeding

1 the charger to the batteries. Do you have significant  
2 additional things that AC power is required for in  
3 that 2 to 8-hour period than the 0 to 2-hour period in  
4 the 2 to 8-hour period?

5 MR. NICHOLS: For the AC power?

6 CHAIRMAN DENNING: Yes.

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

9 CHAIRMAN DENNING: Yes, okay.

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

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

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

24 CHAIRMAN DENNING: Yes, gotcha.

25 MEMBER WALLIS: This Vernon tie is

1 underground, is it?

2 MR. NICHOLS: The feed from the Vernon tie

3 --

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

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

8 MEMBER WALLIS: It's above ground now?

9 MR. NICHOLS: The transformer is.

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

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

18 MEMBER WALLIS: All enclosed.

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

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

24 MR. JOHNSON: That's correct.

25 CHAIRMAN DENNING: And the important thing

1 is also they're not affected by EPU. I mean this is  
2 a question that's already been resolved as far as the  
3 NRC is concerned.

4 MR. NICHOLS: That's correct.

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

7 CHAIRMAN DENNING: Almost.

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

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

12 MR. NICHOLS: That is correct.

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

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

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

22 MR. NICHOLS: Yes.

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

25 MR. NICHOLS: That is correct.

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

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

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

7 MR. JOHNSON: 1965.

8 MEMBER WALLIS: As long ago as that?

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

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

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

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

18 CHAIRMAN DENNING: Go ahead.

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

25 This morning we want to talk to you about

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

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

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

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

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

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

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

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

24           The reactor engineering group, it's worth  
25 noting, routinely trains with Operations Department

1 for significant events such as startup and plant  
2 shutdowns, other testing related to reactivity. So we  
3 have a good working relationship with them. We also  
4 have a reactor engineer on call 24 hours a day,  
5 specific point of contact. In case something were to  
6 occur during off hours, we have that protocol  
7 established.

8 MR. LEITCH: Do they have their own --

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

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

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

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

23 MR. DREYFUSS: I can. John Dreyfuss,  
24 Director of Engineering. The qualification for  
25 reactor engineering is a position-specific

1 qualification in our engineering training program.  
2 One of the key aspects of that qualification, besides  
3 all of the specific tasks that the individuals have to  
4 perform -- operating the transverse in-core probe  
5 system, other typical reactor engineering functions at  
6 a BWR. They also do go through the General Electric  
7 station nuclear engineering course as well.

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

12 MR. DREYFUSS: That's correct.

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

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

22 MR. WAMSER: We emphasize, you know, the  
23 full qualification for all personnel onsite doing  
24 anything. Engineering programs have specific  
25 qualifications for all of the various engineering

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1 tasks that fall under their areas, similar to the way  
2 Operations has training programs that require  
3 qualifications before we can go out and operate the  
4 plant appropriate to a specific position.

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

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

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

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

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

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

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

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

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

22 MR. HEAD: Yes. I'm Jerry Head, Manager  
23 of Nuclear Engineering Analysis. As I discussed some  
24 yesterday, part of what you're hitting on is correct  
25 in that it's possible to get a power update core

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1 design that is more difficult to manage from the  
2 standpoint of reactor engineering as far as thermal  
3 limits and things like that.

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

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

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

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1 not live with.

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

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

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

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

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

1 MR. WAMSER: That's correct.

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

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

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

25 MEMBER SIEBER: What criteria do you use

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

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

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

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

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

22 MEMBER SIEBER: But you don't --

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

25 MEMBER SIEBER: -- typically coast down.

1 MR. WAMSER: I would say typically we do.

2 MR. HEAD: Typically we do.

3 MEMBER SIEBER: Okay. So you're --

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

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

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

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

20 MEMBER SIEBER: Right.

21 MR. HEAD: And so we carried excess  
22 reactivity over that we had to deal with from -- it  
23 bid us some shutdown margin areas. We ended up with,  
24 you know, excess reactivity that we had to deal with,  
25 and the peaking that you get from that as well. So

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1 it's a -- one of those things you have to balance in  
2 the design process.

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

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

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

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

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1 operator's job.

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

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

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

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

20 MR. WAMSER: Say again.

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

23 MR. WAMSER: No.

24 MR. NICHOLS: We are not.

25 CHAIRMAN DENNING: Continue.

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

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

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

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

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

11                 MR. WAMSER: That's correct.

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

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

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

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

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1 concurrently with that.

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

3 MR. WAMSER: It's always the bravo.

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

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

9 MR. LEITCH: Okay.

10 MR. WAMSER: Sequential, right.

11 MR. LEITCH: Sequential, yes.

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

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

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

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

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1 the new trip.

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

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

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

10 MR. WAMSER: Right.

11 MEMBER SIEBER: Okay.

12 MR. WAMSER: Next slide, please.

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

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

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

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

10          MR. WAMSER: That's correct.

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

13          MR. WAMSER: That's correct.

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

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

17          MR. LEITCH: So it's all --

18          MR. WAMSER: It's all there.

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

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

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

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

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

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

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

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

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

19 MR. WAMSER: That's correct.

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

24 MR. WAMSER: I anticipate all operating  
25 crews are going to be trained. All operating crews

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

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

20 MR. LEITCH: Reactor SCRAM, yes. Thanks.

21 MR. WAMSER: Next, please.

22 In the area of operating procedures,  
23 essentially abnormal and emergency operating  
24 procedures, some items to discuss. Between the  
25 setpoint changes and some hardware changes associated

1 with the EPU, there have been changes made to several  
2 abnormal operating procedures.

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

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

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

22 MR. WAMSER: Absolutely. And --

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

25 MR. WAMSER: Absolutely. And the timeline

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

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

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

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

21 MR. WAMSER: That is certainly true.

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

24 MR. WAMSER: That is true. Absolutely.

25 MEMBER SIEBER: And so the operators

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1 are --

2 MR. WAMSER: Why don't we --

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

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

8 MEMBER SIEBER: All right.

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

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

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

21 MR. WAMSER: Say again.

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

24 MR. WAMSER: That is correct. And in that  
25 area, Operations and Training has received information

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1 from PSA Group on time-critical steps and has reviewed  
2 that. And, essentially, what we determined was  
3 anything that was required to occur within 30 minutes  
4 warranted our review.

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

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

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

25 MEMBER SIEBER: Well, you know, the

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

6 And with everything happening faster --

7 MR. WAMSER: Well --

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

10 MR. WAMSER: -- you're absolutely right.

11 And this comes to the core of, how do we perform  
12 training? How do we determine what is the appropriate  
13 thing to train on? How frequently do we train on it,  
14 and how do we emphasize it? And what you're  
15 describing is something that has a significant issue.

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

23 MEMBER SIEBER: And you feel confident  
24 that it does?

25 MR. WAMSER: I am absolutely confident.

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

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

13 MEMBER SIEBER: Yes.

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

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

19 MR. WAMSER: That's correct.

20 CHAIRMAN DENNING: Okay. I think we --

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

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

24 MEMBER SIEBER: Who's got the key?

25 MR. LEITCH: I know that in the simulator

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1 usually the keys are in the switches.

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

4 MR. LEITCH: The key is in the switch?

5 MR. WAMSER: Absolutely.

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

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

10 (Laughter.)

11 MR. WAMSER: We know it's important.

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

20 MR. WAMSER: Yes. We have clear -- and  
21 similar to the discussion on ATWS, containment  
22 pressure and accident mitigation essentially, you  
23 know, let's face it, any accident, any break, feed  
24 line, steam line, reactor vessel, recirc loop, you  
25 know, we see that in containment parameters. So it is

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1 another area that we practice routinely in the  
2 simulator managing and mitigating accidents and  
3 transients related to leaks inside containment.

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

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

20 In the area of containment pressure and  
21 net positive suction head for the ECCS pumps, we do  
22 have guidance in the operating procedures that would  
23 say any leg that would require me to depressurize or  
24 reduce containment pressure, i.e. spray of the drywall  
25 and/or torres, would direct me to look at what

1 containment pressure is, what is the temperature in  
2 the torres, what are the net positive suction head  
3 requirements for that pump, and make a determination  
4 of, number one, whether I do it or not, but also how  
5 far do I go before I terminate sprays.

6 MR. LEITCH: Okay.

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

9 MR. LEITCH: Okay. Thank you.

10 CHAIRMAN DENNING: Okay. Thank you, all.

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

13 MR. WAMSER: Okay. Thank you.

14 MEMBER SIEBER: Thank you.

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

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

25 MR. BONGARRA: It becomes more and more

1 difficult as we go on, it seems.

2 (Laughter.)

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

5 (Laughter.)

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

8 MEMBER SIEBER: There you go. Perfect.

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

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

22 CHAIRMAN DENNING: Let's try to focus on  
23 your evaluation of, like, the time -- you know, the  
24 assessment of there are clearly reductions in time.  
25 How did you determine that those reductions in time

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1 really were still -- reduced amounts of time for  
2 performing activities was still adequate?

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

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

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

25 Now, with regard to the actions that were

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

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

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

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

23 MEMBER WALLIS: I would think that's why  
24 you got into the psychology part of it. Actually  
25 doing something may be the easiest part of the whole

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1 action, but figuring out that you're sure that's what  
2 you need to do may take you longer.

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

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

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

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

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

23 So what I'm simply saying here from my  
24 understanding of this event, we're not looking at,  
25 number one, a new event. We're looking at basically

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1 an event that has been, as a routine process within  
2 EOP training, an event that would be trained on as a  
3 -- in a routine fashion.

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

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

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

17 (Laughter.)

18 MR. BONGARRA: I would say "whoops."

19 (Laughter.)

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

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

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

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

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

24 I look at the full core display, are my  
25 control rods moving or not. I look at my APRMs, my

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1 power range monitors, have they moved off of 100  
2 percent, have they gone down scale or not. Tells me  
3 whether the SCRAM was successful or not.

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

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

10 MR. WAMSER: Yes.

11 MEMBER SIEBER: Yes, right. Five seconds  
12 maybe.

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

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

25 We have an automatic setdown on reactor

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

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

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

18 So at that point --

19 MEMBER SIEBER: And these are your  
20 memorized steps.

21 MR. WAMSER: That's correct.

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

25 CHAIRMAN DENNING: Is it correct that this

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

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

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

7 MR. WAMSER: It's the 5.4 minutes.

8 CHAIRMAN DENNING: Is that --

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

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

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

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

23 MR. WAMSER: That's correct. I don't have  
24 the exact details of that specific timeline, but, in  
25 general, what taking that action is doing is to ensure

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1 that the system does not automatically open the safety  
2 relief valves and depressurize their reactor.

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

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

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

22 MR. WAMSER: Yes.

23 MEMBER WALLIS: This is 5.4 minutes from  
24 time zero?

25 MEMBER SIEBER: Yes.

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1 MEMBER WALLIS: So he's doing other things  
2 during those 5.4 minutes. He doesn't have all of the  
3 5.4 minutes to worry about this 1.5-minute action.  
4 He's doing other things, which are stacking up, isn't  
5 he?

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

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

15 MEMBER SIEBER: No, from time zero.

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

18 MEMBER SIEBER: No.

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

21 MEMBER SIEBER: No, not really. Not  
22 really.

23 MR. WAMSER: It is the first --

24 MEMBER SIEBER: That's not what he said.

25 MR. WAMSER: -- action that is directed.

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

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

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

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

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

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

1 DR. BANERJEE: Okay. Thank you.

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

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

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

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

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

25 MEMBER WALLIS: It's not really the main

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

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

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

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

10 (Laughter.)

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

18 The worst case scenario, so to speak, the  
19 most challenging scenario for the containment, is that  
20 they do. And for that we have to have prompt operator  
21 action to get SLC going. If -- you know, essentially  
22 if you consider the fact that if I had a failure to  
23 SCRAM event, and the main condenser stays available as  
24 a heat sink, if the plant, for example, were to settle  
25 out at 20 percent power, I have 20 percent power going

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1 to the main condenser, I have a circ water system  
2 removing the heat from that, and I have more time  
3 available to mitigate that accident.

4 MEMBER SIEBER: You could do that forever.

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

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

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

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

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1 MR. WAMSER: Yes.

2 CHAIRMAN DENNING: Okay.

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

6 MR. WAMSER: Yes.

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

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

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

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

20 MR. WAMSER: Yes. Yes. The emergency  
21 operating procedures flowcharts are decision trees.  
22 And I mentioned in my discussion earlier that  
23 monitoring of all of the various plant parameters is  
24 required, reporting of those plant parameters is  
25 required, and that information has to be processed to

1 determine, in some cases, what is the -- what is the  
2 priority for the operating crew to mitigate an  
3 accident.

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

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

11 MR. WAMSER: That's correct.

12 DR. BANERJEE: There are outcomes  
13 associated with that.

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

22 DR. BANERJEE: Sure. I mean --

23 MR. WAMSER: They put you on a different  
24 path to outcome. Simply stated, a transient or an  
25 accident that requires an operator to use a high

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1 pressure source of injection, and if he is  
2 unsuccessful doing that, essentially if he doesn't  
3 know how to operate, for example, the outcome could be  
4 that the crew depressurizes the plant and uses low  
5 pressure injection.

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

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

14 MR. WAMSER: They are definitely symptom-  
15 based.

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

25 For example, when you discuss in this the

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

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

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

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

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

24 And one of the areas, of course, is human  
25 system interfaces, controls, alarms, and displays, and

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1 essentially in their application for power uprate, the  
2 request for power uprate, they told us that --  
3 essentially that the EPU will affect these particular  
4 items, indicators, main steam line flow indicators,  
5 feedwater flow, etcetera, and they committed,  
6 basically, to make modifications to the  
7 instrumentation.

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

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

23 Are there any potential problems here with  
24 -- that require additional human factors review, or is  
25 it just a matter you're going to change indications on

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1 these displays and stuff?

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

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

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

21 CHAIRMAN DENNING: Is this consistent with  
22 your current --

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

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1 installation.

2 CHAIRMAN DENNING: Right. Proceed.

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

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

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

20 Next slide has to do with operator  
21 training program and the control room simulator.  
22 Again, I think that Entergy did a very thorough job in  
23 describing this earlier. I won't go over all of the  
24 items on this slide, but let me just emphasize the  
25 fact, too, that one of the commitments we look for in

1 our review is the fact that ANSI Standard 3.5, which  
2 is Nuclear Powerplant Simulators for Use in Operator  
3 Training and Examination, is used essentially to make  
4 sure that the simulator changes are made in accordance  
5 with essentially the guidance in that standard.

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

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

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

24 CHAIRMAN DENNING: Okay. Any questions?

25 MEMBER WALLIS: Yes, I have a question.

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1 CHAIRMAN DENNING: Go ahead.

2 MEMBER WALLIS: Regarding the probability  
3 of error --

4 MR. BONGARRA: The probability of error,  
5 sir?

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

13 Did you look at those, and are they  
14 credible?

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

19 MEMBER WALLIS: You didn't look at those?

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

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

24 MEMBER WALLIS: He will answer that? The  
25 thing that surprised me in some of the tables -- and,

1 again, this seems to be labeled proprietary, so I  
2 don't think I can give you any numbers or anything --

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

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

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

10 MEMBER WALLIS: Well, this is CG NEDC-  
11 3309-DP.

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

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

18 MEMBER WALLIS: So it's not proprietary?

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

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

25 CHAIRMAN DENNING: Marty is back here in

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

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

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

9 MEMBER WALLIS: He is going to face that  
10 question.

11 CHAIRMAN DENNING: Yes.

12 MEMBER WALLIS: Okay. Thank you.

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

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

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

24 The NRC staff focused its review efforts  
25 on auxiliary systems which include spent fuel pool

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1 cooling system, service water and ultimate heat sink,  
2 auxiliary cooling system, and condensate and feedwater  
3 system.

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

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

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

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

23 MR. REDDY: Yes.

24 CHAIRMAN DENNING: And the -- when you say  
25 "administrative controls," does that mean that they

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1 have to move fuel out of the pool into dry storage to  
2 be able to do this? Where does the administrative  
3 control --

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

10 And for the power uprate, actually the  
11 gates will be closed after seven and a half days, in  
12 order to maintain the pool temperature 150 -- below  
13 150 degrees. Whereas for the full core offload, the  
14 administrative control will be -- the gates will be  
15 closed after 11 days.

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

25 CHAIRMAN DENNING: Thank you.

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1 MR. REDDY: Next slide.

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

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

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

21 As I mentioned earlier, if service water  
22 system becomes unavailable due to failure of the one  
23 due to fire or flooding in the intake structure, the  
24 alternate cooling system will be relied upon for  
25 supplying the cooling water to the essential

1 components for safe shutdown.

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

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

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

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

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

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

1 tower basin.

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

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

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

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

25 In summary, the staff finds the proposed

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

6 So this --

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

14 MR. REDDY: Well --

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

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

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

1 MR. REDDY: Yes.

2 CHAIRMAN DENNING: That's the safety  
3 issue.

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

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

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

9 CHAIRMAN DENNING: Yes.

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

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

1 the commitment?

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

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

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

14 CHAIRMAN DENNING: Yes.

15 MR. JONES: As a test.

16 CHAIRMAN DENNING: As a test.

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

19 CHAIRMAN DENNING: Okay. But with regards  
20 to the condensate pump, if it fails, then what are the  
21 implications? Do they then have to do some changes to  
22 the way they do their runback? I think when we  
23 discussed this in Vermont there was some indication  
24 that, if it did fail, that there could be changes in  
25 the procedure made in the way they do the runback, and

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1 that, you know, they could then demonstrate that --  
2 with the new change that they would be able to do it.

3 Do you want to make a comment on that?

4 MR. NICHOLS: Yes, just one clarification.

5 For the --

6 CHAIRMAN DENNING: State your name,  
7 please.

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

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

20 CHAIRMAN DENNING: Okay. Continue.

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

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

4 (No response.)

5 Then, go ahead with the fire protection.

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

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

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

24 Regarding the evaluation of the fire  
25 protection, the NRC staff verified that the licensee

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1 examined the five elements of fire protection program,  
2 demonstrating no effect on any of these five elements.

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

10 Next one.

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

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

23 CHAIRMAN DENNING: This may be a question  
24 for Ray.

25 MR. REDDY: Sure.

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

7 MR. REDDY: Ray is there.

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

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

18 CHAIRMAN DENNING: Thank you.

19 MR. REDDY: Do you have other questions.

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

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

7                   MR. REDDY: RHR service water --

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

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

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

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

20                  MR. JONES: Yes.

21                  MEMBER SIEBER: Okay.

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

24                  MEMBER SIEBER: Yes.

25                  CHAIRMAN DENNING: Yes.

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

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

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

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

13 CHAIRMAN DENNING: Thank you.

14 MR. NICHOLS: -- at Vermont Yankee.

15 CHAIRMAN DENNING: Thank you.

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

20 CHAIRMAN DENNING: Okay.

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

23 MEMBER SIEBER: No.

24 CHAIRMAN DENNING: Okay.

25 MR. REDDY: Thank you very much.

1 CHAIRMAN DENNING: Thank you very much.  
2 I think we are done, then, for this  
3 morning. Right?

4 Okay. We will now go in recess until  
5 12:45.

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

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

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

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

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

25 14. PLANT SYSTEMS

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

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

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

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

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

23 The topics we're going to touch on today  
24 are the residual heat removal and core spray suction  
25 strainer arrangement. I'll give you a depiction of

1 what our strainers look like at Vermont Yankee, a  
2 little talk about the stacked disc strainer design.

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

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

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

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

25 MEMBER WALLIS: The core spray outlet is

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1 at one end of that thing?

2 MR. BETTI: That's right.

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

6 MR. BETTI: Yes. We'll --

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

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

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

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1 bend. And we have another section of the strainer.

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

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

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

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

25 The other idea of these kinds of strainers

1 is that you're going to have a big area around these  
2 stacked discs. And as these initially start filling  
3 up with new car, and you end up with the geometry  
4 that's a pretty large area.

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

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

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

22 We made it a difference because we wanted  
23 to assure that we have some tolerance in the design  
24 versus the actual water levels. That was to take into  
25 account any kind of construction or problems that we

1 had during installation. So these design values --  
2 and Bruce will talk to that in a little bit -- are  
3 quite a bit lower than our post-LOCA minimum water  
4 level.

5 Okay, Brian. What you see here is the  
6 core spray suction strainer. I think that was a  
7 14-inch, but it's got an elbow reducer up to the 24,  
8 comes into the same kind of design.

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

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

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

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

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

6 MEMBER WALLIS: Right.

7 MR. BETTI: And then the --

8 MEMBER WALLIS: So it's OD?

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

11 MEMBER WALLIS: Right.

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

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

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

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

23 DR. BANERJEE: Just show the diagram,  
24 please.

25 MEMBER WALLIS: Between 24 and 26. What

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1 is there there?

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

6 MEMBER SIEBER: There's water.

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

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

11 MR. BETTI: That's right.

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

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

18 DR. BANERJEE: Maybe a better diagram.

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

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

23 MR. BETTI: If we're looking at a section  
24 of the -- this outer ring of the torus, which is made  
25 up of these cylindrical discs that are all welded, all

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1 this area is made out of perforated plate, eight-inch  
2 holes, 40 percent open flow area.

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

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

6 MEMBER WALLIS: There are some structural  
7 braces in here.

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

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

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

14 MEMBER WALLIS: Okay.

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

21 So debris collects out here like this.

22 MEMBER WALLIS: Right.

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

25 MR. CARUSO: And where's the center line

1 of that?

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

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

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

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

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

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

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

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

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

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

25 MR. BETTI: Right. This is a PCI patented

1 design strainer. This is design-tested at EPRI when  
2 we bought these rights.

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

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

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

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

25 MEMBER RANSOM: Is this also designed so

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

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

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

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

9 MR. BETTI: Yes, the next slide.

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

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

13 So these are the maximum design flow  
14 velocities that we used in the strainer design for  
15 short-term and long-term post-LOCA conditions. What  
16 you see here is the strainer flow, then the strainer  
17 area, the approach velocity of these strainers based  
18 on their perforated plate area, which we just  
19 described, and then the approach velocity based on  
20 area and approach velocity based on the circumscribed  
21 area of these strainers.

22 Now, these are the inputs that we use into  
23 the program evaluations we use for debris head losses,  
24 these --

25 DR. BANERJEE: I have a question here,

1 maybe for clarification. The circumscribed area, does  
2 that include the thickness of the plates or does it  
3 not? That's the first question.

4 MR. BETTI: Yes, it does.

5 DR. BANERJEE: But there is no flow  
6 through that outer or is there a flow through it? Are  
7 there holes --

8 MR. BETTI: Yes, there is.

9 DR. BANERJEE: -- at the top of the plate  
10 as well?

11 MR. BETTI: There are.

12 DR. BANERJEE: There are holes everywhere?

13 MR. BETTI: Holes everywhere.

14 MEMBER WALLIS: There's much less flow  
15 through that than there is through the gap.

16 DR. BANERJEE: Right, right. So, in fact,  
17 there are holes everywhere.

18 MR. BETTI: That's right. There are holes  
19 everywhere, right.

20 DR. BANERJEE: Okay. The second question  
21 is when you talk about the approach velocity, that is  
22 not the approach velocity into the gap, right?

23 MR. BETTI: Right.

24 DR. BANERJEE: But it is approach velocity  
25 normal to the gap.

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1 MR. BETTI: That's true.

2 DR. BANERJEE: So what is the significance  
3 of that approach velocity when it comes to entrainment  
4 and transport to the strainer because when you talk  
5 about the approach velocity being 0.039, that's not  
6 significant to what is coming to the strainer? The  
7 approach velocity really is .111 or .058 depending on  
8 how much strainers you have.

9 From the viewpoint of turbulence in the  
10 main tank and what is being transported to the  
11 strainer, it's the near field which matters. It's not  
12 the approach velocity normal to that. That's always  
13 puzzled me enormously.

14 CHAIRMAN DENNING: Show us on the figure  
15 where the approach velocity is because I'm not sure  
16 that you answered --

17 DR. BANERJEE: He hasn't answered.

18 CHAIRMAN DENNING: -- correctly on --

19 MR. BETTI: I haven't answered his  
20 question yet, no, but --

21 DR. BANERJEE: He understands it, though.

22 MR. BETTI: I understand his question.

23 CHAIRMAN DENNING: Okay. Now, where is  
24 the approach? I thought you did a circumscribed area.

25 MR. BETTI: Yes. The approach velocity

1 based on the perforated plate area would just be the  
2 strainer flow divided by the areas described right  
3 there. That's the approach --

4 DR. BANERJEE: Which is what you have  
5 shown there.

6 MR. BETTI: That's right. And then if we  
7 calculated the approach velocity based on a cylinder  
8 that matched that plate location there, that's what we  
9 call the approach velocity based on the circumscribed  
10 area.

11 CHAIRMAN DENNING: Right, and which is  
12 this velocity.

13 MR. BETTI: We just calculated both of  
14 them here.

15 CHAIRMAN DENNING: Right. Oh, I'm sorry.  
16 There's the -

17 DR. BANERJEE: Yes. I was just saying  
18 that for --

19 MR. BETTI: His question is an interesting  
20 question. It's one that we wrestle with. You know,  
21 in a turbulent torus, is it more important that we  
22 consider this or is this more important in attracting  
23 specifically a paint particle to the strainer?

24 DR. BANERJEE: I would maintain --

25 MR. BETTI: And so the way that we did it

1 in the report that we had docketed on this, we  
2 actually did that by close observation of the testing.

3 DR. BANERJEE: Well, the testing was with  
4 a single strainer, right?

5 MR. BETTI: It was with a single strainer.

6 DR. BANERJEE: So you got the obvious  
7 answer, which is completely wrong.

8 MR. BETTI: Well, I don't think so because  
9 the testing showed that the particles had to come  
10 right up onto the plate that we tested to stick to the  
11 plate.

12 DR. BANERJEE: Yes, but, I mean, I don't  
13 want to argue. I think it's fairly obvious that if  
14 you have a single strainer, you never have a  
15 circumscribed situation. And the approach velocity is  
16 never into the gaps. You basically made a problem  
17 which has an approach velocity of 0.02 or 0.039.

18 By definition, if you make a stack, that's  
19 a different matter. In your paint chips, you never  
20 made a stack. You just had a single strainer that you  
21 looked at.

22 MR. BETTI: Yes. We can talk a little  
23 about that testing later.

24 DR. BANERJEE: Yes. So I think --

25 MR. BETTI: I understand your point. I

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1 just think that we spent a lot of time studying the  
2 films from that paint testing to make observations to  
3 see were there paint chips being drawn in through the  
4 circumscribed flow or were they being drawn in simply  
5 because we put such a high concentration of paint.

6 We'll talk about that. We found it more  
7 to be as a, you know, you need a lot of turbulence to  
8 keep the paint afloat. And then you need to get that  
9 paint chip close to the strainer so it gets drawn in.

10 So it is more of a macro look at it. We  
11 could have addressed it, you know, in a couple of  
12 different ways. Certainly the answer would have been  
13 cleaner. We wouldn't have had to match the films if  
14 the answer was paint doesn't go to the strainers at  
15 either approach velocity.

16 That would have been a nice answer  
17 engineering-wise, but we had to do more work to  
18 establish that that wasn't the case that we could use  
19 that cylindrical test information to come to --

20 DR. BANERJEE: I think the concern is that  
21 all your work, experimental work, that I have seen --  
22 there may be others -- in the reports are all with  
23 single discs so that when you stack the discs and you  
24 start to have flow into a stacked disc, it is the  
25 approach velocity of the circumference which matters.

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1 MR. BETTI: Yes, not a new question. So  
2 I understand.

3 DR. BANERJEE: And when you have a single  
4 disc, it's a completely different approach velocity.  
5 So I don't see the applicability of any of your  
6 experiments to the case at hand.

7 In fact, the pressure dropped, the  
8 entrainment, none of which is applicable to a stack of  
9 strainers. You're talking about a single strainer  
10 which is completely exposed.

11 MR. BETTI: EPRI did testing on stacked  
12 disc strainers. And they did testing on the NUREG  
13 correlations for stacked disc strainers to assure that  
14 the NUREG correlation that we used for this  
15 circumscribed and then perforated plate area  
16 arrangement was valid. Okay?

17 So the stacked disc was tested at EPRI.  
18 On the previous slide, that was the standard stacked  
19 disc. What I was trying to depict is that our stacked  
20 disc and the standard stacked disc arrangement has  
21 been tested.

22 The reason that we set out to do some more  
23 testing, some specific debris head loss testing, was  
24 more of the issue of we're designing bigger strainers  
25 but lower approach velocities. And even though the

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1 materials had been tested, we wanted to make sure. We  
2 wanted to find out what nuances were involved with  
3 lower approach velocities and a large amount of paint  
4 chips. Those were the key.

5 So we had additional testing done on the  
6 head loss correlations, but you're correct in saying  
7 that that head loss correlation, we were concentrating  
8 on the correlations themselves because so much testing  
9 had already been done with the stacked disc  
10 arrangement at EPRI.

11 DR. BANERJEE: Well, first of all, the  
12 EPRI -- we haven't seen the EPRI test. That would be  
13 a valuable thing to take a look at.

14 MR. BETTI: Okay.

15 DR. BANERJEE: Like all these tests, when  
16 we have looked at them in more detail, almost  
17 everything we have seen in the past is, let's say,  
18 highly disputable. And I've found it very difficult  
19 to understand any of the tests which have been done,  
20 including the ones which were done at Los Alamos.

21 The second aspect is that the correlation,  
22 which I think you also refer to as semi-theoretical,  
23 is, in fact, neither theoretical nor semi in any way.  
24 To call it theoretical is just incorrect. There's no  
25 basis in theory for that correlation, which there have

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1 been notes written on as well.

2 That correlation is also suspect. So it  
3 would be very interesting to see what evidence EPRI  
4 has gathered to support that correlation.

5 MR. BETTI: You're calling into doubt the  
6 NUREG correlation that was accepted by the NRC.

7 DR. BANERJEE: It may or may not be  
8 accepted. The fact remains that when we have  
9 reexamined this correlation, it has had severe  
10 problems interpreting some of the very recent data  
11 that has been taken.

12 MR. BETTI: I just don't --

13 DR. BANERJEE: Have you seen the most  
14 recent data?

15 CHAIRMAN DENNING: Now, which data are you  
16 referring to, Sanjoy, Los Alamos?

17 DR. BANERJEE: Los Alamos data. So we  
18 would like to see the EPRI results, look at it, and  
19 see how well this correlation bounds it. If it's in  
20 a stacked disc as well, is the data taken in a  
21 situation where the gaps have filled up? And so it's  
22 completely circumscribed.

23 MR. BETTI: Well, they did it both ways.  
24 They did the relationship between unfilled and filled.  
25 They made sure their correlation worked through that

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1 --

2 MEMBER WALLIS: Once the gaps fill up, the  
3 strainer really stops functioning as a very good  
4 strainer. And it's filled. And that's it. And  
5 anything else has to go on the outside.

6 MR. BETTI: It still functions as a  
7 strainer.

8 MEMBER WALLIS: But it doesn't function  
9 very well because it's lost all its area. It's lost  
10 most of its area.

11 DR. BANERJEE: And the approach velocity  
12 is --

13 MEMBER WALLIS: Anyway, you're going to go  
14 on.

15 MR. BETTI: Yes. All right. So at  
16 Vermont Yankee, we designed our strainers for our  
17 conservative suppression pool debris loads. We were  
18 using the NUREG correlations that were validated  
19 through testing.

20 We did some minor modifications of that  
21 testing based on the LNC chuck testing that we did in  
22 this test facility to account for VY's debris  
23 combinations and approach velocities.

24 And then when we get this test data, then  
25 that information is correlated to head loss in our

1 suppression pool by just adjustments in viscosity and  
2 the --

3 MEMBER WALLIS: You had 50 percent of the  
4 finds are retained or something like that?

5 MR. BETTI: Right. Take the --

6 MEMBER WALLIS: The other ones go right  
7 through?

8 MR. BETTI: Right.

9 MEMBER WALLIS: They normally go through  
10 the reactor and come back again?

11 MR. BETTI: Yes.

12 MEMBER WALLIS: And they get called the  
13 second time around?

14 MR. BETTI: Right. That's based on  
15 testing, too.

16 MEMBER WALLIS: Do you only assume 50  
17 percent of them in your --

18 MR. BETTI: They do. And in a minute,  
19 we'll talk to that number, Graham. And I think you  
20 will feel a little differently when you see how much  
21 of those finds we use in our test and how much of the  
22 finds that we have in our --

23 MEMBER WALLIS: The other thing I didn't  
24 see was -- well, there's a time effect. In all of  
25 this Los Alamos test, there's a mysterious time

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1 effect.

2 And then there was also this thin bed  
3 effect, which can form anywhere. You can get a matrix  
4 and then some time later you get a thin bed on top of  
5 it or something. And there were all kinds of warnings  
6 about you have to be able to calculate it. I didn't  
7 see anything about a thin bed effect in your analysis.

8 Is that because you couldn't figure out  
9 how to do it or just assumed it's homogeneous and --

10 MR. BETTI: You might have to -- I don't  
11 know what you mean by a "thin bed."

12 MEMBER WALLIS: Well, I'm not going to say  
13 what I mean, but Los Alamos says there's a thin bed  
14 effect, which was actually found in BWRs a long time  
15 ago.

16 MR. NICHOLS: To be clear here, you're  
17 referring to the recent testing done as part of the --

18 MEMBER WALLIS: They came here and talked  
19 to us. And they said at any place in this bed, you  
20 know, you've got a mixture of fiber and fines. So you  
21 could get a thin layer of fine material, which has a  
22 much higher pressure drop than it would have, which  
23 was dispersed in everything else.

24 MR. BETTI: Okay. Now I understand.

25 MEMBER WALLIS: It's like the mud that the

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1 beaver puts on the dam that seals it up.

2 MR. BETTI: That's right.

3 MEMBER WALLIS: That's what they were  
4 concerned about.

5 MR. BETTI: And when we did our head loss  
6 testing, there were those effects. And that fact is  
7 into the calculated head loss as recorded. In other  
8 words, if you take a stack of debris and you try to  
9 correlate it real well and drop it real fine into a  
10 pipe, it doesn't disperse homogeneously. And the  
11 strain of loss is really a function about how all that  
12 debris stacks up.

13 MEMBER WALLIS: That's right.

14 MR. BETTI: And there's a lot of  
15 randomness in those. So if you take an ideal  
16 correlation for debris head loss and assume that  
17 everything stacks up randomly and you get this really  
18 fine correlation through that method and then you say,  
19 "Well, gee, now I'm going to change my slides by four  
20 percent. So, therefore, my head loss is going to  
21 change by .07 percent," I say hogwash. And I've  
22 always said hogwash because we ran a series of tests.

23 And when you look at one of these  
24 strainers, when they have debris on them, they're  
25 anything but homogeneous. And then you take a

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1 cylinder and you put it in a pool and you take these  
2 kinds of low approach velocities when the paint chip  
3 and other component settling velocities can be as high  
4 as .2 feet per second. You end up with most of your  
5 debris at the top of the strainer or areas away from  
6 the flow. All right?

7 So what our approach was -- and this is  
8 something that I have just bounced up and down on when  
9 anybody says, "We're going to start employing one of  
10 these correlations to change our head losses" -- to  
11 put the debris in the most conservative combinations  
12 that we think you can get on any of these strainers.

13 MEMBER WALLIS: Most conservative is  
14 usually to put all of the fiberglass on first and put  
15 all of the sludge on top.

16 DR. BANERJEE: I also noticed that you ran  
17 a --

18 MR. BETTI: But what I was getting at is  
19 that when we ran these tests with these size  
20 strainers, that you would end up with not a full  
21 debris bed but patches of debris and patches of opens.  
22 Okay?

23 So your head loss is more a correlation  
24 about how many open areas you have versus what your  
25 debris loss is through your correlation. So when we

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1 are said and done with these correlations, what we  
2 maintain is we establish from this test with a  
3 conservative concentration of debris, we establish the  
4 head loss for the VY strainers. And that's the head  
5 loss we maintain.

6 We don't go back and say, "Okay. We only  
7 got 75 pounds of sludge, not 700 pounds of sludge,  
8 like we assume here."

9 And so they say, "Well, gee, that's great.  
10 Sludge causes most of our head loss." Therefore,  
11 instead of, you know, one foot, now we have .2 feet.

12 We say, "No." A head loss is what we  
13 establish during those tests. And we keep those head  
14 losses in our MPSH calculation.

15 DR. BANERJEE: Let me go back. If I  
16 understand how you did these calculations, you used a  
17 computer program called H-loss, right?

18 MR. BETTI: Yes.

19 DR. BANERJEE: And this was run for you by  
20 a corporation called ITS?

21 MR. BETTI: Yes.

22 DR. BANERJEE: What you did, if I  
23 understand it, is that you zoomed because you had to  
24 zoom ascertain porosity or a solid density. It was .2  
25 if I look at the results. Those were based, if I

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1 understand it correctly, on some experiments we have  
2 done with single strainers.

3 The situation that you have there is very  
4 different because what you've got is a stacked set of  
5 strainers into which the material is accumulating.  
6 And when it eventually builds up to the edges there,  
7 then this amount of debris which is stopped between  
8 those plates acts as a filter. No test that I saw  
9 looked at any situation like this to know what the  
10 true density might be.

11 As the fine particles go through this  
12 fiber bed, which is stuck on these strainers, the  
13 density could well be higher or lower. I have no  
14 idea.

15 MR. BETTI: That's right.

16 DR. BANERJEE: I'm simply saying I just  
17 don't know.

18 MR. BETTI: Right.

19 DR. BANERJEE: Secondly, in the head loss  
20 correlation, which is the NUREG 6224, the tuning  
21 parameter is SV, the surface area per unit volume,  
22 which is what they tune to fit experiments basically.  
23 And by tuning it sufficiently, you can fit any  
24 experiment.

25 But the problem that arises is that

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1 between experiments, you get very different SVs to fit  
2 the data. So almost every experiment has a different  
3 SV. Okay?

4 Now, I actually looked for your value of  
5 SV, which was used. And I couldn't find it. I went  
6 over your reports with a fine-toothed comb. So that  
7 must have been an input parameter to tune against the  
8 experiments, which may have been done by ITS. It  
9 would be very interesting to know what SV they used  
10 because there is data now on typical SVs for fiber and  
11 particle mixed beds, which compact more and more as  
12 you go.

13 And those are pretty thick beds now you're  
14 talking about, thick because they're about an inch,  
15 like this. They're deep. I don't know how deep they  
16 are. But you could well have very different densities  
17 through that bed --

18 MR. BETTI: Yes, but that's --

19 DR. BANERJEE: -- from the ones that  
20 zoomed to the calculation.

21 MR. BETTI: The densities used in our  
22 calculations --

23 DR. BANERJEE: .2.

24 MR. BETTI: Yes, but that was based on the  
25 measured density from the --

1 DR. BANERJEE: Was measured on a single  
2 strainer.

3 MR. BETTI: Single strainer, exactly.

4 DR. BANERJEE: It was very different from  
5 that situation.

6 MEMBER WALLIS: As long as presumably the  
7 gap doesn't fill up very much, they may be okay.

8 MR. BETTI: That's right.

9 MEMBER WALLIS: As long as the pressure --

10 DR. BANERJEE: The gaps are only one-inch.

11 MEMBER WALLIS: No. As long as the  
12 pressure drop is very low, it doesn't compress the  
13 bed. And lots of the effects that we worry about  
14 don't occur.

15 MR. BETTI: Yes. I think it says it in  
16 the report that we docketed when we originally  
17 designed these strainers, we designed them not to fill  
18 up, but --

19 MEMBER WALLIS: They get pretty close at  
20 the limit.

21 MR. BETTI: Yes. And because of the  
22 approach velocities for lower, the density ended up  
23 being lower. So, therefore, we did get a little bit  
24 of external buildup of the debris.

25 DR. BANERJEE: Well, but even if you do

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1 get half an inch buildup on each side, you're still  
2 going to close that gap.

3 MEMBER WALLIS: Right.

4 MR. BETTI: But, in reality, you put one  
5 of these strainers in a pool with this kind of  
6 strainer drop and you take this discussion and you  
7 look at the bottom of these strainers, you're going to  
8 find that the bottom of the strainer has got holes all  
9 over it.

10 In reality, the pressure drop is just  
11 going to be a function of the amount of open area in  
12 the bottom of the strainer. So it's not as  
13 theoretical as you think. And I think that we have a  
14 conservative design that's going to give us a very,  
15 very low pressure drop. And that's --

16 DR. BANERJEE: You're saying the stuff  
17 falls down from the bottom?

18 MR. BETTI: Yes. It falls down from the  
19 bottom.

20 DR. BANERJEE: The bottom of the pool?

21 MR. BETTI: Yes. It only collects on the  
22 sides. And there's a lot of open areas on the bottom  
23 of these strainers.

24 DR. BANERJEE: This isn't up against the  
25 wall somehow? I thought you showed us --

1 MR. BETTI: Can we go back to the slide?

2 DR. BANERJEE: It was resting on a wall or  
3 something.

4 MR. BETTI: No. We'll look at that, at  
5 the section.

6 MEMBER WALLIS: It actually falls off the  
7 strainer as it builds up?

8 MR. BETTI: Yes. I mean, it would build  
9 up in this quiet area over here, but there would be  
10 very little debris in the areas over here.

11 MEMBER WALLIS: It's a self-cleaning  
12 strainer?

13 MR. BETTI: No. I think it's just the  
14 fact that when there's any turbulence or any moisture  
15 in the water in the front end, debris kind of collect  
16 in the quiet areas in the back end. So it's going to  
17 concentrate the debris collection on one side.

18 So if we say size the strainers, which we  
19 did, to take all the nukon without going into the gaps  
20 and we assume it all builds up evenly; in fact, it  
21 does build up evenly, gravity in dead areas,  
22 concentrate some of the material so there's a lot less  
23 for the other areas.

24 It's not like the strainer is designed and  
25 there's an infinite amount of -- I mean, some of these

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1 plants designed for feet of nukon material. And we  
2 design basically to have a thin coat of material for  
3 all our strainers.

4 DR. BANERJEE: The issue I suppose would  
5 be that as the top got full of debris, which I agree  
6 would happen, then the flow would drop through it.  
7 And you'd start to get much higher flow through the  
8 bottom, --

9 MR. BETTI: Right.

10 DR. BANERJEE: -- which would ultimately  
11 clog up again.

12 MEMBER SIEBER: It's the approach velocity  
13 that controls how much adheres.

14 DR. BANERJEE: You going to get a lot  
15 higher approach velocity at the bottom.

16 MEMBER SIEBER: As time goes on.

17 DR. BANERJEE: As time goes on.

18 MR. BETTI: That's a geometry problem, but  
19 there is a bigger gap in approach velocity because,  
20 like you say, when you fill those gaps, you have quite  
21 a large reduction in area.

22 DR. BANERJEE: Sure.

23 MR. BETTI: But, then again, if you don't  
24 fill the bottom gaps because you dump four inches of  
25 strainer in the quiet areas at the top area, you still

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1 end up with a larger effect of working area of your  
2 strainer.

3 DR. BANERJEE: Well, I think the first  
4 thing that we should do is take a look at these EPRI  
5 experiments because we didn't have access to those at  
6 the moment and see what strainer behavior was, what  
7 mix they used, and what sort of -- did they use  
8 fibrous material as well as particle?

9 MR. BETTI: Yes. Fibrous and sludge, yes.

10 DR. BANERJEE: And sludge. So that would  
11 be a good point to start.

12 MR. BETTI: The only thing new here is the  
13 high paint chip quantities. We're going to talk to  
14 that because the basis for high paint chips was  
15 something we're going to get into in a little bit.

16 CHAIRMAN DENNING: Would you go ahead and  
17 proceed, then?

18 MR. BETTI: Thank you.

19 CHAIRMAN DENNING: And let's move more  
20 quickly now through.

21 MR. BETTI: All right. We included a  
22 slide that was design debris low quantities for the  
23 torus in here. You'll see line 1, we have nukon  
24 insulation. That was the URG allowed you to do  
25 basically the zone of influence.

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1 We took the approach where we took on one  
2 whole research system. We took the lazy approach,  
3 where we just used the whole research system and get  
4 to use half our nukon and assume that that was blown  
5 off in a jet.

6 We had when we did this testing a lot of  
7 TempMat that was on our temporary mat insulation. A  
8 lot of that since has been removed, but we don't take  
9 that out of our correlation. That's been replaced  
10 with RMI insulation.

11 We still have some RF flex insulation in  
12 our drywell. You'll note that we assumed in this that  
13 we had -- in addition to some of the URG-recommended  
14 values, that we included 622 pounds of sludge from our  
15 torus. And what --

16 DR. BANERJEE: That's not in your source  
17 term here. It says much lower than that. I have this  
18 report, which is your source term here.

19 MR. BETTI: Yes.

20 DR. BANERJEE: And it seems that what you  
21 did was 159 plus 50 plus 27 and you took 150 from the  
22 drywell. So I don't see how you got that 772 number.  
23 This was not consistent with your report, which I have  
24 in front of me, which is on VY. It's called "Debris  
25 Source Terms for Sizing of Replacement Residual Heat

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1 Removal and Core Spray Strainer, VY C1677."

2 MR. BETTI: One, six, seven, seven?

3 DR. BANERJEE: Yes. The numbers are 159  
4 plus 50 plus 27 plus 150. And the 150 came from the  
5 drywell.

6 MR. BETTI: That's true. Let me explain  
7 it a little bit. I don't know what before you were  
8 talking about. I'll clarify that a little bit.

9 When we set up the design test cases in  
10 the debris loading for the design of the strainers,  
11 these are the numbers on the board that we used.  
12 Okay?

13 Six seventy-seven was then -- after that,  
14 that calc was written. And those numbers were put in  
15 there that reflect more realistic sludge factors.

16 But the debris head loss correlations that  
17 we maintain in our MPSH calculations are those that  
18 are developed in VY C1924. Our 808 calc uses the  
19 debris head loss calculations in 1924. Those head  
20 loss calculations in 1924, the basis of those, is the  
21 debris quantities that we put in the design spec and  
22 that we tested it at Alden.

23 So there's a 1677 calc that tries to put  
24 together what a realistic head loss would be and  
25 sludge loading for our plants, but, as I started to

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1 say in this conversation, we maintain the values from  
2 1924. And these are the values that went into the  
3 1924 calculation.

4 DR. BANERJEE: Do we have 1924?

5 MR. BETTI: I think you got that one, yes.

6 DR. BANERJEE: Here the basis is very  
7 clear. You say you have an 18-month fuel cycle. And  
8 based on the debris, the sludge that has been removed,  
9 on the second, you give 159 pounds of dry sludge.

10 MR. BETTI: Right, right.

11 DR. BANERJEE: And, as a conservative  
12 measure, you add 50 pounds of sludge to that.

13 MR. BETTI: Right.

14 DR. BANERJEE: And 27 pounds are added  
15 after that to provide some operational flexibility,  
16 which gives you 6 months additional time between torus  
17 cleaning.

18 MR. BETTI: That's right. And then --

19 DR. BANERJEE: So I can follow this logic  
20 very clearly, what you said.

21 MR. BETTI: That's right. Right.

22 DR. BANERJEE: But it's not incredibly  
23 conservative or anything. You just are doing  
24 something which is roughly right.

25 MR. BETTI: Roughly right, yes.

1 DR. BANERJEE: There's not a huge --

2 MR. BETTI: And that was based on, like  
3 you say, a sludge quantity of around 50-59 pounds per  
4 --

5 DR. BANERJEE: One fifty-nine pounds  
6 because you don't clean every refueling cycle, seen  
7 every second.

8 MR. BETTI: Yes, but it was 50 some odd --

9 MEMBER WALLIS: Fifty-three pounds a year  
10 it says here.

11 MR. BETTI: Fifty-three pounds a year,  
12 right, and --

13 DR. BANERJEE: So the refueling being  
14 every 18 months, and you say every second refueling  
15 cycle you're cleaning.

16 MR. BETTI: Right. So that was based on  
17 the first time we did this cleaning and the guys  
18 started canting, somewhat decantoring the debris in  
19 the bottom of the torus.

20 We hadn't painted our torus at that point.  
21 We had old paint, a little bit of rust, et cetera.  
22 And that was the quantities we came up with.

23 So what we did for the strainer design  
24 specification that determined the quantities for  
25 testing was increased those values so that we were

1 testing a conservative potential sludge load. Okay?

2 In 1924, we -- in the spec, VY S049,  
3 you'll see a bunch of debris load cases that are based  
4 on these sludge quantities based on the split  
5 fractions of each of the pumps.

6 Then at Alden, they ran the test on those  
7 equivalent debris quantities. Then the VYS --

8 DR. BANERJEE: I guess we have this in the  
9 report that I need to look at, look at the basis of  
10 how you did it. It's 1924? I've got it. We'll look  
11 at it.

12 MR. BETTI: So what I'm saying is that --

13 DR. BANERJEE: I'll check.

14 MR. BETTI: -- 1924 we use as the basis,  
15 then. Those head losses are then what is used in our  
16 808 calculation. All right?

17 DR. BANERJEE: Now, the report, the head  
18 loss calculations, is it documented in that one that  
19 used H-loss, then?

20 MR. BETTI: Yes.

21 DR. BANERJEE: That was the ITS study?

22 MR. BETTI: Right. It's I think the 1924  
23 calculation. Bruce should have a copy of it with --

24 DR. BANERJEE: Yes. Nineteen twenty-four,  
25 we have that.

1 MR. BETTI: That was actually --

2 DR. BANERJEE: Do we have that?

3 MR. BETTI: It was --

4 DR. BANERJEE: Well, I'll check it out.

5 MEMBER WALLIS: Make sure it's on that  
6 internet thing we have access to.

7 DR. BANERJEE: Yes. Nineteen twenty-four  
8 is there.

9 MEMBER WALLIS: It is there? Okay.

10 CHAIRMAN DENNING: Let's move forward,  
11 then, please.

12 MR. BETTI: Thanks, Bruce.

13 All right. Now, the thing that kind of  
14 made our plant unique in this regard at the time was  
15 a high quantity of paint assumed to end up in our  
16 torus.

17 We had contracted with CDI and GE to kind  
18 of look at our paint and determine what was qualified,  
19 what was unqualified. What they basically said was,  
20 "Gee, we have to get in there. And we have to do --  
21 you would have to do some testing, look at this paint,  
22 make sure if it's qualified or unqualified."

23 Because we had a deadline for compliance  
24 with 9603, the decision was made to treat all top coat  
25 painting in our drywell and torus as unqualified until

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1 we proved it to be qualified.

2 That ended up with basically about 75,000  
3 square foot paint that ended up in our torus. And  
4 that was the assumption that was used to develop the  
5 paint loadings that we used in our paint debris  
6 testing at all.

7 Then what we did is because we knew we  
8 were doing settlement tests, we tried to get a very  
9 light paint. We tried to get a paint that was  
10 representative of our paint, thin, in a size that  
11 would have the least tendency to sink.

12 So those were the characteristics that we  
13 picked for the paint. We had a bounding amount of  
14 paint. We picked the paint that was the same long  
15 variety that we used until we tried to pick  
16 thicknesses, dimensions, et cetera, densities that  
17 would give us the most buoyant effect to the paint so  
18 that it had the most likelihood of being dried. All  
19 right.

20 DR. BANERJEE: I have here the sludge, but  
21 it doesn't seem to be that much, the number. Is there  
22 something weird in how I should interpret these?

23 MR. BETTI: Yes, because each of those --

24 DR. BANERJEE: It says "Sludge 91.5  
25 pounds." Is this for per strainer or something?

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1 MR. BETTI: Yes. It's per strainer based  
2 on split fractions and flow and conditions for each of  
3 the strainers. So depending upon the condition you're  
4 talking about, if you say you dump a total of 700  
5 pounds of sludge to your torus and you have three  
6 pumps, one core spray, two HR pumps running, there  
7 will be a distribution of that debris to the  
8 strainers. And then we have a short-term strainer  
9 loading and then a long-term strainer loading. In  
10 certain periods, they often turn on pumps.

11 DR. BANERJEE: I guess we need to go  
12 through this in detail.

13 MR. BETTI: We can do that.

14 CHAIRMAN DENNING: Continue.

15 MR. BETTI: All right. To give you an  
16 example on the sludge, in 2004, we did another sludge  
17 removal. That was 75 pounds after 6 years. And,  
18 again, we're assuming 772 pounds in our test data. So  
19 I'm just trying to emphasize here that our testing is  
20 done at very conservative values and our head losses  
21 were done with very conservative values.

22 Next slide, please. That concludes the  
23 discussion on the debris. And we have Bruce Slifer  
24 we're going to turn it over to for a little discussion  
25 on the issue of submergence and air ingestion.

1 MR. SLIFER: My name is Bruce Slifer. I'm  
2 with Vermont Yankee.

3 We'll talk about some of the testing that  
4 has been done to determine if there's any potential  
5 for formation of an air core vortex in air ingestion  
6 through these strainers.

7 There are a couple of tests that were  
8 conducted which give some indications of the  
9 conditions under which this type of phenomena might  
10 occur. The first series of tests that I want to  
11 discuss are the Alden Research Lab tests that were  
12 documented in NUREG CR-2772.

13 Those tests were done with a strainer,  
14 which is basically a strainer that was typical of the  
15 strainer designs in place at the time. These tests  
16 were done in 1982. And this strainer configuration  
17 was a codicle strainer, much shorter in length than  
18 the kinds of strainers we're talking about that are  
19 installed at Vermont Yankee today. But they still do  
20 give some kind of indications of the potential for  
21 vortex formation.

22 The diameter pipe was two feet, which is  
23 in --

24 MEMBER WALLIS: Horizontal pipe?  
25 Horizontal?

1 MR. SLIFER: Yes, it was horizontal. The  
2 orientation was --

3 MEMBER WALLIS: So as is the distance of  
4 both the top of the pipe. Is that what it is?

5 MR. SLIFER: I'm sorry? I didn't --

6 MEMBER RANSOM: The submergence? Is that  
7 the --

8 MEMBER WALLIS: It's from the top of the  
9 --

10 MR. SLIFER: Submergence is from the  
11 center line of the pipe to the top of the pool. The  
12 flow rate was 12,000 gpm maximum, which is much higher  
13 than the flow rates we see in our strainers. The  
14 calculated Froude number was .8. And under those  
15 conditions, they concluded that there was no air core  
16 vortexing; therefore, no air ingestion.

17 Next slide, please. Much more typical or,  
18 I should say, applicable to Vermont Yankee's situation  
19 today was EPRI testing of the PCI stacked disc  
20 prototypes. Again, the diameter of the core tube is  
21 two feet.

22 They did a test where the submergence was  
23 one and a half feet, which left the top portions of  
24 the disc exposed and at a flow rate of 10,000 gpm,  
25 again with a flow rate much higher than we see typical

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1 of our strainers, calculated Froude number 1.11.  
2 There was no vortex observed. In the next slide,  
3 we'll show you a picture of that.

4 So this is the picture of that particular  
5 test with a ran between 5,000 and 10,000 gpm, with the  
6 upper portion of the disc exposed. It's a bubble  
7 formation in the pool, but there was no vortex  
8 indicated and no air ingestion in this test.

9 Next slide, please. Now, specifically for  
10 Vermont Yankee, we have, of course, two different  
11 types of strainers. There's a core spray strainer.  
12 We had a maximum flow rate of 4,600 gpm, submergence  
13 of 4 feet, which is the basis that we use in our  
14 calculation of available MPSH based on the suppression  
15 pool levels after a LOCA.

16 Our calculated Froude number based on the  
17 core tube by an order of two feet is --

18 MEMBER WALLIS: Is this a different Froude  
19 number than you had in the previous slides were based  
20 on this?

21 MR. SLIFER: That was based on two feet.

22 MEMBER WALLIS: I had a lot of trouble  
23 with these different Froude numbers. The Froude  
24 number in the EPRI report is based on the submergence,  
25 and yours here is based on the tube diameter.

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1 MR. SLIFER: Well, it's based on diameter  
2 and its submergence. Both the diameter is important  
3 for the extermination of the flow velocity.

4 MEMBER WALLIS: The velocity. Well, you  
5 take velocity over the square foot of GD or you take  
6 velocity over square root of GS.

7 MR. SLIFER: GS.

8 MEMBER WALLIS: That's this definition  
9 here?

10 MR. SLIFER: Yes.

11 MEMBER WALLIS: What does it say based on  
12 a few cord, then?

13 MR. SLIFER: Well, because the second part  
14 is the lot based because of --

15 MEMBER WALLIS: The loss is based on the  
16 gauge, but the Froude number is based on S.

17 MR. SLIFER: It's based on S and D.

18 MEMBER WALLIS: Yes. But based on  
19 velocity, it's V over squared of GS.

20 MR. SLIFER: Correct.

21 MEMBER WALLIS: So it's really what I  
22 would call based on --

23 MR. SLIFER: Well, the reason I did this,  
24 because the second problem that I show here is based  
25 on the circumscribed surface area that we talked about

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1 earlier.

2 MEMBER WALLIS: I see. Okay.

3 MR. SLIFER: So that affects your approach  
4 velocity.

5 MEMBER WALLIS: That's irrelevant. That's  
6 based on the velocity of the surface area.

7 MR. SLIFER: Correct.

8 MEMBER WALLIS: Okay.

9 MR. SLIFER: Again, based on the testing  
10 that was done and those low values for approach  
11 velocity and the low Froude number, in that  
12 submergence, there would be no vortex formation.

13 MEMBER WALLIS: You know, there's a basic  
14 problem here that what happens depends both on the  
15 Froude number and the ratio, S over D, and this other  
16 geometry of the strainer.

17 So just using Froude number alone isn't a  
18 good enough criterion.

19 MR. SLIFER: Both Froude number and  
20 submergence.

21 MEMBER WALLIS: I think you may be okay if  
22 you use both of them here. If you have bigger  
23 submergence and a smaller Froude number, --

24 MR. SLIFER: Correct.

25 MEMBER WALLIS: -- that's okay. If you've

1 just got one of them, it's probably not all right.

2 MR. SLIFER: Well, this is really based on  
3 both. It has the --

4 MEMBER WALLIS: What concerned me was when  
5 you had this fully loaded strainer which was sort of  
6 one inch below the surface in the minimum level.  
7 That's disappeared now, has it?

8 MR. SLIFER: Yes. I'll get to that point.

9 MEMBER WALLIS: So that's old hat? That's  
10 no longer valid?

11 MR. SLIFER: That's true.

12 MEMBER WALLIS: Okay. Because which  
13 report was that? Was that the 1677 or was that more  
14 up to date than that? That was 1920, wasn't it?

15 MR. SLIFER: I believe it was 1920. I  
16 think, as Rico explained --

17 MR. BETTI: Yes. I explained it. I  
18 wanted to make sure that our strainers were designed  
19 with some margin. And the calculation there may have  
20 had some weak spots, but we knew we had significant  
21 margin.

22 And based on EPRI tests, et cetera, these  
23 Froude numbers, we really didn't think we had an air  
24 ingestion --

25 MEMBER WALLIS: That's where I have a

1 little trouble because you said you had this Froude  
2 number based on I think a 5-foot or a 1.5-foot  
3 submergence. And then you applied it to what looked  
4 like a .2 feet submergence.

5 MR. SLIFER: Right.

6 MEMBER WALLIS: It didn't make any sense.

7 MR. BETTI: To clarify, that's not .2 feet  
8 because the strain is 47 inches in diameter plus .19  
9 feet.

10 MEMBER WALLIS: So that's not down to the  
11 axiom?

12 MR. BETTI: It's down to the axiom.

13 MEMBER WALLIS: All right.

14 MR. BETTI: And the velocity of our  
15 strainer is quite a bit lower than the velocity of  
16 that test. So that's the difference.

17 MEMBER WALLIS: I think it's not just the  
18 vortex you're worried about because the floating  
19 debris, the Armaflex floats around and presumably gets  
20 drawn --

21 DR. BANERJEE: It's the Armaflex moving.

22 MEMBER WALLIS: -- to the region of the  
23 strainer, which if you had a drawdown like this, you  
24 would actually draw down the Armaflex into the --

25 MR. SLIFER: I think we've got the next

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1 slide.

2 DR. BANERJEE: Because you argue that the  
3 Armaflex never gets to -- it wouldn't get to the  
4 deeper one, to the CS one.

5 MR. SLIFER: Basically if you used the  
6 minimum values of the suppression pool you would  
7 expect after a LOCA with the debris floating on top of  
8 the surface, the submergence to the top of the debris  
9 bed would be 1.8 feet to 3.3 feet for the strainer.  
10 So the debris would be quite a difference above the  
11 top of the debris bed.

12 MEMBER WALLIS: The top, very top, of the  
13 --

14 MR. SLIFER: Very top of the debris bed.

15 MEMBER WALLIS: Top to the --

16 MR. SLIFER: The top of the debris bed.

17 MR. BETTI: So what we are theorizing here  
18 is that .1 percent velocity, which is going to draw  
19 the foam insulation down to 3.3 feet of water. I'm  
20 not a fluid expert, but I wouldn't think so.

21 DR. BANERJEE: Well, it's more the problem  
22 with the CRS, rather than the RHR. The concern is  
23 because they are closer to the surface.

24 MR. BETTI: The velocity is lower, yes.

25 MR. SLIFER: Again, the Froude number is

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1 --

2 MEMBER WALLIS: Now, what concerns me a  
3 bit here is that we have seen all these reports. And  
4 some of us have read them. I think Sanjoy and I have  
5 read them. And there seems to be a series of them  
6 that develop.

7 Sometimes one is replaced by another. And  
8 what you're telling us today is different from what is  
9 in the report. So all we have is some sort of oral  
10 presentation to go on. We don't have the sort of  
11 final word written down so we can really look at it  
12 and say, "Yes, we believe it."

13 DR. BANERJEE: Yes. The reason is it's  
14 something maybe that is very explainable, but, for  
15 example, your case 2B is the worst case for your RHR.  
16 There your slide number is 490-something. And here  
17 you're putting 722. Which is right? We don't know.

18 MR. SLIFER: I guess all I can explain to  
19 you is it's based on specific part flow. So this is  
20 a fraction evaluation that needs to go into the  
21 strainer loading.

22 If we had X quantity of debris in the  
23 strainer, it's only a portion of that that would get  
24 to the debris --

25 DR. BANERJEE: This is the total.

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1 MR. SLIFER: For one strainer.

2 MR. BETTI: For one strainer.

3 MR. SLIFER: There are scenarios working  
4 in conjunction with that debris loading.

5 DR. BANERJEE: But, anyway, it's  
6 confusing. If after reading this report, I don't  
7 understand what you have done, then other people would  
8 also be confused.

9 MR. SLIFER: Nobody would be confused who  
10 was involved with the 9603 process for a number of  
11 years and went through these large design changes and  
12 the acceptance of that methodology. None of us would  
13 be confused.

14 DR. BANERJEE: But there was to be a final  
15 document, right?

16 MEMBER WALLIS: You have to convince  
17 somebody else. That's the problem. You may be sure,  
18 but you have to have some sort of argument which  
19 somebody else can follow.

20 It seems to me that probably you've got a  
21 good story here. I think probably, probably you have  
22 a good story, but it isn't really --

23 DR. BANERJEE: I'm not convinced about the  
24 paint chip business, frankly, because that's a matter  
25 of timing. If you look at the story in your reports,

1 the argument, really, is that early in your LOCA, the  
2 level of turbulence is very high. But paint chips are  
3 all entrained and everything, whatever.

4 But then your approach velocity is, look,  
5 because these things haven't clogged. Okay? So it's  
6 only late in your LOCA that --

7 MR. SLIFER: Yes.

8 DR. BANERJEE: But your core doesn't  
9 calculate buildup, you see?

10 MR. SLIFER: Right, but we could.

11 DR. BANERJEE: You could.

12 MR. SLIFER: I mean, we could bound your  
13 assumption and say that for the minute and 66 seconds  
14 that the high turbulence phase happens, how much paint  
15 could get -- you know, bound your paint. How much  
16 would get there? What would your head loss be for  
17 that event?

18 DR. BANERJEE: Well, yes. The first thing  
19 is the assumption that high turbulence only lasts for  
20 60 seconds. When you have a LOCA coming into this  
21 drywell and turning this thing off, I mean, any  
22 turbulence calculation you are likely to do is not  
23 going to last for the 60 seconds. Even the decay of  
24 turbulence would take much longer.

25 But, leaving that aside, the worst case

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1 here turns out to be the IB, where you've got the LOCA  
2 going on and on for a long period of time and keeping  
3 on stirring it up from the viewpoint of the paint  
4 chips.

5 That's also documented because you sort of  
6 say that your level of turbulence is high for -- I  
7 don't know -- many hundreds of seconds, see? So that  
8 begins to look like the limiting case.

9 I'll give you the references. It's your  
10 own report.

11 MR. SLIFER: What I have here is our  
12 submittal, which was from one of our reports, which  
13 was the one we gave the most scrutiny --

14 DR. BANERJEE: Right.

15 MR. SLIFER: -- to make sure that it was  
16 written right. And this is page 16 of 32. And this  
17 is our December 29, 1999 submittal for what we did for  
18 the testing. This is BBY 99-164. What it says, the  
19 section strain, it says, "At a medium pool turbulence  
20 level, like for an IBA, most of the paint debris  
21 settled to the floor and little remains suspended  
22 where it could be ultimately deposited on the  
23 strainers.

24 It was only at high debris turbulence.  
25 And then when you shut off the pumps and you had the

1 high approach velocity using the circumscribed area  
2 that you could get debris to come to the strainers.  
3 If you had the high turbulence, neither nukon nor the  
4 paint could stick to the strainers because the  
5 turbulence velocities were much higher than the  
6 approach velocities.

7 DR. BANERJEE: Yes. I understand the  
8 argument.

9 MR. SLIFER: In the intermediate, we could  
10 not keep the paint suspended. So I don't --

11 DR. BANERJEE: Yes. But the turbulence  
12 level is arbitrarily set as high, medium, low. What  
13 does that mean to begin with? But, leaving that  
14 aside, your approach velocity always for these  
15 strainers is based on your circumscribed case because,  
16 really, what is bringing the paint to the outside of  
17 this is the flow into those gaps. You know, as soon  
18 as you come near to that, that's what the velocity is.

19 MEMBER WALLIS: It's unlikely to go out  
20 again once it gets in.

21 DR. BANERJEE: Yes. What does it do?

22 CHAIRMAN DENNING: We're going to have to  
23 bring this discussion to a close pretty quickly. So  
24 why don't you take your last couple of slides?

25 MR. SLIFER: This is my last slide, I

1 believe. There was a question raised at some point  
2 about the potential for not keeping the suction lines  
3 full. I think that may have been oriented on an  
4 assumption perhaps if you --

5 MEMBER WALLIS: Only if you have a very  
6 low level.

7 MR. SLIFER: Yes, very low level and a  
8 horizontal run. But, of course, there is a vertical  
9 drop from our strainer down to the pumps, which are  
10 located on another floor. So those are seven feet and  
11 eight and a half feet.

12 And, again, since there's no air vortices,  
13 the suction lines are kept full. And the static head  
14 is not degraded.

15 CHAIRMAN DENNING: Talk to us, then, about  
16 if you know the numbers, the head losses you're  
17 predicting through the debris in comparison with the  
18 six psi that is associated with the overpressure  
19 credit.

20 MR. SLIFER: Our debris head loss is on  
21 the order of half a foot. So we're talking less than  
22 a couple of tenths of a psi.

23 DR. BANERJEE: But, of course, if they get  
24 plugged up, it can be very high.

25 MR. BETTI: That is based on the strainer

1 design head losses, not based on calculated debris  
2 loss.

3 MR. SLIFER: I guess we have to --

4 CHAIRMAN DENNING: What was that again?  
5 Say that again.

6 MR. BETTI: It's based on the bounding  
7 debris quantities used in the strainer specifications  
8 that we put here, like we don't take credit for sludge  
9 reductions, new --

10 MEMBER WALLIS: Do you take credit for  
11 that?

12 MR. BETTI: We do take the credit for the  
13 maldistribution.

14 MEMBER WALLIS: Because that is an  
15 experiment?

16 MR. BETTI: That is an experiment.

17 MEMBER WALLIS: So you're not really using  
18 this NUREG correlation? You're using the experiment?

19 MR. BETTI: Correct.

20 DR. BANERJEE: And the experiment is a  
21 single strainer, not for a stack.

22 MEMBER WALLIS: An experiment assumes --  
23 well, then in your experiment you've got nonuniform  
24 distribution. So you've got less head loss than you  
25 would have gotten if you had used the correlation, I

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1 expect, because a correlation assumes uniforms, which  
2 would be more conservative.

3 Anyway, I just don't know how we resolve  
4 this because it seems to be an ongoing discussion  
5 here. And then we have to go on.

6 MR. HOBBS: Well, this is Brian Hobbs.

7 I think keeping in mind the purpose of  
8 this meeting is to discuss the effects of power  
9 uprate, we believe we have a conservative debris  
10 quantity used for our head loss design of our  
11 strainers and that the design criteria are not  
12 affected by power uprate. That's sort of the gist of  
13 our presentation today.

14 MEMBER RANSOM: Has there been any effort  
15 to reduce the debris sources, getting rid of some of  
16 the insulation types in Vermont Yankee?

17 CHAIRMAN DENNING: We had a little bit of  
18 that in the introduction, didn't we?

19 MR. BETTI: Yes, I think that. I mean, we  
20 had some TempMat in there that was temporary  
21 insulation. And that has been replaced with RMI  
22 insulation, one.

23 I think the biggest improvement we had was  
24 -- I mean, the sludge source was primarily as a result  
25 of old paint and problems with paint in our torus.

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1 When we installed the strainers, we blasted.

2 So one of the key issues, real issues,  
3 that you have in strainers is a combination of nukon  
4 and sludge. Those are the two real culprits. And the  
5 nukon alone isn't going to hurt it, if it's nukon and  
6 sludge.

7 And effectively what we do now is we have  
8 programs in place -- and I can let ops. talk to that  
9 -- to keep things extremely clean. And so we're not  
10 going to get a lot of sludge coming out of our  
11 containment in there. And then, two, as witnessed  
12 after 6 years of operation with our new paint in our  
13 torus, we pulled out 75 pounds of debris.

14 So I think that's the key to focus on is  
15 that we would like to get very little head loss. And,  
16 two, we use a conservative amount of nukon transported  
17 to our torus. That's a third safety feature.

18 MR. NICHOLS: Enrico, what you're saying  
19 is that while we still retain those in our design of  
20 the strainer calculation, designed head losses, we  
21 actually improved on that for what would actually  
22 happen in the plant, which provides another set of  
23 margin for what really occurred.

24 MEMBER RANSOM: I had one other question.  
25 On your picture, what is that current open area on the

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1 end?

2 MR. NICHOLS: It's not. It's a closed  
3 area on the end, probably a piece of plywood,  
4 something that's --

5 MEMBER RANSOM: This is part of the  
6 strainer material closing the end.

7 MR. NICHOLS: Closing the end on our  
8 strainer is a stainless steel plate with stiffeners,  
9 just a solid plate.

10 MEMBER RANSOM: Just a solid plate on the  
11 end?

12 MR. NICHOLS: Solid plate on the end,  
13 right.

14 CHAIRMAN DENNING: Well, thank you very  
15 much. We appreciate your flexibility in being able to  
16 make this presentation on such a quick request. And  
17 we're ready now to move on to the source terms and  
18 radiological consequences.

19 15. SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES

20 MS. HART: Hi. I'm Michelle Hart. I'm  
21 with the NRR staff. I'm a health physicist. And I  
22 had the task of looking at the source terms and  
23 radiological consequences analysis for the Vermont  
24 Yankee extended power uprate.

25 Next slide. I used the EPU review

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1 standard matrix 9 to do my work. And my SEM was put  
2 into that safety evaluation section 2.9.1 and 2.9.2.  
3 For the source terms for the radwaste systems  
4 analysis, the licensee did look at the radiation  
5 sources and the reactor coolant accident for the  
6 constant pressure power uprate conditions and then do  
7 continue to meet the requirements.

8 For the design basis accident radiological  
9 consequences analysis, the licensee submitted a  
10 separate alternative source term amendment request.  
11 And that was reviewed and approved as amendment number  
12 223 on March 29th of 2005. The dose analyses did  
13 assume the proposed EPU conditions, 1950 megawatts  
14 thermal, which is 102 percent of the operated power.

15 They followed the regulatory guidance  
16 unless they justified it. And all the design basis  
17 accidents do meet 10 CFR 50.67 criteria and the more  
18 specific criteria in the standard review plan.

19 MEMBER WALLIS: They meet the criteria,  
20 but the margin has gone down presumably because of the  
21 bigger source term.

22 MS. HART: It's hard to make that one  
23 criterion. They did do some additional things. They  
24 took some additional credit for removal in the  
25 containment as well when they went to the new source

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1 term.

2 MEMBER WALLIS: So they used a different  
3 calculation procedure than before?

4 MS. HART: Yes, right. Right. And if you  
5 look at the next slide, this is the changes that they  
6 made in that alternative source term amendment. Most  
7 of the changes were made in the LOCA.

8 For BWRs, the standard assumption is that  
9 it is the tech spec leaking rate from the drywell for  
10 the entire duration of the accident. They justified  
11 reducing that after 24 hours to half of that leakage  
12 rate.

13 MEMBER KRESS: Isn't that what they always  
14 do?

15 MS. HART: BWRs.

16 MEMBER KRESS: BWRs?

17 MS. HART: That's not a standard, no.

18 MEMBER KRESS: PWRs are.

19 MS. HART: PWRs, yes. Yes, PWRs, that's  
20 a standard assumption, the reduction.

21 MEMBER KRESS: It's because you get a  
22 lower pressure.

23 MS. HART: Right, right. And that's how  
24 they justified this reduction for the BWR. They also  
25 took credit for the use of the SLC system, running

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1 that after the accident to keep the pH level in the  
2 suppression pool above seven so that you would not  
3 have re-evolution.

4 MR. CARUSO: So that means that there is  
5 boric accident released into the containment following  
6 a Loca as part of the design mitigation.

7 MS. HART: That is correct. That is a  
8 change that they made in their alternative source term  
9 amendment.

10 MEMBER WALLIS: So they do change the  
11 suppression pool pH, but doesn't the SLC system have  
12 a low pH? I thought someone set a -- it's an acid,  
13 isn't it, a low pH?

14 MS. HART: It's an acid.

15 MEMBER KRESS: Yes. You generally the  
16 suppression pool --

17 MEMBER WALLIS: There's no buffer.

18 MEMBER KRESS: -- pH to be higher. That  
19 could be basic or neutral. I don't understand this.

20 CHAIRMAN DENNING: Yes. But that's also  
21 surprising. Do you mean in any LOCA they're now going  
22 to operate the SLC system?

23 MS. HART: That's correct.

24 MEMBER WALLIS: So we could have chemical  
25 effects in the pool that we didn't think about before?

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1 MEMBER KRESS: I don't know what chemicals  
2 are in SLC. I always thought it was boric acid.

3 MS. HART: It's sodium pentaborate.

4 MEMBER KRESS: Sodium pentaborate.

5 MS. HART: Correct, yes, sodium  
6 pentaborate.

7 MEMBER WALLIS: It's a buffering thing?

8 MS. HART: It's a buffer, yes. They're  
9 buffering.

10 MEMBER WALLIS: So it does go to a high  
11 pH, then.

12 MS. HART: It goes above seven.

13 MEMBER WALLIS: Right. So it's not  
14 acidic?

15 MS. HART: It's not acidic.

16 MEMBER WALLIS: So it has all the things  
17 that BWRs have and all the chemical effects that --

18 MEMBER KRESS: Sodium pentaborate is not  
19 what PWRs use, but --

20 MS. HART: No.

21 MEMBER WALLIS: They use something like  
22 that as a buffer.

23 MEMBER KRESS: They use a pH buffer, yes.

24 MEMBER WALLIS: They don't use it for the  
25 boron. They don't use it for the boron. They use a

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1 sodium something for a buffer, but it's boric acid  
2 they use.

3 But wait a minute now. This stuff goes  
4 into the suppression pool with every LOCA?

5 MS. HART: That is what they have assumed,  
6 yes. They have special procedures that if they know  
7 that a LOCA has happened, that they will inject that  
8 within -- I can't recall the exact time, but it was  
9 within a certain time frame. It's I think a couple of  
10 days before they absolutely need to have it to make  
11 sure that they don't have iodine re-evolution.

12 MEMBER WALLIS: And this affects all the  
13 stuff we were talking about half an hour ago.

14 DR. BANERJEE: It depends when it's  
15 injected, I guess.

16 CHAIRMAN DENNING: Let's make sure that  
17 we're not misinterpreting. Is there any  
18 misinterpretation here as to what is happening? Is  
19 indeed in every LOCA now you would operate the SLC  
20 system? Is that a true statement or not?

21 MR. PEREZ: Okay. This is Pedro Perez.

22 Basically the way I look at it, there's  
23 only one design basis LOCA. And with that event,  
24 which is a high release of source term from the core,  
25 we will inject the sodium pentaborate within two hours

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1 to keep the suppression pool pH, of course, the  
2 recirculation, above 7 for 30 days.

3 CHAIRMAN DENNING: Based on what do you  
4 decide that you had a large release of radionuclides?

5 MR. PEREZ: On the drywell high range  
6 monitor readings.

7 CHAIRMAN DENNING: And do you know how  
8 high? I mean, the silliness of what we are getting  
9 ourselves into here is that the reality is in the  
10 large LOCA, you have a trivial release of iodine.

11 And we play this game of design basis  
12 source terms for a certain purpose. And if we're  
13 injecting SLC inappropriately and getting at the  
14 questions of chemical reactions in the suppression  
15 pool and all this kind of stuff just because of a  
16 regulatory conservative inconsistent way that we treat  
17 design basis accidents, we have led ourselves down the  
18 wrong pathway.

19 So it does require in coincidence before  
20 you would operate the SLC an indication of the  
21 substantial amount of iodine release or could it be  
22 just a gap release and we would wind up injecting  
23 something? Is that clear or not?

24 MR. PEREZ: Again, this is Pedro Perez.  
25 The indication would be over 500 rankine

1 per hour in the drywell, which is extremely high  
2 compared to the normal. So you will have a very large  
3 gap release. And basically this is primarily from the  
4 noble gases.

5 CHAIRMAN DENNING: Would a gap release  
6 give you this?

7 MR. PEREZ: Yes, sir.

8 CHAIRMAN DENNING: Yes? It would give you  
9 this? The gap release would give you this?

10 MR. PEREZ: Yes.

11 MEMBER WALLIS: So this happens with quite  
12 a few LOCAs.

13 MR. PEREZ: It will be basically the  
14 design basis source term to assume a significant level  
15 of damage in the fuel itself, starting with the gap  
16 release and then a subsequent overheating of the fuel,  
17 releasing your halogens and more of the radionuclides.

18 MEMBER WALLIS: This is in the design  
19 basis accident?

20 MR. PEREZ: Yes, sir.

21 DR. BANERJEE: How many fuel rods would  
22 need to be damaged? What sort of core damage is  
23 needed?

24 MR. PEREZ: Again, Pedro Perez.

25 The AST application follows regulatory

1 guide 1.103, where you have the prescribed release for  
2 actions and timings. And we're talking about  
3 basically 100 percent of the gas, noble gas,  
4 activities released within I think 30 seconds. The  
5 start is 30 seconds.

6 CHAIRMAN DENNING: All this artificial  
7 design basis accidents calculation that we do, well,  
8 we're not going to solve this problem today. Please  
9 continue.

10 MS. HART: In addition, they took credit  
11 for iodine removal by the drywell sprays, both for the  
12 particulate and the elemental form of iodine, and also  
13 took credit for iodine deposition in the main steam  
14 lines for any leakage that would go past the main  
15 steam line isolation valves.

16 CHAIRMAN DENNING: This is all --

17 MEMBER WALLIS: Part of those sprays that  
18 bring down the pressure?

19 MS. HART: That's correct.

20 MEMBER WALLIS: I thought they needed it  
21 for MPSE.

22 MR. PEREZ: Based on the iodine.

23 MEMBER WALLIS: It's another one of these  
24 glitches in the design basis accident definition or  
25 something?

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1 MS. HART: I'm not sure I understand the  
2 question.

3 MEMBER WALLIS: Drywell is best operated  
4 when you calculate these other calculations we have  
5 seen for the pool temperature?

6 MR. PEREZ: Yes. This is Pedro Perez.

7 Yes. The same drywell sprays that are  
8 credited for removing the iodine particulates, these  
9 are the same that assumed that have the maximum  
10 condensation, if you would, of the condensibles that  
11 minimize the pressure that's credited in the  
12 containment overpressure calculation.

13 CHAIRMAN DENNING: Continue.

14 MS. HART: Yes. They also continued to --  
15 they looked at the rest of the design basis accidents  
16 that do apply to BWRs, the main steam line break, the  
17 fuel-handling accident, and the control rod drop  
18 accident. For none of the accidents did they assume  
19 control room isolation. They assumed just normal  
20 intake as they are unfiltered in leakage.

21 Next slide. To go further into the SLC  
22 system pH control to credit the use of the system,  
23 they discussed the reliability of the system. They  
24 also discussed the procedures, compensatory measures,  
25 and training. And there was also a review done of the

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1 suppression pool buffering adequacy by injecting that  
2 sodium pentaborate.

3 And for the new justification for the  
4 crediting iodine deposition in the main steam piping  
5 and in the condenser, they looked at the seismic rug  
6 in this, the alternate leakage treatment pathway. And  
7 they also discussed and we found acceptable elemental  
8 and particulate iodine removal methodologies and  
9 assumptions.

10 That concludes my presentation. Do you  
11 have any further questions?

12 CHAIRMAN DENNING: No. Thank you very  
13 much.

14 16. HEALTH PHYSICS

15 MR. PEDERSEN: My name is Roger Pedersen.  
16 I'm a senior health physicist in the former Plant  
17 Support Branch, the former Division of Inspection  
18 Program Management, Office of Nuclear Reactor  
19 Regulation.

20 I looked at the health physics aspects of  
21 the Vermont Yankee EPU. Most of the health physics  
22 issues associated with extended power uprate were  
23 addressed and closed out in the review of the GE  
24 topical report. There are a few specific examples  
25 which were the topic of my review.

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1           The stroke of my review focused on first  
2 verifying that the conclusions in the topical report  
3 were still applicable to the Vermont Yankee  
4 application and then focusing on those areas where the  
5 increasing source term, particularly N-16 gammas in  
6 the steam side of the plant and some gas issues, might  
7 impact both occupational doses and public doses of the  
8 EPU.

9           Well, there's also an issue with regard to  
10 post-accident access to the plant, the lessons learned  
11 from Three Mile Island, item 2.B.2 if you're familiar  
12 with the lessons learned task force designation.

13           The topical review, as I said, addressed  
14 the adequacy of the shield design for typical plants.  
15 It does acknowledge that certain areas may have higher  
16 dose rates depending on the plant-specific design.

17           So part of my review was to verify that  
18 the radiation zoning designations -- it's in the  
19 current FSAR of the plant -- did not change. And the  
20 licensee did verify that.

21           So that indicates that the dose ranges in  
22 those normally occupied spaces of the plant during  
23 normal operation are not significantly impacted.

24           CHAIRMAN DENNING:     What are your  
25 assumptions as far as what basically the source term

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1 is under normal operation conditions? Is it assumed  
2 that it's proportional to the power?

3 MR. PEDERSEN: Yes. That was the  
4 assumption. As a first approximation in most of the  
5 areas, there are some cases where that is not true,  
6 particularly with N-16 on the --

7 CHAIRMAN DENNING: Yes. You're going to  
8 talk about N-16 a little bit more?

9 MR. PEDERSEN: Yes.

10 CHAIRMAN DENNING: Okay.

11 MR. PEDERSEN: The design basis accident  
12 or the post-accident access to vital areas of the  
13 plant issue was actually addressed by the licensee in  
14 the AST submittal that Michelle spoke of a minute ago.

15 In switching to the alternate source term,  
16 the licensee included the post-accident access to  
17 vital area evaluation with the other design basis  
18 accidents. And they evaluated the doses to  
19 individuals doing missions out in the plant to  
20 mitigate the course of an accident at the EPU power  
21 rate, even though this was a pre-EPU analysis that  
22 they did. And they demonstrated that they do meet  
23 those criteria in the 737 2.B.2. That issue was  
24 included.

25 In terms of public doses, the significant

1 issue that we focused on was the compliance with 40  
2 CFR 190, which is an EPA regulation. It's also  
3 referenced in 10 CFR 2013.01E, which is a design basis  
4 of 25 millirem per year to a member of the public.  
5 It's a public dose constraint, if you will, as opposed  
6 to the 100 millirem per year dose limit that we have  
7 in 10 CFR part 20.

8 The N-16 issue, the elevated N-16 from the  
9 power uprate, does impact that dose off site,  
10 particularly from sky shine off the turbine  
11 components, the turbine building, condenser, and steam  
12 line in the turbine building.

13 You look like you had a question. I'm  
14 sorry.

15 CHAIRMAN DENNING: Yes. As far as is most  
16 of the dose coming from noble gas release from --

17 MR. PEDERSEN: No. At this point it's  
18 N-16.

19 CHAIRMAN DENNING: It really is N-16, --

20 MR. PEDERSEN: Yes.

21 CHAIRMAN DENNING: -- not a sky shine kind  
22 of thing?

23 MR. PEDERSEN: Yes. Even though the  
24 concentration of N-16 coming out of the reactor,  
25 starting into the steam line, the concentration is

1 constant, there is a 20 percent increase in production  
2 plus a 20 percent increase in steam flow. So the  
3 concentration is constant.

4 There is actually a reduction in the decay  
5 time. The 20 percent higher flow rate results in the  
6 N-16 getting to the turbulent components faster.

7 So the 7.2-second half-life comes into  
8 effect. So there is actually more than a 20 percent  
9 increase in the N-16 decaying in the turbine and the  
10 condenser. The shine, the scatter off of the  
11 atmosphere above the plant to the dose receptor off  
12 site, sees that, sees that increase.

13 I have to apologize for this slide.  
14 There's an error in it. If you would ignore the  
15 20.2-millirem per year there? That is an erroneous  
16 number. It actually included the non-N-16 direct  
17 shine off to the off site, most limiting off-site  
18 location twice. It double added that.

19 So if you would just ignore that number  
20 and read that slide or the third bullet to that slide  
21 with the pre-EPU dose is 15 millirem per year, 13.4,  
22 the resulting from N-16, increases to not 20.2 but  
23 18.6 millirem per year from radiation and sky shine.  
24 There was a revision to the slide that didn't get  
25 fully implemented, and I apologize for that.

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1 MEMBER RANSOM: It increases to what?

2 MR. PEDERSEN: 18.6 is the total.

3 MEMBER RANSOM: 18.6 is total, yes.

4 MR. PEDERSEN: From total direct radiation  
5 and sky shine to the most limiting location off site,  
6 not the 20.2. That was an error. In addition to the  
7 N-16, there is some shine from other components on  
8 site, rad waste tanks and --

9 MR. CARUSO: Can I just ask, 15 was  
10 composed of 13.4 from N-16 shine plus 1.6 of  
11 everything else?

12 MR. PEDERSEN: The 15 millirem per year is  
13 the current annual off-site dose from the direct  
14 radiation and shine, N-16 shine. 13.4 of that  
15 currently is from N-16 shine.

16 MR. CARUSO: Okay.

17 MR. PEDERSEN: So that 15 will increase to  
18 18.6 millirem per year.

19 MR. CARUSO: And of the 18.6, how much is

20 --

21 MR. PEDERSEN: 16.9.

22 MR. CARUSO: 16.9.

23 MEMBER KRESS: Is that calculated at the  
24 nearest point on the boundary?

25 MR. PEDERSEN: The most limiting, yes, the

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1 most limiting point on the boundary. Now,  
2 interestingly enough, 40 CFR 190, the EPA regulation  
3 is actually to an actual member of the public.

4 MEMBER KRESS: Which may or may not be  
5 that point.

6 MR. PEDERSEN: May or may not be that  
7 point. But the licensee didn't take credit for that  
8 in their calculation.

9 MEMBER WALLIS: Where is this member of  
10 the public?

11 MR. PEDERSEN: Excuse me? Yes, I can't  
12 point it out on a map, but it's the most limiting  
13 location according to the analyses the --

14 MEMBER WALLIS: Trying to get highest  
15 dose?

16 MR. PEDERSEN: It is my understanding it  
17 is not too far from where the nearest member of the  
18 public actually lives. There is a residence right on  
19 --

20 MEMBER RANSOM: And that's all year?  
21 There's no fraction --

22 MR. PEDERSEN: Yes. They didn't take any  
23 residency factor into consideration for that dose  
24 factor.

25 MEMBER SIEBER: It's on the

1 owner-controlled area fencepost. That's the closest  
2 point.

3 MR. PEDERSEN: Yes. Now, I have to point  
4 out that these calculations are based on the  
5 licensee's current off-site dose calculation manual  
6 methodology. It's a calculational dose, as opposed to  
7 a monitored dose, a measured dose.

8 That methodology is based on an empirical  
9 relationship that they determined by measuring the  
10 dose at this location and correlating that to the  
11 steam line ramp monitor readings. So the dose is a  
12 calculation that uses the steam line rad monitor  
13 reading as a basis for running through the algorithm  
14 of the dose.

15 Now, subsequent to me finishing my review  
16 and writing the safety evaluation, there has been a  
17 question raised about that methodology. And we, the  
18 NRC region I inspection program, are looking at their  
19 off-site dose calculation manual closer.

20 There was an on-site review two weeks ago.  
21 And there are a couple of unanswered questions at this  
22 point. So there should be a star next to this. We  
23 didn't open an item here. We don't have an unresolved  
24 issue in the review at this point, but that's pending  
25 the licensee being able to resolve the open questions

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1 from the inspection that is outstanding at this point.

2 MEMBER SIEBER: Did you look at items that  
3 are part of post-accident radiological conditions,  
4 like post-accident sampling kinds of things, leakage  
5 from equipment under recirculation?

6 MR. PEDERSEN: The post-accident access,  
7 the 2.B.2 items, --

8 MEMBER SIEBER: Yes.

9 MR. PEDERSEN: -- those vital areas that  
10 are defined --

11 MEMBER SIEBER: Right.

12 MR. PEDERSEN: -- in NUREG 0737, --

13 MEMBER SIEBER: Right.

14 MR. PEDERSEN: -- yes, those are the  
15 locations that an operator needs to access in the  
16 plant to mitigate the course of the accident.

17 MEMBER SIEBER: And they should be  
18 accessible?

19 MR. PEDERSEN: They should be accessible.  
20 And those criteria --

21 MEMBER SIEBER: Are they?

22 MR. PEDERSEN: -- it refers to GDC 19,  
23 which this is not a GDC plant. So there's a GDC 11  
24 that comes in there. But yes, they demonstrated a  
25 level -- they calculated the 11 vital areas that they

1 identified are accessible within the dose criteria 737  
2 2.B.2.

3 MEMBER SIEBER: Okay. Thank you.

4 MR. PEDERSEN: My final slide is the  
5 conclusion that's in the safety evaluation. The staff  
6 concludes that the EPU proposal meets the requirements  
7 in 10 CFR 20. And, again, that's with an asterisk:  
8 assuming that there is a satisfactory resolution to  
9 the outstanding questions concerning the off-site dose  
10 calculation manual, 10 CFR 50, appendix I, and NUREG  
11 0737, item 2.B.2.

12 The staff finds that the licensee's  
13 proposal is acceptable with respect to radiation  
14 protection and ensuring that occupational radiation  
15 exposure will be maintained as low as reasonably  
16 achievable.

17 CHAIRMAN DENNING: Thank you. Break time.  
18 What we're going to do, we're going to have five extra  
19 minutes. So 2:45

20 (Whereupon, the foregoing matter went off  
21 the record at 2:26 p.m. and went back on  
22 the record at 2:46 p.m.)

23 CHAIRMAN DENNING: And we're now going to  
24 get into one of my favorite subjects, probabilistic  
25 safety analysis.

1 MR. NICHOLS: Today to make the  
2 presentation on probabilistic safety assessment for  
3 the extended power uprate, we have Mr. Vincent  
4 Anderson, manager of the Risk and Reliability Group at  
5 Erin Engineering and Jerry Head, the manager of  
6 Nuclear Engineering Analysis for Entergy Nuclear,  
7 Northeast.

8 Vincent.

9 MR. ANDERSON: Good afternoon. I'll be  
10 giving an overview of the risk assessment for the  
11 VYEPU.

12 The approach taken to the VYEPU is the  
13 same as done in past EPU risk assessments that you may  
14 have seen, and the results are the same, very similar  
15 to the past studies.

16 This first slide gives an overview of the  
17 status of the VYPRA program. The internal events risk  
18 models at Vermont Yankee are a Level 1 and a Level 2  
19 PSA, Level 1, as you know, being core damage  
20 frequency, Level 2 release frequency.

21 The external events analyses at VY were  
22 developed as part of the individual plant examination  
23 of external events in 1998, and as you know, cover  
24 internal fires and seismic and other external hazards.  
25 Internal fires were done with the EPRI FIVE

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1 methodology, and seismic was done with the EPRI  
2 seismic margins methodology, and the other external  
3 hazards were done as a comparison against the NRC  
4 standard review plan with the IPEEE guidance of NUREG  
5 1335, I believe.

6 CHAIRMAN DENNING: Are there any intents  
7 to upgrade the internal fire's PRA?

8 MR. ANDERSON: Jerry would probably have  
9 to answer that.

10 CHAIRMAN DENNING: Yeah.

11 MR. HEAD: Entergy as a corporation is  
12 looking right now in the 0805 potential that's coming  
13 out. We're looking at that across the fleet and  
14 trying to make a determination which direction we'll  
15 go. I can't give you an answer right now how we're  
16 going to land as far as which plants we're going to  
17 take down that path and what that timetable will be,  
18 but I think those decisions are due by the end of the  
19 year.

20 MR. ANDERSON: As you know, the NRC's  
21 phased approach to risk regulation, utilities are now  
22 considering the other aspects of the risk profile and  
23 how they're going to proceed on them in the next  
24 number of years.

25 So next slide.

1           So the PSA that was used for the risk  
2 assessment is an up to date PSA. It reflects the  
3 current plant configuration. There was an NEI peer  
4 review performed for the VYPRA in 2000. All the A and  
5 B facts and observations have been resolved. Those  
6 are what are termed the higher priority facts and  
7 observations.

8           The VYPSA is maintained and routinely  
9 updated. It has been updated, I believe, five or six  
10 times since the IPE submittal. The scheduled updates  
11 are performed on a two cycle schedule per procedure.

12           Next slide.

13           CHAIRMAN DENNING: Is the PSA used for  
14 operational purposes? Do you have it basically on  
15 line, and do you use it when you make changes in  
16 configurations?

17           MR. HEAD: That's correct. All of the  
18 configuration risk management practices that we have  
19 for normal operational and maintenance activities are  
20 covered using this model.

21           MR. ANDERSON: The big ticket items for  
22 the impacts due to EPU on the PSA come from hardware  
23 changes that are made, procedural changes, plant  
24 configuration changes and obviously the increased  
25 power level.

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1           Comparing the modifications of the VYEPU  
2 with the PSA models, these are essentially the  
3 impacts. There are no new accident sequences  
4 identified. The EPU does nothing that would change  
5 the way accident sequences are modeled or how they  
6 progress other than certain timing issues.

7           There are no significant impacts on the  
8 following: initiating event frequencies. The turbine  
9 trip initiating event frequency was the only one that  
10 was adjusted to predict or to bound any future  
11 increase in turbine trip frequency to running the  
12 third feedwater pump. That's just a predicted  
13 adjustment in the PSA model. Obviously future  
14 operating experience will actually determine what the  
15 real frequency of a turbine trip is.

16           Of the success criteria in the PSA, there  
17 was only one that required modification due to the  
18 EPU, and that was the requirement of an additional  
19 safety valve for ATWS over pressure protection.

20           The hardware changes as part of the EPU  
21 resulted in no impacts on the PSA. They are typically  
22 like for like replacements or enhanced components,  
23 newer components, and in fact, the future may hold  
24 that they operate more reliably than the previous  
25 equipment did.

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1           And the procedural changes also did not  
2 warrant any changes to the PSA. Any changes to  
3 procedures were so minor that they had no impact on  
4 human error probabilities. The procedures are the  
5 same. They just are minor changes to reflect minor  
6 set point changes, et cetera.

7           CHAIRMAN DENNING: But that doesn't mean  
8 that the HRA probabilities haven't been modified.

9           MR. ANDERSON: That is a correct  
10 statement.

11           The other impact is due to the changes in  
12 timing due to the increased decay heat load on post  
13 initiator operator actions. Post initiator operator  
14 actions are those obviously that are performed in  
15 response to an initiator. The PSA obviously has pre-  
16 initiator operator errors, but those are obviously not  
17 impacted by the EPU.

18           There's approximately 60 or so post  
19 initiator actions in the PRA, and those were  
20 investigated for changes, their probabilities, due to  
21 decay heat load changes, and obviously not all of them  
22 are impacted by changes in decay heat load. Only some  
23 fraction of them are.

24           MEMBER WALLIS: Now, these, you say slight  
25 decrease in time.

1 MR. ANDERSON: Yes.

2 MEMBER WALLIS: And then I went to this  
3 GENEDC 3309TP, and sometimes for certain actions the  
4 time changes by what looks like a small amount, but  
5 the probability, the human error probability, goes up  
6 much more than you would expect for that small time  
7 increase. It must have something to do with ---

8 MR. ANDERSON: That could be true.

9 MEMBER WALLIS: -- how long it takes to do  
10 the action or something.

11 MR. ANDERSON: Yes, that is true.

12 MEMBER WALLIS: There are some remarkable  
13 changes of where the time changes by 20 percent, but  
14 the error goes up like three times.

15 MR. ANDERSON: Yes, right. Yep, yep,  
16 you're probably getting to those faster actions.

17 MEMBER WALLIS: Right.

18 MR. ANDERSON: A small change in time --

19 MEMBER WALLIS: The fact that you have a  
20 slight decrease in time doesn't mean that it's a  
21 slight change in the probability of error.

22 MR. ANDERSON: Correct., yep, yep.

23 MEMBER WALLIS: Okay.

24 MR. ANDERSON: Yep, that is a true  
25 statement. Some of these --

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1 MEMBER RANSOM: The probabilities have  
2 been taken into account then?

3 MEMBER WALLIS: He's going to get to it,  
4 I suppose.

5 MR. ANDERSON: What was that question? Do  
6 you want me to --

7 MEMBER RANSOM: Just whether or not the  
8 change in the probability in the occurrence had been  
9 factored in.

10 MR. ANDERSON: Oh, definitely, yes.

11 MEMBER WALLIS: Because it's part of the  
12 PRA, isn't it?

13 MR. ANDERSON: Yes, yes. The human error  
14 probabilities were recalculated based on the changes  
15 in the timing.

16 MEMBER KRESS: So one times ten to the  
17 minus three is three times ten to the minus three.

18 MR. ANDERSON: Right, or an action that  
19 was -- a one percent failure could go up to a five  
20 percent.

21 MEMBER WALLIS: Is this GE document the  
22 basis for your probabilities that you use for human  
23 errors?

24 MR. ANDERSON: I must say I don't know  
25 what GE document you're referring to.

1 MEMBER WALLIS: It's one of the things  
2 that you guys put on file for us to read.

3 MR. HEAD: I believe that the GE document  
4 and the PSA model both use the same root document for  
5 a source for those numbers. I believe those human  
6 error probabilities were calculated as part of the PSA  
7 update and then lifted and put in the GE document, I  
8 believe.

9 MEMBER WALLIS: It says that they're  
10 referring to a general -- so CPPU? It's not specific  
11 to Vermont Yankee.

12 MR. NICHOLS: I believe that is our  
13 submittal document.

14 MR. NICHOLS: Oh, is that it? Okay.

15 MR. ANDERSON: So that would be plant  
16 specific numbers. It's plant specific numbers.

17 MEMBER WALLIS: You have plant specific,  
18 yeah.

19 MR. ANDERSON: Yeah, there's an EPU risk  
20 assessment that includes human error probability  
21 changes. It's a thick document.

22 MEMBER WALLIS: I was surprised that I  
23 couldn't -- some of these human error probabilities  
24 were as large as 73 percent. Does that seem right?

25 MR. ANDERSON: Very few of them would be

1 that, but yes.

2 MEMBER WALLIS: Very few, but there is one  
3 in that table --

4 MR. ANDERSON: Yes.

5 MEMBER WALLIS: -- which is 73 percent,  
6 which seems --

7 MR. ANDERSON: Yeah, I know the one. When  
8 you mentioned it earlier, that's reopening the MSIVs  
9 during an ATWS scenario.

10 MEMBER WALLIS: That's right.

11 MR. ANDERSON: Yeah. The VYHRA, human  
12 reliability analysis, was updated in 2000 to include  
13 operator interviews, and so the operators were  
14 interviewed for all, not all, but a large fraction of  
15 the actions, and I believe that action requires an  
16 estimated 15 minutes to complete it.

17 MEMBER WALLIS: That's why. They don't  
18 have much more margin.

19 MR. ANDERSON: No, you don't have much  
20 margin, and it's a complex action. It's installing  
21 jumpers, and then you actually have to reopen the  
22 MSIVs, equalize them on both sides, yeah.

23 CHAIRMAN DENNING: But ATWS is a low  
24 probability event. So that even though --

25 MR. ANDERSON: Exactly.

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1 CHAIRMAN DENNING: -- it's a high human  
2 error here --

3 MR. ANDERSON: Right, exactly.

4 CHAIRMAN DENNING: -- it doesn't make that  
5 much difference to the rest.

6 MR. ANDERSON: That is a correct  
7 statement. We are talking about changes in the short  
8 time frame actions for ATWS, and those are where the  
9 actions, the human error probabilities are more  
10 influenced compared to others, but in the grand scheme  
11 of things, ATWS is six or seven percent of the overall  
12 CEF profile. So you're getting minor changes in your  
13 overall CEF profile because ATWS is such a low  
14 frequency accident scenario.

15 And I guess we'll go to the next slide.

16 For example, since we're talking about  
17 ATWS, I put up a few of the ATWS actions right here,  
18 and you've seen them before. These are the faster  
19 moving operator actions. They're not necessarily the  
20 dominant actions in a PRA. Obviously the slick one  
21 would be the more important one of the ATWS actions  
22 here, but in the grand picture of actions in the PRA,  
23 that's probably only maybe the fifth or sixth most  
24 important action in the PRA. The others are probably  
25 way down there on the list.

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1           The timing, as you'll see, dropped 45  
2 seconds or so out of five or six minutes, and that's  
3 the allowable action time that the PSA determines  
4 based on thermal hydraulic runs and assumed Q times  
5 and end times of what the PSAs are concerned with, and  
6 the time that the operator actually has to perform  
7 that action is well within that.

8           For example, inhibiting ADS maybe a minute  
9 and a half to actually do that with the feedback back  
10 and forth among the operators, and yet he still has  
11 over five minutes to do it.

12           CHAIRMAN DENNING: Yes. Now, in coming up  
13 with the realistic estimate for the time to do that  
14 action, how is that really done?

15           MR. ANDERSON: That goes back to the 2000  
16 human reliability analysis update and the interviews  
17 with the operators and training staff at that time.  
18 So PRA engineers would sit down with operating staff  
19 over the course of a couple of days and go through  
20 scenarios and EOPs and ask them are they trained.  
21 When was the last time they trained on this? Are they  
22 familiar with this action? How long does it take to  
23 do it? Is it a priority for you? All of those sorts  
24 of things.

25           CHAIRMAN DENNING: That was mostly though

1 in interviews as opposed to, again, simulator  
2 demonstration?

3 MR. ANDERSON: Mostly interviews, but I  
4 believe -- and I may be stretching it here by telling  
5 you -- I believe simulator observations were performed  
6 as well as part of that, but I do not know that answer  
7 right now.

8 MR. HEAD: Our typical process within  
9 Entergy is to look at the simulator evaluations of  
10 various events. As part of that process on the  
11 update, we've not --

12 MR. TABONE: Excuse me. This is Chris  
13 Tabone from Entergy.

14 These are some of the ones that are listed  
15 there. Those quicker ones during the ATWS were the  
16 ones we did do during -- in the simulator with a crew  
17 and a stopwatch.

18 MEMBER WALLIS: What sort of probability  
19 did you come up with for these?

20 MR. TABONE: These guys are on the order  
21 of one to two percent failure rates. They both depend  
22 on the complexity of the action and the timing. I've  
23 got numbers scribbled down here.

24 For example, initiation of SLICK is about  
25 a 5E to the minus two failure rate that goes up to

1 about an 8E to the minus --

2 MEMBER WALLIS: So it's one in 20 or  
3 something.

4 MR. TABONE: Yeah, it's one of those  
5 things, those type of numbers for the fast moving  
6 actions.

7 MEMBER WALLIS: And this is something that  
8 says realizes he has an ATWS. Is this an action?

9 MR. TABONE: That is part of the  
10 calculation.

11 MEMBER WALLIS: He has to realize he's got  
12 one before he does any of these things.

13 MR. ANDERSON: Right. The human  
14 reliability analysis typically divides up a  
15 recognition that there is an abnormal event. The  
16 diagnosis time frame, then the execution, and then  
17 uses a Gaussian distribution to come up with the  
18 likelihood that he completes all of that within his  
19 five minutes or 15 minute time frame.

20 Next slide.

21 MEMBER WALLIS: So if it's a clean ATWS,  
22 he's probably okay. If it's something unusual about  
23 it, and one problem going back to TMI was that there  
24 were two things wrong. The symptoms got sort of mixed  
25 up.

1 MR. ANDERSON: Right.

2 MEMBER WALLIS: And that's where you worry  
3 about something here. If it's straightforward ATWS,  
4 that's probably okay, but if it's something else  
5 happens to be going on at the same time, then it gets  
6 confused.

7 MR. ANDERSON: That is true, and the  
8 methodology that VY uses, which is called EPRI 6560L,  
9 it handles that on a broader level by assigning us  
10 stress factors.

11 There are other methodologies that  
12 actually get into very fine details of what you  
13 described. What do the procedures look like? What do  
14 the indications look like? Are there double "not"  
15 statements, all that sort of thing?

16 The methodology for the EPU was primarily  
17 the quantitative risk assessment of the Level 1 and  
18 Level 2 internal events, and the Level 2 being the  
19 LERF methodology, the LERF risk metric.

20 Have you got a question?

21 MEMBER RANSOM: No, I'll ask it the next  
22 slide.

23 MR. ANDERSON: And then the other two  
24 aspects were external events and shutdown events were  
25 handled on a qualitative basis by looking at the

1 results of the IPEEE, looking at the conclusions for  
2 fire, for example, looking at the dominant sequences  
3 for fire and making an assessment of how EPU would  
4 impact those.

5 For example, fire is primarily dominated  
6 by fire induced equipment failure combinations and  
7 less so by any changes in operator actions and the  
8 same with seismic. It's overwhelmingly dominated by  
9 past industry studies, by seismic induced failures.  
10 Random and human failures are a small percentage of  
11 the seismic risk profile.

12 And then shutdown events is primarily  
13 impacted by the changes in the boiling time of the  
14 flooded up levels, and those are already long times of  
15 operator actions such that any changes of ten percent  
16 or 15 percent over the course of six hours or ten  
17 hours doesn't make any quantifiable change to a human  
18 error probability calculation.

19 So the next slide.

20 And these are the final conclusions. The  
21 delta DCF was calculated three to the minus seven in  
22 the very small risk range of reg. guide 117, and LERF  
23 was right at the border of very small and small and  
24 delta LERF of 1E to the minus seven. And that's --

25 MEMBER WALLIS: A change in two weeks?

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1 MR. ANDERSON: I hope not.

2 MEMBER WALLIS: Two weeks ago the numbers  
3 were bigger.

4 MR. ANDERSON: Oh, was that the  
5 containment over pressure estimate?

6 MEMBER WALLIS: I don't -- oh, maybe  
7 that's where it is. Maybe I'm confused.

8 MR. ANDERSON: And that's unfortunate  
9 because the containment over pressure --

10 MEMBER WALLIS: Bigger numbers than these.

11 MR. ANDERSON: Well, yeah. Well, if we  
12 were to do it without being forced down the path of  
13 coming up with one, the delta risk for containment  
14 over pressure probably would be zero.

15 MEMBER WALLIS: Now, does your PRA then  
16 include that sequence? It includes the probabilistic  
17 analysis of the temperature of the pool and the  
18 probabilistic analysis of the failure of containment  
19 with the small hull and --

20 MR. ANDERSON: No.

21 MEMBER WALLIS: -- NPSA test not in the --

22 MR. ANDERSON: That is -- that is not in  
23 this risk assessment.

24 MEMBER WALLIS: It's not in this.

25 MR. ANDERSON: If we were to put it in

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1 there, we would put it in here on a less bounding  
2 approach than we did three weeks ago, yes, and then it  
3 wouldn't change these numbers.

4 MEMBER WALLIS: But it would change the  
5 other one because for the other ones --

6 MR. ANDERSON: Yes.

7 MEMBER WALLIS: -- you had to assume  
8 something.

9 MR. ANDERSON: Yeah, and we just went with  
10 what people wanted to hear. Throw it in there and  
11 assume it goes away. NPSH goes away if you've got a  
12 hole, but you require a lot of things rather than just  
13 a hole.

14 MEMBER RANSOM: Now, these numbers include  
15 credit for containment over pressure, or do not?

16 CHAIRMAN DENNING: They're realistic.

17 MR. ANDERSON: This is realistic analysis.  
18 so yes. So the thermal hydraulic calculations here do  
19 calculate what the containment pressure is, but the  
20 issue about containment over pressure on NPSH, those  
21 scenarios, that threshold was never met because you  
22 only meet that limiting NPSH in design basis  
23 assumptions of the 85 degree pool temperature, 102  
24 power, two sigma decay heat, all that stuff, which the  
25 realistic PRA doesn't do that.

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1 So we never get to that, needing that  
2 requirement for --

3 MEMBER WALLIS: You never get to it. I  
4 thought there would some probability of getting to it.

5 MR. ANDERSON: Yep, yep. There's  
6 probability, yeah. If we would have to --

7 MEMBER WALLIS: You folks said this  
8 business about if you were realistic the pool  
9 temperature is so much lower.

10 MR. ANDERSON: Right.

11 MEMBER WALLIS: And so on, but there must  
12 be some probability of --

13 MR. ANDERSON: There probably is. We  
14 could probably look at the --

15 MEMBER WALLIS: So there's probably some  
16 finite probability.

17 MR. ANDERSON: There's probably some  
18 finite little hair, exactly. That's a true statement,  
19 and we would have --

20 MEMBER KRESS: You would have to have a  
21 pretty sophisticated uncertainty analysis.

22 MR. ANDERSON: Not to throw out a quick  
23 number, but I'll throw out. It's probably E to the  
24 minus nine, E to the minus eight sequence, you know.

25 MEMBER KRESS: Are you talking probability

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1 or frequency?

2 MR. ANDERSON: Frequency of an accident,  
3 I guess, you know, yeah.

4 MEMBER WALLIS: You'd have the hottest day  
5 in Vermont in two centuries or something.

6 MR. ANDERSON: Yeah, you'd have to have  
7 that. You'd have to be running at 102 percent power.  
8 We'd have to have the pool at its minimum tech. spec.  
9 level, all those things together, and then have to  
10 have the accident in question.

11 MEMBER WALLIS: But the pool never gets  
12 anywhere near that temperature when you're starting.  
13 It never gets up to 90 degrees or whatever it is when  
14 you're starting, before anything else.

15 MR. ANDERSON: Yeah, my guess would be  
16 that's a true statement, but I don't know. Chris, do  
17 you have anything?

18 It probably never got to --

19 MEMBER WALLIS: Have they ever got to 90  
20 degree full temperature?

21 MEMBER SIEBER: Well, you have to shut  
22 down.

23 MEMBER WALLIS: Right.

24 MR. WAMSER: During certain system  
25 surveillances, operational testing of the high

1 pressure coolant injection and the reactor core  
2 coolant, those systems which are quarterly tests do  
3 put us above the 90 degree range, but we have short  
4 duration allowed for that.

5 MR. ANDERSON: Right, for that short  
6 period.

7 MEMBER WALLIS: In normal operation it  
8 doesn't happen.

9 MR. ANDERSON: Absolutely not.

10 CHAIRMAN DENNING: Do you have any leaking  
11 SRVs?

12 MR. WAMSER: No, and we have no recent  
13 history of leaking SRVs at Vermont Yankee.

14 MEMBER WALLIS: And if you did, you'd fix  
15 it.

16 MR. WAMSER: That's correct also.

17 CHAIRMAN DENNING: What's the CDF itself?  
18 I've forgotten.

19 MR. ANDERSON: The CDF was in the range of  
20 7.8E to the minus six per year for the base CDF and  
21 went up to about eight-ish E to the minus six per  
22 year, and that's right in the middle of the pack of  
23 the BWR Mark 1.

24 CHAIRMAN DENNING: I understand why we  
25 look at delta CDF, delta LERF. I mean, that's getting

1 to be part of this risk informed kind of environment  
2 we're in, but there is a difference between looking at  
3 an up rate and delta CDF and LERF and a constant power  
4 where you have changes.

5 The reality is that just the fact of  
6 increasing power by 20 percent increases the inventory  
7 by 20 percent, and means that if our delta CDF had no  
8 change at all, the latent cancer fatality risk  
9 increases by 20 percent, and the early fatality risk  
10 probably increases by more than that, and so I think  
11 we have to be careful not to kid ourselves into  
12 thinking that we get off by looking at these --

13 MR. ANDERSON: Risk metrics.

14 CHAIRMAN DENNING: -- risk metrics that  
15 are poor measures, in some cases poor measures of risk  
16 itself; that there isn't an inherent change in risk  
17 that's associated with the up rate, and I think that  
18 our responsibility is to be sure that that risk still  
19 is an acceptable risk.

20 And of course, we're starting out with a  
21 low risk anyway to start off with.

22 MR. ANDERSON: That is true.

23 CHAIRMAN DENNING: But I think that the  
24 question of how appropriate CDF and LERF are as  
25 measures when we're talking about changes in power

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1 becomes more questionable than it does when we're  
2 talking about changes in configuration at a fixed  
3 power.

4 I have some questions about -- I know it's  
5 illegal for us to now go back and look at the risk  
6 study that was done for the NPSH, but I had questions  
7 about that anyway because I really didn't understand  
8 the two configurations that are discussed, and we look  
9 at the difference between them.

10 But in the words that describe the  
11 configuration, it just didn't make sense to me. Can  
12 you explain that to me again?

13 MR. ANDERSON: Right. I agree. Was it  
14 the word "available"? I think there was some --

15 CHAIRMAN DENNING: Well, I don't know.  
16 You can explain the two configurations, what they  
17 really --

18 MR. ANDERSON: So the base configuration  
19 is the PRA with the EPU adjustments to the PRA. So  
20 we're starting by that.

21 CHAIRMAN DENNING: Right.

22 MR. ANDERSON: And it also has in it  
23 initiation of emergency containment venting defeats  
24 ECCS due to MPSH issues. That's already in the base  
25 model.

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1           The next configuration does one simple  
2 change, and that is the addition of the probability of  
3 containment isolation failure or a preexisting leak,  
4 either one of those, and the probability is determined  
5 in various ways. And that was inserted as a failure  
6 of ECCS in the sequences, and it was done across the  
7 board to all sequences, and there was no additional  
8 mitigation of those probabilities to say really what's  
9 the likelihood that I'm going to be at 90 in the pool  
10 or I'm going to be at whatever.

11           MEMBER WALLIS: Given to all of these ECCS  
12 sequences?

13           MR. ANDERSON: Yes, it was.

14           MEMBER WALLIS: But you don't need --

15           MR. ANDERSON: We don't need it for all  
16 the sequences, yep.

17           MEMBER WALLIS: You only need it for the  
18 big ones.

19           MR. ANDERSON: You only need it for the  
20 big ones, yep.

21           MEMBER WALLIS: So that's vary strange.

22           MR. ANDERSON: Yeah, that is true.

23           MEMBER WALLIS: With the least likely  
24 ones.

25           MR. ANDERSON: Right.

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1 MEMBER WALLIS: So you're erring way on  
2 the way.

3 MR. ANDERSON: Right, and that's the  
4 double edged sword of trying to take bounding  
5 approaches. You know, there's the one side. You take  
6 a bounding approach just to show things aren't  
7 significant with respect to some criteria, but then  
8 you also are forced to start saying that's proper  
9 assessments right there. That's just ridiculous to  
10 assign it to every single sequence, but it was  
11 intended to be a bounding assessment.

12 CHAIRMAN DENNING: Any other questions  
13 about PRA? No?

14 Thank you very much.

15 MEMBER KRESS: Well, I guess I do have  
16 one. Does your PRA have capability of doing parameter  
17 uncertainty, Monte Carlo type?

18 MR. ANDERSON: It does now.

19 MEMBER KRESS: It does?

20 MR. ANDERSON: Yes, and that was performed  
21 for that conservative containment over pressure  
22 assessment. Parametric uncertainty analysis wasn't  
23 performed at the time of this EPU risk assessment a  
24 couple of years ago, but you know, based on knowledge  
25 of what the parametric uncertainty analysis is at VY

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1 and at other plants, the mean propagated uncertainty  
2 probably only changed by ten percent, and it wouldn't  
3 bounce you out of the very small risk category.

4 MEMBER WALLIS: I'm sorry. He left you  
5 off. I'm trying to digest what you just told me.  
6 When you make this change, you sort of say that  
7 there's a containment leak.

8 MR. ANDERSON: Yep.

9 MEMBER WALLIS: And you said it defeats  
10 all of the ECCS?

11 MR. ANDERSON: Yep, yep.

12 MEMBER WALLIS: So none of the ECCS works?

13 MR. ANDERSON: Correct.

14 MEMBER WALLIS: Then why is the effect so  
15 small?

16 MR. ANDERSON: There are other systems.  
17 There's alternating --

18 MEMBER WALLIS: There must be.

19 MR. ANDERSON: Yeah, and there is also --

20 MEMBER WALLIS: So you're really saying we  
21 don't need ECCS at all.

22 MR. ANDERSON: Excuse me. Excuse me. Low  
23 pressure ECCS. Those are also low pressure systems.

24 MEMBER WALLIS: Low pressure, right. It's  
25 the recirc. It's not the high pressure.

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1 MR. ANDERSON: So if we're on high  
2 pressure accident sequences.

3 MEMBER WALLIS: Okay.

4 MR. ANDERSON: Yeah, those are only LPCI  
5 and course --

6 MEMBER WALLIS: It's just a recirc.

7 MR. ANDERSON: Yeah. Thank you.

8 MEMBER WALLIS: You're going to make it  
9 all clear for us now.

10 MR. ANDERSON: Thank you goodness.

11 MR. STUTZKE: Hi. I'm Marty Stutzke from  
12 PRA Licensing Branch A in the Division of Risk  
13 Assessment. That's under our new reorganization. You  
14 see my old affiliation there.

15 Yeah, I find it interesting that all of  
16 the questions are deferred to the PRA, which is always  
17 at the end of the day.

18 In anticipation and maybe some lessons  
19 learned, my next slide is my summary.

20 (Laughter.)

21 MR. STUTZKE: It seems like we always get  
22 cut off, but the basic summary here is that I feel  
23 that the licensee has adequately modeled the risk  
24 impacts in his PRA. The risks are, in fact,  
25 acceptable because the Reg. Guide 1.174 --

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1 MEMBER KRESS: What is your reaction to  
2 Rich's comment that LERF and 1.174 ought not really be  
3 applied to power up rates?

4 MR. STUTZKE: Well, my reaction is we  
5 probably need to look beyond that. I think we need to  
6 be looking at perhaps late sequences, late releases,  
7 as you had indicated, perhaps the use of conditional  
8 containment failure probability.

9 It's true the sorts of issues that you're  
10 dealing with in power up rates aren't well captured by  
11 PRA. It's almost beyond the methodology's capability  
12 to do in any reasonable fashion.

13 MEMBER KRESS: Unless you go to full Level  
14 3.

15 MR. STUTZKE: Unless you go to full Level  
16 3, in which case you would be so overwhelmed by the  
17 uncertainty that you wouldn't show much delta.

18 MEMBER KRESS: Well, maybe you ought to  
19 deal with the uncertainty, too.

20 MR. STUTZKE: Right.

21 MEMBER KRESS: Well, let me ask you  
22 another question about that second bullet. One of the  
23 principles in 1.174, well, two of them; one of them is  
24 that the plant should comply with all of the other  
25 body of regulations when they're dealing with one area

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1 where --

2 MR. STUTZKE: That's correct.

3 MEMBER KRESS: -- you're changing it.

4 How do you know that's true?

5 MR. STUTZKE: That's the traditional  
6 deterministic analysis portion that the other  
7 branches do.

8 MEMBER KRESS: That's the inspection and  
9 the assessment?

10 MR. STUTZKE: Inspections to enforce the  
11 regulations like this. For example electrical-  
12 mechanical, they worry about compliance with  
13 regulation.

14 MEMBER KRESS: So that's what they're  
15 doing when they're --

16 MR. STUTZKE: That's right.

17 MEMBER KRESS: -- going through the SAR.

18 MR. STUTZKE: In other words, out of the  
19 five key principles of risk informed decision making,  
20 my branch looks at number four: what's the impact on  
21 risk?

22 MEMBER KRESS: Right, but the other people  
23 look to see if they meet these other --

24 MR. STUTZKE: Right. We rely on the other  
25 people to do their assessment as well.

1 MEMBER WALLIS: And there is no regulation  
2 about NPSH.

3 MR. STUTZKE: There's no regulation that  
4 prohibits crediting over pressure.

5 MEMBER WALLIS: That's why you say it  
6 conforms to the regulations.

7 MR. STUTZKE: That's right.

8 MEMBER WALLIS: There are reg. guides  
9 though. They're not regulations.

10 MR. STUTZKE: But those aren't  
11 regulations. They are one acceptable way of  
12 complying with regulation.

13 All right. Let me jump to the second  
14 slide to remind you of kind of the game rules of the  
15 risk evaluation here. First of all, the EPU submittal  
16 is not risk informed under Reg. Guide 1.174. The  
17 licensee didn't submit it that way, and therefore, our  
18 review is altered in some respects.

19 Of course, we're using the EPU review  
20 manual, RS001, and it tells me licensees need to  
21 perform risk evaluations to demonstrate that the risks  
22 are acceptable, but it doesn't define what acceptable  
23 risk is in this review standard, and to determine if  
24 special circumstances exist, that could potentially  
25 rebut the presumption of adequate protection provided

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1 by the alliance complying with the existing regulatory  
2 requirements.

3 Okay. We have definitions or examples of  
4 types of special circumstances in the standard review  
5 plan, Appendix D. Okay? For example, compromising  
6 defense in depth, things like that. And in fact, SPR-  
7 19, Appendix D, one of the examples of a potential  
8 special circumstance is power up rate. Okay? So  
9 that's why we do these sorts of reviews.

10 But realize we're using the PRA, the risk  
11 evaluation to drill down into the EPU to see if we  
12 could find something that could potentially be a  
13 problem. And the fact is after all of the EPUs we've  
14 looked at in PRA space, we don't tend to find very  
15 much risk, and I think it goes to the questions that  
16 Dr. Kress was saying earlier. It's almost as if PRA  
17 is incapable of finding the actual risk to the way we  
18 currently practice it.

19 We would need to extent a full Level 3 or  
20 something like this. So my feeling is it would be  
21 unusual for me as a risk analyst to find something in  
22 EPU that one of the other technical branches wasn't on  
23 top of already. In other words, we would confirm and  
24 say, well, how bad could it really be in risk based,  
25 like that.

1 Okay. Slide 4.

2 It's interesting. I was struck when VY  
3 was making their presentation. They didn't look at my  
4 slides, and I didn't look at their slides, but you'll  
5 see the same information here, like this. So they've  
6 done a full power Level 1 PRA. Realize their internal  
7 events model is a linked event tree approach. It's a  
8 support state approach implemented in the risk man  
9 software.

10 MEMBER WALLIS: So you're describing now  
11 what they did, not what you did?

12 MR. STUTZKE: Right.

13 Seismic margins method, EPRI-5 methodology  
14 for fires, the so-called hypho-related risk based on  
15 reviewing, again, standard review plan requirements.

16 They do have -- they didn't take the  
17 credit probably that they should. They have a full  
18 Level 2 PRA. It's not just a simple large early  
19 release frequency calculator.

20 MEMBER KRESS: Does that mean it has  
21 fission products in it?

22 MR. STUTZKE: Yeah. It goes all the way  
23 out to release fractions.

24 MEMBER KRESS: Okay. That's nice to know.

25 MR. STUTZKE: That's impressive. You

1 don't usually see people take the effort to maintain  
2 this type of model anymore.

3 So on Slide 5, again, as they had  
4 previously noted, they made a small increase to the  
5 turbine trip frequency. This is to account for the  
6 fact that the post EPU plant requires three out of  
7 three reactor feedwater pumps, whereas the pre-EPU  
8 plant only required two out of three.

9 Okay. So a trip of a single feedwater  
10 pump may cause a partial loss of feedwater, but that's  
11 bend in the PRA under turbine trip. When they say  
12 loss of main feedwater, they mean total loss of main  
13 feedwater.

14 I looked to see why there were no other  
15 changes to the initiating event frequencies like this.  
16 One of the things I noted was the turbine bypass  
17 capacity has decreased under EPU. They're generating  
18 more power, but they haven't added any valves like  
19 this.

20 Well, the fact is that they don't use  
21 turbine bypass to avert reactor trip above I think  
22 it's about 30 percent or so. So it has no influence  
23 on it.

24 One of the big questions is what is the  
25 impact of LOOP frequency, loss of off-site power

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1 frequency like this. As you've heard earlier, the  
2 licensee is making and has made extensive hardware  
3 modifications to maintain reactive load, rewinding the  
4 main generator, a large capacitor bank, et cetera, et  
5 cetera.

6 They already have actions to preserve grid  
7 stability in place, and some of those actions may  
8 necessitate lowering power as they need to.

9 Finally, I looked at the LOOP frequencies  
10 in their PRA study, and I compared it to the recent  
11 LOOP frequency data estimated by the Office of  
12 Research. These are frequencies research had  
13 generated in response to an NRR user need following  
14 the August 2003 northeast blackout, and in fact, the  
15 more recent research data indicates a lower LOOP  
16 frequency than the licensee was currently using. So  
17 I think they've bounded it pretty well like that.

18 On Slide 6, no impact on LOCA frequencies.  
19 One that I had probed them about concerns inadvertent  
20 open relief valves, IORB sequences, and the reason is  
21 that elsewhere in the submittal they talked about the  
22 possibility of flow induced vibrations inducing  
23 inadvertent open relief valves or causing stuck open  
24 relief valves.

25 So I had posed an RAI for them and said,

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1 you know, the gist of it was how come it's discussed  
2 in this one section and the PRA is rather silent on  
3 it.

4 And they provided these explanations to  
5 me: no change in the seating force on the pilot  
6 valves; any possible flow induced vibrations wouldn't  
7 be transmitted actually to the valves, and so forth  
8 and so on.

9 I think notably if the valves were, in  
10 fact, leaking, they would detect it, and if necessary,  
11 shut the plant down to fix it. So it wouldn't  
12 degenerate into a true inadvertent open relief valve  
13 initiating event like this.

14 I looked at all the other hardware  
15 modifications. There's nothing they're doing to  
16 support systems that would cause me to believe they  
17 would change the frequency of support system  
18 initiating events. No change in internal flood  
19 frequencies, again, because they're not changing any  
20 of the hardware; they're not changing how they inspect  
21 it or how often.

22 As I was pointing out, the internal floods  
23 are part of what they call the internal events PRA.  
24 It's not a separate study. It's enveloped in there.

25 Okay. As far as accident sequences, they

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1 did what I considered a rather extensive set of MAAP  
2 runs to assess the impact of the proposed EPU on the  
3 Level 1 PRAs, 60 MAAP runs. That's quite a lot. I  
4 was impressed by the amount of effort they put into  
5 it.

6 Of course, one can debate whether MAAP is  
7 a good code or a bad code and for various reasons that  
8 are well beyond me, but they have a tool and they used  
9 it, and I think that's noteworthy like this.

10 CHAIRMAN DENNING: And basically they used  
11 to determine success criteria?

12 MR. STUTZKE: Success criteria and timing  
13 of operator actions that drive the PRA, and I'll  
14 explain about how that's used in some detail.

15 They did add an extra spring safety valve,  
16 which changed the ATWS success criteria. Again, I  
17 asked about the reduced turbine bypass capacity. It  
18 doesn't affect the success criteria for ATWS like  
19 this.

20 The last bullet, we've already talked  
21 before about the credit for containment accident  
22 pressure to maintain a positive suction head.  
23 Realistic evaluation indicates that they don't need  
24 the credit, that MPSH would be adequate without it.

25 As you're aware, they have done some

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1 sensitivity studies. I've done some sensitivity  
2 studies trying to get around the modeling uncertainty  
3 on this. Following my return from Vermont a couple of  
4 weeks ago, we framed some additional questions,  
5 requests for additional information. We had discussed  
6 this with a licensee, and I think formally they were  
7 sent out like yesterday or today or so.

8 So I'm awaiting their response to my  
9 formal questions.

10 MEMBER WALLIS: Does this give what I was  
11 looking for earlier, which was sort of probability?  
12 They said the realistic evaluation shows it's not  
13 needed. But is there some tale of the uncertainty  
14 distribution where in one case out of 1,000 you might  
15 need NPSH?

16 MR. STUTZKE: Well, it's true, but you  
17 would be talking about uncertainties that PRA analysts  
18 don't normally deal with. You're talking about the  
19 uncertainty --

20 MEMBER WALLIS: That's good for you to  
21 deal with.

22 MR. STUTZKE: The actual uncertainty in  
23 the calculation of available net positive suction  
24 head, for example, the friction factor is unknown.  
25 The strain of loading is unknown.

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1 MEMBER WALLIS: Temperatures and  
2 everything.

3 MR. STUTZKE: Like that. When a PRA  
4 analyst does these, we use realistic assumptions. In  
5 other words, we don't deliberately add conservatism,  
6 but as raising up the decay heat or things like that.

7 And we define a definition of core damage.  
8 Normally it's peak center line temperature exceeds  
9 some value or the core is uncovered with no hope of  
10 refiling it, some success criteria like this such that  
11 one may make a thermal hydraulic calculation. We can  
12 determine yes or no, was that definition of core  
13 damage reached or not. So it's very black and white  
14 for us. We don't really look at the uncertainty in  
15 the PRA calculation.

16 MEMBER KRESS: There's two parts to this  
17 uncertainty. There's the uncertainty in the actual  
18 net positive suction head you're going to get as a  
19 result of the debris build-up and the pressure drop  
20 and stuff, and then there's the uncertainty in the  
21 actual pressure in the containment.

22 Now, the PRA could be used to get that  
23 second part.

24 MR. STUTZKE: That's right.

25 MEMBER KRESS: And it looks to me like it

1 would be a relatively easy uncertainty analysis if you  
2 had the data to do the other part and then overlap the  
3 two uncertainties.

4 MR. STUTZKE: Well, I don't know that I  
5 would say it's easy. I'm unaware that anybody has  
6 tried to calculate the uncertainty in the pressure  
7 response.

8 MEMBER KRESS: Well, you've got the  
9 models.

10 MR. STUTZKE: It's true, and you would  
11 have to run the models. You'd have to make many MAAP  
12 runs in Monte Carlo fashion.

13 MEMBER KRESS: You'd have to hook it up to  
14 a Monte Carlo.

15 CHAIRMAN DENNING: But PRA has not treated  
16 phenomenological uncertainties in that way, and again,  
17 there are kind of two kinds of uncertainties here.  
18 There's a variability, but I don't think that's what  
19 really is the element here. I think it really is  
20 phenomenological uncertainty in the ability of our  
21 models to predict those phenomena, and we just don't  
22 address it.

23 If we did address them, it would probably  
24 appear in the uncertainty in the risk number rather  
25 than in the -- if you looked at a CCDF, it would be in

1 the uncertainty in the CCDF, not in the shape of the  
2 CCDF, although the two -- it can reflect back into the  
3 mean probability, the mean risk that we deal with  
4 typically, but it's complex, and there is some work  
5 being done along these lines on treatment of  
6 phenomenological uncertainties, but there's no PRA  
7 that has really treated that in the past, that kind of  
8 treatment.

9 MEMBER KRESS: The only place I want to  
10 use the PRA is to find the uncertainty in the pressure  
11 that you're going to get in containment, and I think  
12 you could deal with that very nicely. It's a blow-  
13 down, LOCAs, and you may have to put in some  
14 probabilities of leakage and stuff like that, but  
15 that's what I want to use the PRA for.

16 And then you say, now, we've got this  
17 other aspect of the flow through the ECCS system and  
18 the spray system and the debris build-up and whether  
19 or not the uncertainties in the LOCA generating debris  
20 and getting there. That's another -- I don't think  
21 you can use the PRA for that, but you've got models  
22 for it, and I think you could --

23 CHAIRMAN DENNING: How did you say you  
24 were going to use the PRA to give you a pressure? You  
25 use the code to give you pressure.

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1 MEMBER KRESS: Well, you use something  
2 like the blow-down models that are in the codes.

3 MEMBER SIEBER: I would actually prefer  
4 not to see PRA used in this, but I think that the  
5 fourth bullet here is extremely important with regard  
6 to preserving things like defense in depth and  
7 independence of barriers and so forth, and if a  
8 realistic deterministic evaluation would show that  
9 containment accident pressure credit is not needed for  
10 MPSH and that an appropriate phenomenological and  
11 sensitivity studies were done, again, in a  
12 deterministic way, then you could preserve the  
13 concepts of defense in depth and so forth and use that  
14 as the basis for allowing a power upgrade to the  
15 extent that it would be allowed under the conditions  
16 that are there.

17 I'd prefer that approach.

18 CHAIRMAN DENNING: Yes, and I'd like to  
19 ask Entergy if there's anybody that could speak to  
20 that. Have you considered that approach of the  
21 realistic analysis with some consideration of  
22 uncertainties on this NPSH problem?

23 Because it certainly is one that gives us  
24 a lot of difficulty, and I think that the direction  
25 that Jack is going is one that is very appealing, and

1 I'm just wondering whether you've given thought to  
2 that.

3 MR. NICHOLS: Well, we've given thought to  
4 it. This is Craig Nichols from Entergy.

5 Since it's not allowed to do a realistic  
6 LOCA, et cetera, by rules, we cannot do that. We have  
7 done that in sensitivity space and provided that  
8 information to the staff for their use, and I believe  
9 as we showed in our earlier presentation, such  
10 treatment that way in realistic space in almost every  
11 domain shows that, as stated here, COP would not be  
12 needed.

13 MEMBER WALLIS: You showed us a little  
14 table, and it just said taking this temperature, this  
15 temperature, and so on, and then the full temperature  
16 was 169 rather than one -- but that was only a few  
17 cases, and what would really help me, and it's along  
18 the lines Jack is saying, is if you could go through  
19 putting all of the uncertainties, and then you would  
20 say realistic evaluation with the consideration  
21 uncertainties shows that the probability that the  
22 containment accident credit will be needed is one in  
23 ten to the minus six or something. Then we can make  
24 an independent judgment about, well, okay, we don't  
25 need it with PRAs and everything.

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1 MR. NICHOLS: I think now I understand  
2 what you're asking for.

3 MEMBER WALLIS: It looked as if that would  
4 be the case.

5 MR. NICHOLS: A uncertainty treatment --

6 MEMBER WALLIS: But you didn't go that  
7 far. I mean you were still conservative in some other  
8 respect.

9 CHAIRMAN DENNING: Well, recognize, again,  
10 we're not asking you for anything here. We're just  
11 exploring what you've done. You know, there's no  
12 direction or request from us.

13 MR. NICHOLS: We do understand the request  
14 or the --

15 CHAIRMAN DENNING: But we're just curious  
16 whether you've done it --

17 MR. NICHOLS: -- the curiosity.

18 CHAIRMAN DENNING: -- and whether you had  
19 any data that would have helped us along those lines.

20 MR. NICHOLS: We have done some work in  
21 that area. I don't believe that we're ready to  
22 present it now.

23 MEMBER WALLIS: Well, I think the staff  
24 did something, too. The staff looked at uncertainties  
25 and then this NPSH problem, too, and sort of said,

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1 well, there were so many conservatisms that it won't  
2 be needed, but it was not done in a very complete and  
3 quantitative way.

4 CHAIRMAN DENNING: Well, let's pretty  
5 Marty a little bit because he came up with success  
6 criteria that he used in his analysis, and I'm  
7 curious. Could you talk to us about those success  
8 criteria that you used there?

9 MR. STUTZKE: Well, let me speak generally  
10 how PRA analysts divines success criteria. When a PRA  
11 analyst talks about success criteria, normally it's a  
12 very clear-cut situation. For example, one has a  
13 three-train system and I want to know do I need one  
14 out of three pumps working or two out of three pumps  
15 working.

16 Okay. That is a big difference. Okay?  
17 It's unlikely that I would miss something or it would  
18 have enough phenomenological uncertainty in the  
19 thermal hydraulic calculation that I could ever change  
20 my opinion between one out of three versus two out of  
21 three pumps.

22 I would remind you that a lot of the IPES  
23 and certainly when I first got into the business, we  
24 never ran codes like MAAP to determine success  
25 criteria. It was a back-of-the-envelope calculation.

1 Okay?

2 That was adequate because we couldn't have  
3 been that far off. That was the judgment like this.

4 When you deal with the issue of credit for  
5 containment accident pressure, you know, now you're  
6 pushing some of the cherished beliefs of PRA analysts  
7 that we can't divine success criteria like we do and  
8 we need to do a lot more work.

9 You know, my feeling, let's -- the other  
10 thing I would say is let's don't get confused between  
11 a PRA versus a probabilistic propagation of  
12 uncertainty. Right? That's something that anybody  
13 can do. It's just a function of random variables, and  
14 I apply the appropriate distributions and I calculate  
15 it.

16 MEMBER WALLIS: But it really does apply  
17 in a PRA. When you've got to make a decision is it  
18 successful or not, this thermal hydraulic uncertainty  
19 really does come into that decision if you did the  
20 whole Joe.

21 CHAIRMAN DENNING: We don't do the whole  
22 Joe.

23 MEMBER WALLIS: But you don't do it. You  
24 don't do it. You can't.

25 MR. STUTZKE: No.

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1 MEMBER SIEBER: It's the definition of  
2 what does working mean. You know, sometimes it works,  
3 sometimes it doesn't.

4 MEMBER KRESS: The reason I suggested the  
5 PRA for one part of it is because you've got the  
6 frequencies and the LOCAs built into it, and it's not  
7 the probability long term. Well, it's probably --  
8 it's an initiating event times the probability.

9 MR. STUTZKE: So to answer Dr. Denning's  
10 question, how did I come up with the success criteria?  
11 I assumed them. I said if this is true and this is  
12 true and this true, I can develop a model, and this is  
13 the delta CDF.

14 CHAIRMAN DENNING: And the criteria you  
15 used, if I remember it, was that RHR availability  
16 within four hours or something like that. Is that --

17 MR. STUTZKE: Suppression pool cooling.  
18 The assumptions were whenever I needed to have some  
19 sort of accident sequence that dumped heat into the  
20 Taurus (phonetic), okay, and I needed to be able to  
21 run either low pressure or core spray pumps, and there  
22 was a hole in the containment so that I had no over  
23 pressure, and the suppression pool cooling wasn't  
24 started in four hours. That seems to be a difference  
25 between my analysis and what the licensee had done

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1 because I understand the suppression pool needs some  
2 time to get heated up before we actually create the  
3 problem within PSH, whereas in their analysis it just  
4 goes off the core damage basically. It's one of the  
5 reasons why they got such a large delta CDF as  
6 compared to I did because they made different  
7 assumptions in the sensitivity analysis.

8 The idea is --

9 MEMBER WALLIS: Ten times as much as you  
10 did, didn't they?

11 MR. STUTZKE: Yeah, ten times as much. It  
12 has caused me considerable lost sleep over the last  
13 couple of weeks trying to understand why did they get  
14 such a big number like this.

15 CHAIRMAN DENNING: Well, we heard a lot of  
16 it right here as to why the numbers are bit.

17 MR. STUTZKE: Yeah, but again, it's an  
18 idea that let's make some assumptions and do a PRA  
19 calculation, and the idea is that if the delta CDF,  
20 you know, the change in risk is small enough, you gain  
21 some level of comfort with that result. That's the  
22 idea.

23 Okay. I presume I will be back to speak  
24 to the full committee on containment accident pressure  
25 later on. So let's --

1 MEMBER SIEBER: That would be a good  
2 assumption.

3 MEMBER WALLIS: So you're going to lose  
4 some more sleep before then.

5 (Laughter.)

6 MR. STUTZKE: Either that or I need to  
7 find a new job.

8 MEMBER SIEBER: No, just lose some sleep.

9 MR. STUTZKE: Yeah, but I'll table it now  
10 because the licensee hasn't formally responded to my  
11 RAIs, and I'm in the process of revising safety  
12 evaluation now.

13 Okay. So on Slide No. 8 --

14 MEMBER WALLIS: Wait a minute. Let's go  
15 back. They're in the process of responding to your  
16 RAIs and all of this is going to be finished by next  
17 week or not?

18 MR. ENNIS: This is Rick Ennis.

19 As I had mentioned yesterday, the intent  
20 is to be able to discuss this as full committee at  
21 least verbally. We don't think we have time to fully  
22 revise the SE and issue it again.

23 MEMBER WALLIS: But these RAIs are going  
24 to be responded to by next week?

25 MR. ENNIS: We had requested that they be

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1 responded to by Friday, this Friday. And we have  
2 drafts on a computer here now, responses to those.

3 MEMBER WALLIS: I don't think it would be  
4 good to come to the full committee with too many of  
5 these loose ends, the RAIs not responded to and things  
6 like that.

7 MR. HOLDEN: Yeah, this is Corney Holden.

8 I think the other point that we made at  
9 the start, the SE right now, we've drawn a conclusion  
10 on the SE in that we've asked for additional  
11 information and risk and will include that, and that  
12 will supplement what we already have.

13 CHAIRMAN DENNING: What they said was  
14 based upon the PRA work that the staff had done,  
15 they've concluded the acceptability in that.

16 MR. STUTZKE: That's correct.

17 CHAIRMAN DENNING: And that this was not  
18 then dependent upon resolution of those RAIs.

19 MR. STUTZKE: Right. I haven't decided  
20 yet, nor have I discussed with my management, but you  
21 know, the PRA evaluations that I did, the scoping  
22 analysis may disappear from the safety evaluation  
23 altogether. We may rely on the licensee's work,  
24 review it, and consider that it's acceptable.

25 MEMBER WALLIS: That's surprising. I

1 mean, the fact that you did this confirmatory analysis  
2 I think helps us. It would be a pity if it all  
3 disappeared.

4 MR. STUTZKE: That's why I need to  
5 discuss.

6 CHAIRMAN DENNING: Okay. Continue.

7 MR. STUTZKE: Okay. On Slide No. 8,  
8 there's no changes to the failure rate data that the  
9 licensee is using in their PRA. It seems reasonable  
10 because as long as operating ranges, limitations on  
11 equipments are being observed.

12 There was a change in the probability of  
13 stuck open relief valve, SORV. I apologize. This is  
14 not worded very clearly. In fact, right now it's  
15 nonsense.

16 The idea is this. As you increase decay  
17 heat and you have a reactor trip of some sort, the  
18 valve chatters more. It opens-closes, opens-closes,  
19 opens-closes, right? And it will do that more often,  
20 extended power uprate conditions than not, and so  
21 every time you challenge the valve to open, you fail  
22 to reseal it and create an accident sequence.

23 The licensee had looked at several ways of  
24 doing this. One was just adding up 20 percent to the  
25 failure probability of the valve, being 20 percent

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1 decay heat. At the lower end, they will say, "Well,  
2 the valve reliability, if it sticks open, it will  
3 stick open on the first demand. So there's no  
4 change."

5 They actually looked at a number of MAAP  
6 runs for transients and counted the number of relief  
7 valve cycles and came up with this 15 percent. So I  
8 think they've got it reasonably bounded here.

9 I'll point out stuck open relief valve  
10 sequences don't contribute notably to their risk at  
11 all.

12 CHAIRMAN DENNING: What does a realistic  
13 model look like for a stuck open relief valve as far  
14 as the data is concerned? Do they stick open on the  
15 first one or do they stick open on the tenth one or is  
16 it --

17 MR. STUTZKE: Well, that's the problem.  
18 Some people believe if it fails it will fail the first  
19 time, but once it gets exercised, it can recede.  
20 Other people believe it's a matter of wear. So it  
21 wants to stick open on the last cycle.

22 I've seen people try to apply binomial  
23 distribution to it and say it has got a constant  
24 probability of demand, and so I count that up, and you  
25 get a range of answers in there.

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1 MEMBER WALLIS: And if it leaks, it leaks  
2 whether a PWR, and you probably build up boron, but  
3 you don't in this case.

4 MR. STUTZKE: No, you won't.

5 I mean, when I say "stuck open," I mean  
6 stuck open enough to create small LOCA or medium LOCA.

7 MEMBER WALLIS: Well, I know. I was  
8 thinking of TMI again. The stuck open probably was  
9 related to the history of that leaking valve over a  
10 period of time.

11 MR. STUTZKE: Yes.

12 CHAIRMAN DENNING: You're saying the  
13 sticking open was? I'm not sure that's true.

14 MEMBER WALLIS: I think it was. It had  
15 been leaking more and more over a period of time, and  
16 I think that -- well, it's a red herring.

17 CHAIRMAN DENNING: It's a different  
18 argument.

19 MR. STUTZKE: Human reliability. I was  
20 intrigued this morning and this afternoon when you  
21 gentlemen were discussing human reliability with other  
22 people and was very glad that Dr. Apostolakis is not  
23 sitting here to interrogate me this afternoon.

24 But I wanted to try to --

25 MEMBER KRESS: He'll get his chance next

1 week.

2 (Laughter.)

3 MEMBER SIEBER: He will be next week.

4 MR. STUTZKE: It's inevitable, right?

5 I wanted to give you a little explanation  
6 of how timing of operator actions is used to determine  
7 their probability of occurrence like this and,  
8 therefore, to give you some idea of changes of timing  
9 driven by the extended power uprate and what that  
10 really means in here and to try to remind you of some  
11 features.

12 I, like most PRA analysts, develop a time  
13 sequence of an event. So we'll say at time zero the  
14 event occurs. At time one there's some compelling  
15 signal that the event has actually occurred,  
16 enunciated responses, things like this. The  
17 compelling signal, that is what tells the operator go  
18 do something. So now he's reached some point in his  
19 procedural space telling him to do things.

20 At some later time, we'll call it T2, it's  
21 what I'll call the point of return. If they take  
22 action after that time it's of no avail. T3 then  
23 would be some time when a bad consequence occurs as a  
24 result of the failure like this.

25 So the total time frame from T0 to T3,

1 that's what you get out of a thermal hydraulic  
2 calculation, a MAAP run. The examples that were being  
3 discussed this morning, that's the 6.2 minutes  
4 available time to inhibit ADS being reduced down to  
5 5.4 minutes. So that's an actual thermal hydraulic  
6 calculation like this, although I will point out in  
7 the early days of PRA we used to do those by paper and  
8 pencil, 60 minutes to half an hour, things like this.

9 The time from we'll call it the point of  
10 return to the bad consequence, that's the  
11 implementation time. That's the time it takes the  
12 operator to physically get out of his chair, go up to  
13 the board, figure out which control to operate, push  
14 the button, and do what he needs to do.

15 Okay. For in control room actions, that  
16 time does -- implementation times tend to be very  
17 short, right, unless the control room is physically  
18 big. I've not been in the Vermont Yankee control  
19 room. I've been into several, for example, at N  
20 Reactor where the control room is about 30 meters  
21 long, and it's a hike to get from one end to the  
22 other, and the implementation time is important like  
23 this.

24 So the time between the compelling signal  
25 and this point of no return is called diagnosis and

1 decision making time. I call it thinking time, the  
2 fancy name "cognitive time."

3 So now the operator perceives something is  
4 amiss. Okay? He needs to overcome his shock. He  
5 needs to figure out what's going on like this. He  
6 needs to recall his training and decide out of all the  
7 things he knows, what's the appropriate thing to do?

8 In the case of this inhibit ADS, it would  
9 appear that he's got about four minutes to sit and  
10 think about what he needs to do until the time he  
11 actually needs to do it.

12 Well, that four-minute time is called the  
13 available time, and that is one of the inputs into the  
14 calculation of the cognitive error probability. I say  
15 one of the inputs because the human error probability  
16 not only depends on time, but other sorts of factors,  
17 the man-machine interface, psychological stress, work  
18 load, training procedures, things like this.

19 All of these factors are put into an HRA  
20 quantitative model to generate the final number. One  
21 of the questions that was raised this morning is what  
22 about simultaneous actions. During an ATWS there's a  
23 lot going on in a very short time, the need to inhibit  
24 ADS, the need to inject slicks, the need to lower  
25 water level down to tap, to reduce the power.

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1 HRA people tend to think of those as  
2 operator burdens, and they are treated by certain  
3 performance shaping factors, notably the workload  
4 performance shaping factor. So if he has multiple  
5 concurrent actions going on, we as a higher  
6 performance shaping factor -- it's basically a  
7 multiplier onto a basic probability. So it just  
8 scales it up like that. Okay?

9 In addition, each one of these human  
10 actions may be modeled separately. It appears they're  
11 on separate basic events in the model, and HRA  
12 analysts are very careful to worry about the  
13 dependency among those actions, the idea being, for  
14 example, if he fails to inhibit ADS, maybe he doesn't  
15 understand what's going on, and so he will fail to  
16 lower the water level and fail to inject slicks. He's  
17 got a total brain loss. He's confused. Okay?

18 And HRA people try to handle that with a  
19 dependency analysis.

20 As far as Vermont Yankee goes, they did a  
21 large amount of work on the human reliability,  
22 probably more than I've seen for a while. For  
23 example, they looked at the man-machine interface to  
24 decide whether those performance shaping factors would  
25 be affected, and the answer was no like that.

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1                   So, in other words, they're considering  
2 the change in display, the span of instruments and  
3 things like this, the training in order to handle the  
4 new plant.

5                   They went down and they looked at their  
6 post initiator human actions, their 59 in their model,  
7 and they recalculated 41 of the probabilities like  
8 this. They had employed a screening method that was  
9 based on primarily importance measures. They looked  
10 at combinations of Fussell-Vesely importance measures  
11 and risk achievement worth.

12                   Then they also had another one that said  
13 any human action that had less than 30 minutes  
14 available time we will reassess like this.

15                   MEMBER KRESS: How did they know what  
16 value of, say, Fussell-Vesely or RAW to cut off and  
17 say, "We'll not deal with those below that"?

18                   MR. STUTZKE: It appears to me they picked  
19 the magic numbers out of 50.69, the Fussell-Vesely of  
20 .005 and the risk achievement worth of two. So I  
21 asked them in RAI. I said give me all of the human  
22 errors, even the ones you screened out, and I want to  
23 look at them and see whether I agree that they should  
24 be screened out or not.

25                   And so I looked at all 59 of them and

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1 agreed with their assessment because the ones they  
2 threw out aren't affected by the timing tremendously.

3 Realize whenever you start the screening  
4 process on importance measures, basically you're  
5 trying to save yourself some analysis time. Let me  
6 calculate 41 instead of 59.

7 MEMBER KRESS: Not much difference there,  
8 is there?

9 MR. STUTZKE: Well, my feeling now is with  
10 tools like EPRI's human reliability calculator, it's  
11 just as easy to do 59 rather than to defend why I  
12 picked these 41s, you know. You can save yourself an  
13 RAI, things like that.

14 So anyway, I go and looked at what they  
15 threw away and convinced myself that it looked pretty  
16 good, and then they recalculated these probabilities  
17 to handle the shorter available response times, and  
18 that's all put into the model.

19 As I had said before, they looked at the  
20 dependencies. They reassessed the dependencies in the  
21 model. It appears to be almost an analysis, complete  
22 new analysis from scratch rather than just presuming  
23 what they had done before was okay. So I feel that  
24 they've done a pretty good job with looking at the  
25 human reliability.

1           The thing that I would point out in all of  
2 this, when we go back to the time lines, we have an  
3 uncertainty of how much available time there really  
4 is, phenomenologically and things like this. There's  
5 an uncertainty in how much time it takes the guy to  
6 respond, implementation time.

7           So by necessity then you've induced an  
8 uncertainty then in the available time. Okay? So I  
9 don't know whether I have got four minutes available  
10 to think or three and a half minutes or whatever it  
11 is.

12           On top of that, now I put that number into  
13 something called a time response correlation or time  
14 reliability correlation, depending on who you want to  
15 call, but the idea is that on the X axis it says  
16 here's the available time, and on the Y axis it says  
17 here's the magic probability of failure, right?

18           These curves are a dime a dozen. Right?  
19 If I put five HRA analysts in the room, I would have  
20 eight curves. Okay? There's not a large consensus on  
21 it. It's one of the sore points with Professor  
22 Apostolakis. It's like why do you use this NUREG and  
23 why don't you use ATHENA.

24           Well, that's just another NUREG, and you  
25 know, which one is the right one to use? And the fact

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1 is there's not good consensus among the community as  
2 to what the appropriate thing is, the point being that  
3 when you see a small change in time, say --

4 MEMBER WALLIS: But can I ask you this one  
5 that I was referring to, the GE-3309TP? Is that a  
6 good one?

7 (Laughter.)

8 MR. STUTZKE: I'd have to look to see what  
9 they actually did, which number they had, but no  
10 matter which, you know, I feel like you're damned if  
11 you do and damned if you don't. No matter which book  
12 I pull out of my bookcase, somebody will say I should  
13 have used that one. Okay?

14 MEMBER KRESS: George will say that now.

15 MR. STUTZKE: You will see in VY  
16 unfortunately I didn't have a chance to present it,  
17 but I have done a sensitivity to the human reliability  
18 method, and I pulled them out from over about a 20-  
19 year span, and you'll see the number doesn't change  
20 that much.

21 Well, one of the reasons is that the time  
22 response correlation is derived out of simulator data  
23 that industry did, EPRI did a long time ago, right?  
24 That the only way to get this curve is empirically,  
25 and then one can argue whether it fits to a Weibold

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1 distribution or a log normal, which is one of the big  
2 screaming arguments that you hear in this.

3 But the fact is you're dealing with a  
4 pretty sparse set of data, and you're trying to  
5 extrapolate it or interpolate it to situations where  
6 maybe it doesn't apply like this.

7 Now, the result of this is tremendous  
8 uncertainty in the results of the PRA like that.

9 Okay. Next slide.

10 Okay. This shows you the impact of the  
11 extended power uprate on core damage frequency by  
12 comparing it to the Reg. Guide 1.174 risk acceptance  
13 guidelines. You notice the guidelines are actually  
14 the stair step function. The bottom step, the bottom  
15 tread there is the region of very small change in  
16 risk, and that's where the black dot is, and that's  
17 where they come out.

18 For the middle step we have small changes  
19 in risk. Well, if it's in Region 2, it may still be  
20 acceptable. Okay? When you get into the Region 1,  
21 that's when we really begin to worry. Okay?

22 With respect to this review of the  
23 extended power uprate, if their risk metrics had  
24 landed in Region 1, I would begin to question adequate  
25 protection. That's kind of my personal trigger,

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1 although there are no hard and fast rules on this, but  
2 you can see clearly from the risks that they've  
3 actually calculated here that they're in the very  
4 small regime.

5 MEMBER KRESS: Now, that's the risk of  
6 internal events?

7 MR. STUTZKE: Yes, sir, that's what I  
8 wanted to point to. In fact, that dot moves up  
9 diagonally to the right because there's risk from  
10 external events in the base model, and there's a delta  
11 risk due to external events that they're not  
12 quantifying. There's also risk due to shutdown and  
13 low power event, okay, like that.

14 MEMBER KRESS: So you sort of have to  
15 guess how far it goes.

16 MR. STUTZKE: That's right.

17 The other thing I'll point out is these  
18 are not hard and fast boundaries between the region.  
19 They're fuzzy. Okay?

20 CHAIRMAN DENNING: You know, in this case,  
21 I think the external events, you know, they're  
22 unlikely to be significantly changed here.

23 MR. STUTZKE: That's correct.

24 CHAIRMAN DENNING: And the low power for  
25 the arguments they made. So it's not as obviously a

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1 deficiency as we see in some cases of application of  
2 1174 where there really are things that could  
3 significantly affect like fire risks and stuff like  
4 that. I don't see that here.

5 MR. STUTZKE: yeah, that's correct, and  
6 we'll talk about what's missing in a few other slides  
7 here.

8 Okay. As far as to the impact on the  
9 Level 2 PRA, again, the licensee had done a number of  
10 MAAP runs to support their EPU. No changes in the  
11 Level 2 success criteria. The actual modeling of  
12 accident progression, the BIN categorizations like  
13 this, basically the results of the delta LERF number  
14 they calculate is being driven by the delta CDF from  
15 the internal event, from their model like this.

16 They did look at some small changes in  
17 timing to see whether it made any difference or not,  
18 and it doesn't appear to be very strong. So when you  
19 plot this up against the risk acceptance guidelines,  
20 you have what I'll guess personally -- I'll say what  
21 a regulator hates to see. Now we're on the cusp here.  
22 Okay? I've got some sort of guideline, and I am smack  
23 dab right on top of that guideline, but I know my  
24 guideline is fuzzy and I know that this dot is fuzzy,  
25 too.

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1 My point is I'm still acceptable. Okay?  
2 Region 2 is still acceptable under certain conditions  
3 like this, but now you can see I'm getting closer to  
4 the boundary. So what's the impact on LERF from  
5 external events?

6 And now I may be actually pushing it a  
7 little bit. So we need to consider the external  
8 events in some detail. They hand run the EPRI 5  
9 methodology, the fire induced vulnerability  
10 evaluation, basically went back and looked at it again  
11 to see if changes needed to be made to it.

12 As you know, what you're doing in the EPU,  
13 it doesn't change the drivers to the methodology. For  
14 example, you're not physically changing the fire  
15 protection system. You're not adding combustible  
16 loading, things like this. So the frequency of fires  
17 shouldn't change. The plant responds won't change  
18 noticeably.

19 Now, five is a semi-quantitative result,  
20 but the CDF it calculates is not as good a fidelity as  
21 the CDF from the internal events. It's kind of gauge  
22 to tell you, gee, which room really is the problem  
23 point like this. It's a ranking methodology almost in  
24 my mind.

25 So they didn't determine any

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1 vulnerabilities when they relooked at their five  
2 study, and I think that's a reasonable conclusion.

3 For the seismic PRA study, nonselect 14,  
4 they've used the EPRI seismic margins method. That  
5 was part of their IPEEE response, and I dug into this  
6 a little bit following our meeting in Vermont,  
7 motivated by questions that Bill Sherman had asked  
8 like this.

9 When the IPEEE submittal guidance came  
10 out, NUREG 1409, Vermont Yankee was identified as a  
11 focus scope 0.3G plant. What does that mean?

12 Okay. We have to realize that NUREG 1407  
13 assigned every power plant in the country to one of  
14 four categories. You either had a 0.5G review level  
15 earthquake. Those were the plants in California. You  
16 had a reduced scope set of plants. Those were like  
17 Crystal River or Turkey Point down in Florida where  
18 they don't have a large seismic hazard, and everything  
19 else was poured into the 0.3G category, everything.

20 Okay. That 0.3G category is called a  
21 review level earthquake, okay, and it is loosely  
22 related to the seismic hazards at the site, but if you  
23 read 1407, Appendix A, it explains why it's not  
24 directly tied into risk. It's not like I'm saying,  
25 gee, the frequency of an earthquake of 0.3G is below

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1 ten to the minus six. That's a false interpretation  
2 of this number.

3 Okay. By comparison, the operating basis  
4 earthquake at VY is 0.07Gs. A shutdown earthquake is  
5 two times that or .14G.

6 The focused scope means that they're  
7 limited when relay chatter was evaluated to review  
8 relays that weren't in the USIA 46 program like that.  
9 Relays are important here because that's the  
10 containment isolation signal that may impact over  
11 pressure potentially.

12 But when you look at the seismic risk,  
13 things that drive seismic risk like changes to  
14 structures so that you have turbine building colliding  
15 with the reactor building things, nothing is  
16 happening. They're not modifying the structures; they  
17 didn't modify the equipment mounting.

18 Specifically I looked up the HCLPF values,  
19 high confidence of low probability of failure, for  
20 reactor coolant system in containment, and they're  
21 greater than the 0.3G screening criteria. It means  
22 these are very rugged systems. It's not likely that  
23 an earthquake would simultaneously create a LOCA and  
24 fail the containment.

25 So as a result there's no new

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1 vulnerabilities that have been identified arising from  
2 the EPU concerning seismic risk.

3 On Slide 16, the shutdown risk evaluation,  
4 again, it's a qualitative assessment, and the licensee  
5 pretty well discussed it earlier today. We don't  
6 create any new initiating events. No reason to  
7 suspect that the frequency of already identified  
8 shutdown initiating events would increase.

9 There are some small changes to the core  
10 boil down times for the post CPU because the decay  
11 heat is a little bit higher.

12 Should shutdown cooling fail, the plant  
13 has redundancy and diverse systems, low capacity decay  
14 heat removal systems, but because the capacity is  
15 smaller, they may be precluded if you were to lose  
16 them shortly after shutdown, but again, this seems to  
17 be a minor effect like this.

18 And, again, some small reductions in  
19 available operator action times. Again, as I pointed  
20 out, if you have four hours to respond and the delta  
21 is ten minutes, it's almost no change at all like  
22 this.

23 Again, you control outage risk and attract  
24 configurational risk in general. They have  
25 computerized risk monitor that they will maintain like

1 this.

2 Okay. Slide 17 is the discussion of the  
3 PRA quality here. Basically the quality is okay  
4 because the PRA has been based on their IPE and IPEEE  
5 submittals, which the staff has already accepted some  
6 years ago.

7 They did have a peer review owners group  
8 back in November of 2000. All of the Category A and  
9 B findings have been resolved. I actually looked at  
10 those findings to see what the problem was and what  
11 action they had taken to resolve them, and pretty well  
12 agree with them.

13 I'll point out I've been involved in two  
14 of the pilot programs for Reg. Guide 1.200, which was  
15 our PRA quality reg. guide that endorses the ASME PRA  
16 standard, and the nature of the facts and observations  
17 that I read for Vermont Yankee were very similar to  
18 what I observed in those pilot programs. Okay?

19 So their PRA quality is as good or as bad  
20 as most everybody else's is in the industry, in my  
21 opinion, like this.

22 In addition, the staff, as you know,  
23 maintains SPAR models that drive the significance  
24 determination process, notebooks. The staff had  
25 actually gone up and benchmarked the PRA against the

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1 SPAR model in May of 2003.

2 I'd asked RAI specifically on this because  
3 it appeared the core damage frequency changed by, I  
4 guess, a factor of two over a couple of months, and I  
5 was kind of perplexed about why that happened, and  
6 they were modifying their PRA in result to this  
7 benchmarking model.

8 Okay. So I think we have good agreement,  
9 that they've been responsive. My opinion is their PRA  
10 is of adequate quality to drive the sorts of risk  
11 evaluations they need to document the CPU like this.

12 Yes, there are things that could be  
13 improved. I was encouraged to hear them thinking  
14 about fire PRAs and getting away from the EPRI FIVE.  
15 I would encourage them. I think that's the right way  
16 to go.

17 CHAIRMAN DENNING: Can I add my agreement  
18 with that, not that it will influence them? But I  
19 certainly would like to see them influenced that  
20 direction.

21 MR. STUTZKE: We need all the support we  
22 can get here like this. I think personally methods  
23 like FIVE and seismic margins, they were good at the  
24 time, but we can do better now, and there's no excuse  
25 not to do any better now. We have the computer tools,

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1 so let's use them. But a personal opinion of mine,  
2 although I'm certain most of the people that I work  
3 with would agree wholeheartedly.

4 Okay. So the conclusions are, again, my  
5 second slide that I had showed you earlier. I think  
6 they've done a good job of modeling and addressing the  
7 risk impacts within the limits of the PRA. They're  
8 clearly in compliance with Reg. Guide 1.174 acceptance  
9 guidelines. There's nothing I've been able to  
10 identify as a special circumstance so far that would  
11 question a presumption of adequate protection at this  
12 time.

13 Further questions?

14 CHAIRMAN DENNING: Any questions?

15 MEMBER KRESS: Good job.

16 CHAIRMAN DENNING: Yes, I agree. Good  
17 job. Thank you very much.

18 MR. STUTZKE: Thanks.

19 CHAIRMAN DENNING: Thank you.

20 Okay. Mr. Shadis, are you ready to talk  
21 to us?

22 PARTICIPANT: Do you want to make a  
23 presentation to us? Is there anyone else who wants to  
24 make a presentation?

25 Any other public comments?

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1 CHAIRMAN DENNING: Please make sure you  
2 speak into the mic and identify yourself.

3 MR. HOPENFELD: My name is Joe Hopenfeld.  
4 I'm a consultant to New England Coalition.

5 I'll be very, very brief because I spoke  
6 for half an hour a couple of weeks ago. Let me repeat  
7 my concern.

8 First, very simple. What happens to a  
9 damaged dryer that is exposed to DBA loads? I'd like  
10 to remind you, and I think it was mentioned here by  
11 Entergy, that these plants were designed to withstand  
12 DBA. So it's true the computer codes that were used  
13 40 years ago are a little bit different than the  
14 computer model that we're using today.

15 And based on my experience with PWRs,  
16 you'll find new things, new loads under DBA condition  
17 that you didn't see before. Obviously they have not  
18 at that time considered it a dryer that contains  
19 certain distribution of cracks of unknown size and  
20 unknown location.

21 That issue should be addressed, and I  
22 haven't heard it discussed, only very briefly.

23 The second issue, and I can go through  
24 this very, very quickly, has to do with the iodine  
25 spike or iodine releases. We heard this presentation

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1 in the afternoon, and I haven't heard anything said  
2 about the iodine uncertainty.

3 There is a generic issue that is  
4 unresolved. When you operate with EPU, under EPU  
5 conditions, the flow rates are higher. So the  
6 concentration of iodine is lower, and if you remember  
7 or you can go back to the database and you'll see when  
8 the concentration is lower, there's a potential for a  
9 much higher iodine spike, and I'm not talking factor  
10 of two or three. I'm talking an order of magnitude.

11 So are we asking ourselves are we meeting  
12 the 10 CFR 100 or the 10, what is it, 50.69? That  
13 issue hasn't been even touched on, and I think we have  
14 to assure ourselves that under the EPU conditions you  
15 meet the requirement, the legal requirements.

16 And what I would like to remind you, that  
17 the database on which the iodine spike is based on,  
18 it's purely empirical, and it is not -- you cannot  
19 extrapolate the directive to the way I understand it  
20 was done. It wasn't described in the presentation  
21 today, but from reading the SER, I believe that  
22 they're just plain extrapolated directly, and I think  
23 that issue should be addressed because you cannot  
24 assure yourselves that we meet the criteria.

25 Now, I don't know how far are we for the

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1 5 REM or whatever it is in the control room. The  
2 numbers were not presented. They were not in the SER.  
3 So I don't know how far we are, but I've looked at  
4 some numbers in other plants, and there was no order  
5 of magnitude cushion in there. They were very, very  
6 much closed.

7 So you really have to look at it. It's  
8 not an academic issue if you really want to meet the  
9 legal requirements. It's not a safety issue, but it's  
10 an issue that should be addressed.

11 The last one has to do with the delta P  
12 across the screen, and one thing that bothered me a  
13 little bit, we have some experiments at Los Alamos.  
14 We have some experiments at VY. We have some  
15 experiments at EPRI, and for a person that, you know,  
16 is kind of removed from that, it's very difficult to  
17 see how all of that matches together.

18 In addition to this, I keep hearing the  
19 word "conservatism." However, the conservatism that  
20 you're talking about is based on data which was  
21 obtained in '96 by weighing the sludge in the pool.  
22 But now what happens to all the sludge that you have  
23 during blow-down? What happened to all of the crud  
24 and the rust that you get in the drywall that's coming  
25 down there?

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1 But more important than that, the SER  
2 states that the conductivity of the coolant is  
3 different, and obviously the particle size, particle  
4 distribution is going to be affected by the pH.

5 So it's not really a conservative kind of  
6 approach. That's ridiculous, but conservative  
7 approach would be to take a one-eighth of an inch  
8 fiberglass and put it on the screen and take a spray  
9 gun and shoot it with particles. That would be  
10 conservative, and then work yourself back.

11 There's no modeling at all. There's  
12 absolutely no understanding how these pieces come  
13 together. They just -- they're somewhere there, but  
14 you know, there's some insight.

15 Well, I have absolute zero insight as to  
16 how these things go together. So I know you have a  
17 lot of flow area, and that's good, but that clearly is  
18 not sufficient.

19 Now, with regard to another comment I made  
20 last time, it had to do with flow acceleration and  
21 corrosion. I think answers were clear. The gentleman  
22 that was sitting here asked the question, and the  
23 question was answered with regard to velocity and the  
24 fact that you're going to increase the scope of your  
25 inspection probably will take care of it, but it is a

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1 potential problem because you're running 100 feet or  
2 200 feet per second with some particles in there. So  
3 basically, these are the four issues that I am sort of  
4 repeating myself.

5 CHAIRMAN DENNING: Do we have any  
6 questions?

7 Let me ask one question, and that is with  
8 regard to your first concern, which is in additional  
9 accident loads, it looked to me like as far as local  
10 loads that they really aren't changed very much, and  
11 I was wondering whether, you know, it was EPU or  
12 whether it's -- that even though the power is up, the  
13 blow-down looks awfully similar, and I was just  
14 wondering was there a particular accident scenario  
15 that was of concern to you that would --

16 MR. HOPENFELD: Well, I think I just went  
17 on a gut feeling that we are talking about increasing  
18 power. I know you're going to be choked on one side,  
19 but as it was pointed out, you're going to run in for  
20 a long period of time.

21 Really the question is: are you going to  
22 excite some new vibrations in that dryer during that  
23 different conditions? And you've got to address that.  
24 Because if you do, there was a case. I forgot where  
25 it was in Florida. I just don't remember the case,

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1 where we did have, I think, a valve on the main steam  
2 line lifted and excited very, very strong vibrations.

3 So you've got to look at it. You just  
4 can't say it's not there. How different it is, I  
5 mean, the flow is choked, and I don't know what the  
6 peer does to it, but I think you have to realize  
7 really again going back to what the calculations tell  
8 you.

9 The calculations we had 40 years ago are  
10 not that good, again, based on the PWR. If you go  
11 into more detailed modeling, you may find out.

12 I don't know how the temperature is  
13 affecting it. Temperatures may not be different, but  
14 the natural frequency of the dryer may change, too.  
15 So how to hold that thing together, somebody has got  
16 to look, and I haven't even heard it mentioned to you  
17 running into PRA and CDF, but you've got to address  
18 the physics first.

19 CHAIRMAN DENNING: Thank you very much.

20 PARTICIPANT: Are there anymore comments?

21 MR. ATHERTON: My name is Peter James  
22 Atherton. I'm here primarily representing the  
23 interests of the public.

24 And I have a few comments I'd like to  
25 make, and I'll start out with an overview that has me

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1 concerned, and that is the present state of NRC safety  
2 culture.

3 I was involved in a 2206 petition on a BWR  
4 in which the response ultimately, which went to the  
5 Commissioner level, was that -- and this was put in  
6 writing -- was that there was their opinion that there  
7 would not be an accident at a boiling water reactor,  
8 and therefore, the safety concerns that I addressed at  
9 that time were not considered to be significant.

10 And if that's a prevailing attitude within  
11 NRC as a result of this higher management posture, I  
12 have concerns about, you know, how this propagates  
13 into a safety culture. I realize it's obvious to me  
14 that you have engineers from General Electric and  
15 Vermont Yankee are quite competent, and they do the  
16 design work in trying to make the plant function at a  
17 higher power level, be it more efficient so to speak,  
18 which is, you know, what an engineer tries to do for  
19 money making purposes, and so they do have some  
20 control over the equipment that they operate and  
21 handle, design and use for all practical purposes.

22 They, however, don't have control over  
23 some things like environmental issues and disgruntled  
24 employees, and the unmentionable, the terrorist act.  
25 And these can have an effect upon the operation of the

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1 plant in a negative way.

2 And so I'm concerned about the safety  
3 culture that NRC propagates in this manner to people  
4 that I've interacted with.

5 Another overall perspective is safety  
6 margin. I used to work with the Nuclear Regulatory  
7 Commission and the old Atomic Energy Commission in the  
8 1970s, and there was significant safety margin, and I  
9 can't give you specific numbers to it, that plants  
10 were designed to, probably because of the unknown more  
11 than anything else.

12 What hasn't been made obvious to me at  
13 least in the presentation that I was permitted to be  
14 at yesterday and today was exactly what an acceptable  
15 margin is at least from a percent perspective, whether  
16 it be temp. to pressure or whatever, and the design of  
17 an equipment that would be considered acceptable.

18 For instance, I saw what appeared to be in  
19 a conflicting manner. I went over the areas of the  
20 submissions that the members of the public were  
21 permitted to have in the closed sessions, and I  
22 noticed, for instance, over pressure protection was  
23 cited to be 1328 psig and the limit established by  
24 some standard was 1375. That's getting very close to  
25 the limit in that area, and I just wondered what is

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1 acceptable.

2 CHAIRMAN DENNING: One thing you should  
3 recognize is that the ASME standard itself has a great  
4 deal of conservatism in it that we recognize. So it's  
5 not just that that's a safety limit.

6 MR. ATHERTON: I know, but why is it that  
7 NRC has not developed or devised a standardized safety  
8 margin for this, that or the other to which then  
9 either an exemption would have to be granted if the  
10 licensee or the utility or the plant owner, whatever  
11 they are nowadays, doesn't meet it as opposed to just  
12 coming up with something that creeps up on that limit?  
13 That's the point I'm trying to make.

14 And that perhaps would tend to approach  
15 the safety culture point of view from NRC's  
16 perspective.

17 I have a general question. I was involved  
18 with the weapons side of the nuclear fence, and at one  
19 of the sites that I was involved with they're doing  
20 kind of a retroactive look at to what radiation  
21 releases were from that site to the general public,  
22 and what has not been made clear to me through my  
23 participation over a matter of years with that group  
24 is what is an acceptable radiation release to the  
25 environment where an epidemiological study could

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1 provide some significant determination as to whether  
2 the public was adversely affected.

3 The health physicists have proposed a ten  
4 rem standard per year, if I recall correctly, and I  
5 was just perplexed because I was unaware of anybody  
6 who had a standard that they were going to use to cut  
7 off whether or not it would be worthwhile studying the  
8 adverse effects of radiation on the public or whether  
9 a study should take place.

10 And so I was interested in some feedback  
11 in that area at some point in time. If we are  
12 permitting 25 millirem per year radiation release to  
13 the general public as an acceptable limit and the  
14 public is not being significantly affected by ten rem  
15 per year release, why the conservativeness?

16 If it is, then that's a significant gap,  
17 from 25 millirem to ten rem by, you know, several  
18 orders of magnitude, and this is an issue that I think  
19 needs to be addressed in one way or another.

20 With regard to the issues that the public  
21 was shut out on, the computer codes, I'm obviously not  
22 able to determine separately as a member of the public  
23 whether these computer codes are properly verified by  
24 testing or some other means to determine that what  
25 they actually say in particular with particular inputs

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1 and with particular assumptions or what tests reveal  
2 fall within that range.

3 And so I have questions as to, you know,  
4 the applicability of these codes to this particular  
5 uprate.

6 At the beginning of the licensing of this  
7 nuclear power plant, Vermont Yankee, they had to have  
8 in those years, the late '60s and early '70s, a  
9 failure modes and effects analysis, which is a  
10 rudimentary way of determining what the design  
11 criteria would be.

12 Nobody has addressed this failure modes  
13 and effects analysis to what specific accidents were  
14 looked at, what they came up with back then and then  
15 what the power uprates' effects are going to be upon  
16 that today, and I would ask why.

17 I would also concerning probabilities, and  
18 I have asked this on a number of occasions and I to  
19 this date haven't received an adequate reply. We have  
20 probabilities. In the early days it was failure  
21 rates. In order to predict how long a piece of  
22 equipment would operate, we had simple probabilities  
23 that we would use to determine that. It has now  
24 become a field of its own.

25 When I asked the question that to me would

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1 help put this probability scenario into perspective,  
2 I go back to TMI, for instance, and I will say: the  
3 Three Mile Island accident Unit 2 in 1979, what was  
4 the probability that that accident occurred in the  
5 manner in which it occurred? What would be the  
6 probability of that happening?

7 And probably a year later I got some  
8 feedback from somebody who was a manager today who was  
9 involved with those earlier computations at that  
10 time, and I'm going to say this, although he gave it  
11 to me in a private manner. He said the probability of  
12 that accident happening was close to ten to the ninth  
13 or one over ten to the ninth. Excuse me.

14 That's -- you know; yet it did happen, and  
15 we're using numbers of Reg. Guide 1.147 has ten to the  
16 fourth, ten to the fifth. We're not looking at the  
17 failure rates of steam dryers. What's the probability  
18 that a steam dryer's failure rate is going to be such  
19 that what happened at Quad Cities or what is happening  
20 at other plants would have happened?

21 And what is the probability, if we're  
22 looking at probabilities, what is the probability that  
23 that failure rate is going to occur with the beefed up  
24 design at Vermont Yankee?

25 And what would be the potential

1 consequences if it did occur?

2 And I haven't seen people look at this  
3 situation from that point of view.

4 I had an occasion when I was requested to  
5 do so to look into the seismic criteria at Vermont  
6 Yankee, and not from the NRC, but from the output from  
7 another agency it appeared that the 24-year maximum  
8 probable earthquake was in the neighborhood of .3G's  
9 ground acceleration.

10 And when I looked at the criteria that  
11 Marty Stutzke, if I'm pronouncing his name right -- he  
12 has indicated that the plant was designed to something  
13 like .07G, an operating basis earthquake. I'm  
14 assuming that's a ground acceleration, and the safe  
15 shutdown earthquake to .14G versus the maximum  
16 probable earthquake over a 2,400-year period being  
17 .3G, and I'm saying why. What happened to the  
18 design, you know, for the maximum probable earthquake?

19 And then he goes forth and describes the  
20 fact that it looks like the main coolant system would  
21 be able to withstand something greater than point, G,  
22 which makes that point somewhat moot at least  
23 probabilistically, but then I happen to know that the  
24 stand alone devices, the structures, the things like  
25 water tanks, storing lots of water, hundreds of

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1 thousands of gallons of water, pipes, underground  
2 pipes, cooling towers to the extent that they're not  
3 independently seismicly qualified; would they be  
4 capable of withstanding this maximum earthquake?

5 And I haven't seen a response to that.

6 I also was involved with a Taurus  
7 (phonetic) problem at another BWR in which the Taurus  
8 apparently either jumped or was fearful of it having  
9 moved in some way, shape, or form during a blow-down  
10 incident that this plant had. And there was  
11 sufficient concern that -- this was only a few years  
12 ago, in the neighborhood of five or five to six, seven  
13 years ago -- and there was sufficient concern with  
14 this situation such that during the refueling outages  
15 they put saddles on the Taurus to try to keep it from  
16 moving and thereby keep it hopefully intact.

17 I haven't heard this subject addressed at  
18 Vermont Yankee, and I don't know what the situation is  
19 like there.

20 This same plant also had a core shroud  
21 problem, a cracked core shroud. Whereas foreign  
22 countries that I know of with the same type of problem  
23 have replaced the shroud, this plant chose to patch  
24 it, and I understand that there are other plants, and  
25 if I'm correct, Vermont Yankee also has a patch on a

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1 core shroud.

2 I haven't heard that addressed and what  
3 the effects of that patch would be with the uprate and  
4 how that patch has operated over the course of the  
5 time that it has been in place.

6 And I got the impression from Mr. Stutzke  
7 being up here that he had some requests for additional  
8 information out to the licensee and presumably there  
9 is going to be a final presentation to the full  
10 committee, and I can't help but get the impression  
11 that this safety issue is being time constrained, and  
12 that in the rush to get answers towards the end, they  
13 have scheduled something ahead of time which, I  
14 believe, as you mentioned, sir, there might be too  
15 many loose ends at that time.

16 I'm just curious as to why these loose  
17 ends would not be, let's say, properly addressed at  
18 least by this point in time rather than have it go  
19 forward to the point where the full committee would  
20 have to deal with this.

21 And so I get the impression as an outsider  
22 that time management is more important than safety,  
23 and I could be wrong, but this is a concern to me as  
24 a member of the public. And I would ask that perhaps  
25 you look into that situation as to why we still have

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1 outstanding issues in a matter that's coming to the  
2 full committee for hearing and whether maybe that full  
3 committee meeting maybe wouldn't be proper to postpone  
4 that until these issues were properly addressed.

5 And I thank you for permitting me to make  
6 these comments.

7 CHAIRMAN DENNING: Thank you very much.

8 MR. ATHERTON: Are there any questions?

9 CHAIRMAN DENNING: Any comments,  
10 questions?

11 (No response.)

12 CHAIRMAN DENNING: Thank you.

13 Are there any other members of the public  
14 that want to make a presentation? Yes, please.

15 MR. SHADIS: Good afternoon. My name is  
16 Raymond Shadis. I'm representing New England  
17 Coalition.

18 Thank you for the opportunity to comment.  
19 I'll try to make this quite brief. As I remarked to  
20 one member of the committee earlier today, there's too  
21 much to say. So I'll be brief. We will try to  
22 provide some additional written comments, and I'll try  
23 to do that in outline form so that they're accessible  
24 and usable for your purposes.

25 I would like to comment, and I hope that

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1 the committee in its review will comment on the  
2 process. There are all of the technical specifics,  
3 and there are a number of things that jumped out  
4 today, but largely the great concern here is with the  
5 process.

6 From October, beginning of October  
7 forward, it really seemed as if the technical review  
8 was being driven by a calendar that was set for  
9 reasons other than technical review. We suddenly had  
10 proposed dates for ACRS to review this project, and a  
11 last minute rush of RAIs and SER and, you know, we're  
12 really not done with that process yet.

13 And it does seem to be backwards, that all  
14 things considered, if safety were the first concern,  
15 that that first concern for safety would have it that  
16 as the technical issues were resolved, the calendar  
17 would then be set in accordance with anticipating the  
18 end of resolving those issues, not the other way  
19 around.

20 So there's that comment. Also, one thing  
21 that popped out today, earlier today, was the  
22 segmented licensing actions that have gone forward in  
23 support of EPU. In June of -- yeah, I think it was in  
24 June, late spring of 2003, we have copies of NRC staff  
25 correspondence wondering if it is valid for this

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1 licensee to separately submit their ARTS MELLA  
2 (phonetic) application, their AST application, and the  
3 extended power uprate application, and whether or not  
4 for legitimate consideration they should not all have  
5 been submitted together.

6 When we had a presenter from NRC today  
7 talking about the alternate source term credit for dry  
8 well spray capture of Iodine 131, one of the committee  
9 members put their finger right on it because, hey,  
10 wait a minute. We're taking credit for using this  
11 spray system. On the other hand, we have some  
12 constraints about not using it. You know, this is  
13 among one of those many little issues that's got to be  
14 floating around in the mind of an operator.

15 Comes the time when you are under accident  
16 constraints, and had AST and the EPU been handled  
17 together in one application, people might have meshed  
18 those two concerns and properly addressed them, and I  
19 guess our concern is how many other technical issues  
20 are floating out there where there is conflict and  
21 contradicting information that is bouncing around  
22 among these three different applications.

23 And I just very quickly want to comment on  
24 one other item that you have all been asked to  
25 consider by the State of Vermont initially, and that

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1 is the State of Vermont in requesting an independent  
2 engineering assessment of Vermont Yankee as  
3 prerequisite to upgrade stated that in their letter of  
4 request, their belief that the ACRS would consider any  
5 such examination in the course of its review of the  
6 uprate.

7 And I know that you've gone there, given  
8 that you scheduled that into the two meetings that you  
9 held in Brattleboro.

10 I just want to give a little background on  
11 the origin of that engineering team inspection that  
12 NRC offered as a substitute for the independent  
13 engineering assessment that was requested by the  
14 Vermont Public Service Board. This is SECY Letter  
15 040071, dated April 29th, 2004, and this letter  
16 spells out the proposed program for the engineering  
17 team inspection. It is entitled "Proposed Program to  
18 Improve the Effectiveness of Nuclear Regulatory  
19 Commission Inspections of Design Issues."

20 And this is from William Travers,  
21 Executive Director of Operations. And Mr. Travers  
22 reports that in order to better understand the degree  
23 to which NRC inspections and licensee self-assessment  
24 efforts have been effective in identifying design  
25 issues, the staff reviewed the last three years of

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1 data from the reactor oversight process, and here's  
2 what he says. And I think it's interesting; it's  
3 instructive.

4 "Of the 17 greater than green design  
5 engineering issues that fell within the scope of this  
6 review, 11 were NRC identified, two were licensee  
7 identified, and four were self-revealing." Love it.

8 "Of the 11 NRC identified issues, seven  
9 involved issues that had previously been recognized by  
10 the licensee, but whose significance the licensee had  
11 not recognized. Three of the NRC identified issues  
12 were associated with fire protection, an area not  
13 typically covered in NRC design inspections. Only one  
14 of the NRC identified issues was identified as a  
15 result of an NRC design inspection."

16 And it takes me back to parochial school  
17 when we had to do all of the taking away and putting  
18 back of numbers in any sequence. If we had the  
19 blackboard up here, we could come down and understand  
20 that of 17 greater than green design engineering  
21 issues, only one was identified as a result of an NRC  
22 design engineering inspection.

23 So does the program need improvement is  
24 the question they were trying to answer, the question  
25 they were struggling with.

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1                   Now, the scale of the independent  
2 engineering assessment requested by the State of  
3 Vermont was for four people, four weeks, or about 640  
4 hours of inspection time, and in this letter with  
5 respect to the proposed engineering team inspection,  
6 Mr. Travers reports, "Overall, the prototype  
7 inspection module is more resource intensive and would  
8 require about 700 hours of direct inspection versus  
9 the current allocation of approximately 500 hours for  
10 the safety system design inspection."

11                   And it doesn't take very long in thinking  
12 about it before one realizes that the inspection that  
13 was done wrapped in the routine periodic design basis  
14 inspection, the one that yielded one finding in 17,  
15 that same inspection.

16                   So where Vermont was asking for inspection  
17 on the scale of 640 hours, here we have NRC proposing  
18 to give them 200 hours of specialized inspection added  
19 to the normal 500 hours that they do. The 500 hours  
20 is taken off the board, and what is put back on is  
21 700. So basically a net gain of 200 hours.

22                   On July 1st, 2005, SECY Paper 050118 was  
23 issued by Luis Reyes, Executive Director, and again,  
24 it is instructive, and it goes eventually right to  
25 this EPU review, my humble opinion.

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1           The results, and he's speaking now about  
2           four pilot inspections that were done, and Vermont  
3           Yankee was one of those pilot inspections. "The  
4           results of the pilot inspections appear to indicate  
5           that latent design and engineering issues mostly of  
6           very low safety significance persist at operating  
7           reactors. The pilot inspections resulted in 29  
8           inspection findings."

9           And to Vermont Yankee, the next page, "the  
10          staff has reviewed the results of the Vermont Yankee  
11          inspection and has concluded that the current power  
12          uprate inspection procedure should be enhanced. In  
13          addition, a process should be developed to better  
14          integrate the inspection and NRR technical review  
15          process for power uprates and other important license  
16          amendment requests. These conclusions are based  
17          primarily on the identification of several issues  
18          during the Vermont Yankee inspection. These issues  
19          included the acceptability of the licensee's power  
20          uprate submittals with respect to station blackout  
21          rule, motor operated valve testing, certain operator  
22          response times, and certain assumptions in accident  
23          analyses. The staff believes it unlikely that these  
24          inspection identified issues would have been  
25          identified by subsequent NRR technical reviews

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1 because" -- and this echoes the last two days because  
2 I heard this, and this is parenthetical and I'm  
3 interjecting this.

4 Over the last two days, I heard NRC staff  
5 say again and again "the licensee says," "the licensee  
6 reports," "the licensee tells us," "the licensee has  
7 it in their application."

8 "The staff believes it unlikely that these  
9 inspection identified issues would have been  
10 identified by subsequent NRR technical reviews because  
11 the NRR technical reviews rely primarily on licensee  
12 submitted documentation."

13 And this I could have written myself.  
14 "The staff, therefore, believes that a detailed  
15 inspection is a good complement to the NRR technical  
16 review in this area."

17 Finally, there is a table included in  
18 Attachment 2 of that letter, and it yields that  
19 Vermont Yankee was accorded a total of 910 hours of  
20 direct inspection. This is an addition of 410 hours  
21 not to the nominal 500 that's part of the vanilla  
22 periodic inspection.

23 So what the State of Vermont asks for was  
24 a very special inspection to confirm the conditions of  
25 the plant, to provide some indication of future plant

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1 reliability, to confirm, I think -- maybe I'm putting  
2 a little interpretation on this -- to confirm NRC's  
3 assumption that their normal inspection regimen  
4 provides sufficient assurance that the plant is in  
5 conformance with its design basis.

6 And what they got instead was a warmed  
7 over portion of their normal inspection regimen with  
8 a topping, if you will, and definitely not what they  
9 requested.

10 I will be submitting written comments  
11 because there is additional material with respect to  
12 the contrast between the scale and the scope and the  
13 purposes of the requested independent engineering  
14 assessment and what NRC finally gave us, which was the  
15 engineering team inspection, and I will persist in  
16 that until I convince you gentlemen to reject the  
17 notion that these two are somehow equal.

18 Finally, just a couple of quick points.  
19 A number of the presentations that were given, there  
20 was an admission or it could be easily derived that  
21 safety margins, while they may not have been or may  
22 not be eroded beyond what regulation provides for, are  
23 nonetheless eroded, diminished, and where this is a  
24 matter of public concern, it is truly disconcerting to  
25 see all of those diminutions at almost every turn and

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1 facet stack up.

2 In terms of a trend, you would have to  
3 say, as far as a safety trend, it is a negative trend  
4 that has been incorporated in this application.

5 Earlier today one of the NRC presenters  
6 referenced the off-site dose calculation manual and  
7 referred to the numbers for fenceline dose as a result  
8 of the shortened time of passage for N-16 through the  
9 loop and resulting shine in fenceline dose.

10 And I don't remember the exact numbers he  
11 used, but it looked to me like he was saying the base  
12 fenceline dose from which Vermont Yankee was moving  
13 was about 15 MR per year, and that after uprate, they  
14 were looking at about 18.6. I think those were the  
15 numbers he used.

16 And this is an issue that we reviewed  
17 because the State of Vermont has an agreement with  
18 Vermont Yankee in which Vermont Yankee agrees to  
19 comply with state regulation of 20 MR at fenceline, 20  
20 MR per year, and when we first looked at the proposed  
21 uprate, the numbers we got went beyond the 20 MR.

22 but then what happened very quickly was  
23 that at Vermont Yankee they reached back into some NRC  
24 guidance which permitted them to adjust the calculated  
25 dose at fenceline, and what it is is a quality factor

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1 which they now applied on the difference between skin  
2 dose and air dose or between -- turn that around --  
3 between air dose and skin dose, between rads and rems.

4 And whereas this has been traditionally  
5 treated as a one-one equivalency, there's now in place  
6 a .71 quality factor. So I'm not arguing with the  
7 numbers they gave you, but if it's 18.6, they arrived  
8 at that by applying for and taking credit for and  
9 using this .71 quality factor.

10 To the citizen walking by, what that looks  
11 like is a 29 percent discount in order to facilitate  
12 uprate. What wasn't mentioned is that we're now  
13 looking at the deployment of dry cask storage, and  
14 whatever little incremental dose can be expected from  
15 that will, of course, be added. That is now a matter  
16 of some contention.

17 The same thing is true, of course, in  
18 terms of the alternate source term and control room  
19 habitability issues. NRC offered its licensees the  
20 option of applying certain source term credits many  
21 years ago and Vermont Yankee never saw the need until  
22 they got ready to apply for extended power uprate, and  
23 then suddenly that long list of credits that was hung  
24 on the screen here when NRC staff did their  
25 presentation popped up.

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1                   And so it essentially is a 40 percent  
2 discount of what would have been dose at the control  
3 room under accident conditions, and in order to  
4 facilitate uprate.

5                   These are but two examples out of many  
6 that are available, and we'll write you until you  
7 really won't want to open the envelopes, but these are  
8 two examples out of the many that are available of the  
9 way that the safety margins have been eliminated.

10                   And you know, we spoke in Brattleboro at  
11 least to some small degree about the removal of the  
12 old things that we used to rely on for redundancy, of  
13 defense in depth, of the individual integrity of  
14 individual safety systems. So, you know, we'll be  
15 bringing those to you, and I do thank you.

16                   I have a couple of quotes for you. I love  
17 these little quotes. EPA Chairman Ruckleshouse once  
18 said about risk assessment, and it could be as well  
19 applied to the PRAs, that it was like capturing an  
20 enemy combattant, and if you tortured him long enough,  
21 you'd get him to say anything.

22                   You know, we see that over and over. At  
23 my hotel room this morning, I lingered over a Christa  
24 McAuliff tribute, and that was the 1986 Challenger  
25 disaster. You know, PRA just didn't hack it there,

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1 and PRA I don't think would have predicted that since  
2 we began extended power uprate modifications at  
3 Vermont Yankee, we have had two generator trips and  
4 two scrams, and we have had reverberations throughout  
5 the system, recirc pump trips, various trips during  
6 one of those.

7 So bringing you those concerns. Any  
8 questions, gentlemen?

9 CHAIRMAN DENNING: Thank you very much.

10 MR. SHADIS: Thank you.

11 CHAIRMAN DENNING: We appreciate your  
12 input.

13 Okay. I would like to thank all of the  
14 contributors. I think that this has been an excellent  
15 meeting. I'd like to particularly thank Entergy for  
16 excellent presentations, their willingness to make  
17 modifications in their presentations, the staff also  
18 for excellent presentations. I thank the public for  
19 their comments.

20 And with that, I think we will adjourn.

21 (Whereupon, at 4:59 p.m., the meeting was  
22 concluded.)

23

24

25

**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 Upgrades

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  
Official Reporter  
Neal R. Gross & Co., Inc.

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## Entergy Vermont Yankee Extended Power Uprate

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Presentation to the  
Advisory Committee On Reactor Safeguards  
Extended Power Uprate Subcommittee  
November 30, 2005

1



## Flow Accelerated Corrosion Topics

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- o Program Overview
- o EPU Impact
- o Conclusion

2



## Flow Accelerated Corrosion Overview

---

- Programmatic Approach to Monitor FAC
  - Program Meets Generic Guidance
    - Generic Letter 89-08
    - 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



## Flow Accelerated Corrosion Overview

---

- Typically 25 to 35 Components Inspected Each Outage
- Repeat Inspections in Condensate & Feedwater show Minimal FAC Wear
- 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

---

- o 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

---

- o 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

---

- 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

---

- 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

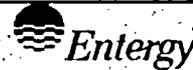


## Flow Accelerated Corrosion EPU Impact

---

- o Updating CHECWORKS Models with Recent Outage Inspection Data and EPU Parameter Changes for Performing Component Selection for RFO 26
- o 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



## Flow Accelerated Corrosion Conclusion

---

- o Minimal Changes in Existing FAC Wear Rates Expected with Implementation of EPU
- o No Impact on FAC Program Scope or Methodology
- o 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  $1.24 \times 10^{18}$  n/cm<sup>2</sup>
  - Fluence Calculation Updated for EPU
    - Increase RPV ID Fluence Rate (Flux) by 26%
  - RPV ID Surface Integrated Peak Fluence
    - CLTP -  $2.99 \times 10^{17}$  n/cm<sup>2</sup>
    - EPU -  $3.18 \times 10^{17}$  n/cm<sup>2</sup>
- TS PT Curves remain bounding for EPU operation



## 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



## 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<sub>2</sub>) Available
- PCIS Maintained

2

## 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

## 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



## 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

## 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

## 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

## 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

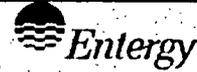
## Operator Actions / Timelines

---

- 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



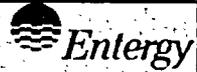
## VY PSA Overview

---

- 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



- 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

---



- Hardware Changes
- Procedural Changes
- Configuration Changes
- Power Level

3

## Probabilistic Safety Analysis

### EPU Impacts

---



- No New Accident Sequences Identified
- No Significant Impact:
  - IE Frequencies
  - Only One Success Criteria Change (1 additional SSV for ATWS)
  - Due to Hardware Changes
  - Due to Procedural Changes
- Slight Decrease in Time Available for Some Post-Initiator Operator Actions

4

# Probabilistic Safety Analysis

## ATWS Operator Actions



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



- o Level 1 & 2 Internal Events (Quantitative)
- o External Events (Qualitative)
- o Shutdown Events (Qualitative)

6



## Probabilistic Safety Analysis

### Conclusions

---

- Very Small Risk Increase (CDF)
  - $\Delta\text{CDF} = 3\text{E-}7/\text{ry}$
  
- Small Risk Increase (LERF)
  - $\Delta\text{LERF} = 1\text{E-}7/\text{ry}$
  
- No Significant Risk Impact from External Events and Shutdown