Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards 525th Meeting
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Thursday, September 8, 2005
Work Order No.:	NRC-592 Pages 1-264

NEAL R. GROSS AND CO., INC.
Court Reporters and Transcribers
1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

525th MEETING

+ + + + +

THURSDAY,

SEPTEMBER 8, 2005

+ + + + +

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

MEMBERS PRESENT:

GRAHAM B. WALLIS

Chairman

WILLIAM J. SHACK

Vice-Chairman

GEORGE E. APOSTOLAKIS

ACRS Member

RICHARD S. DENNING

ACRS Member

THOMAS S. KRESS

ACRS Member

MARIO V. BONACA

ACRS Member

DANA A. POWERS

ACRS Member

JOHN D. SIEBER

ACRS Member-at-Large

ACRS STAFF PRESENT:

SAM DURAISWAMY

ACRS Staff

JENNY M. GALLO

ACRS/ACNW Staff

JOHN T. LARKINS

Executive Director, ACRS/ACNW,

Designated Federal Official

CAYETANO SANTOS, JR.

ACRS Staff

MICHAEL L. SCOTT

ACRS/ACNW Staff

ASHOK C. THADANI

Deputy Executive Director, ACRS/ACNW

NRC STAFF PRESENT:

TOM ALEXION

NRR/DLPM/PDII-1

KIRSI ALM-LYTZ

NRR/IPSB

RAJ ANAND

NRR/DRIP/RNRP

RALPH ARCHITZEL

NRR/DSSA/SPLB

RAJENDER AULUCK

NRR/DRIP/RLEP/RL

JUAN AYALA

NRR/DRIP/RLEP

WILLIAM BECKNER

NRR/DRIP/RNRP

THOMAS CHENG

NRR/DE/EMEB

PAUL CLIFFORD

NRR/DSSA/SRXB

DAVID CULLISON

NRR/DSSA/SPLB

YAMIR DIAZ

NRR/DE/EMCB

LAURA DUDES

NRR/DRIP/RNRP

JOHNNY EADS

NRR/DRIP/RLEP

BARRY ELLIOT

NRR/DE/EMCB

NRC STAFF PRESENT:

RICH ENNIS

NRR/DLPM

TANYA FORD

NRR/DSSA/SRXB

QI GAN

NRR/DRIP/RLEP

THOMAS HAFERA

NRR/DSSA/SPLB

BRAD HARVEY

NRR/DSSA/SPSB-C

STEVE HOFFMAN

NRR/DRIP/RLEP

CORNELIUS HOLDEN

NRR/DLPM

JOHN HONCHARIK

NRR/ADPT/DE/EMCB

KAIHWA HSU

NRR/DRIP/RLEP

CHRISTOPHER JACKSON

OCM

JOHN JOGLEWEDE

RES

ANDREA KEIM

NRR/DE/EMCB

MARGIE KOTZALAS

NRR/DSSA/SPSB

MARK KOWAL

NRR/DSSA/SPLB

TOMMY LE

NRR/RLEP

SAMSON LEE

NRR/DRIP/RLEP

RIN SHEN LI

NRR/DRIP/RLEP-A

YONG LI

NRR/DE/EMEB

RICHARD LOBEL

NRR

SHANLAI LU

NRR/DSSA/SPLB

JOHN MA

NRR/DE/EMEB

L.B. MARSH

NRR/DLPM

RICHARD McNALLY

NRR/DE/EMEB

JAMES MEDOFF
NRR/DE/EMCB

NRC STAFF PRESENT:
ROBERT MOODY
USIR/DPR/EPD
CLIFF MUNSON
NRR/DE/EMEB
SAIWAH NG
NRR/DRIP/RLEP-A
VIJAY M. NILEKANI
IAC
NITIN PATEL
NRR/DRIP/RNRB
ROBERT PETTIS
NRR
DARRELL J. ROBERTS
NRR/DLPM/PDI-2
VERONICA RODRIGUEZ
NRR/RLEP
MARK RUBIN
NRR/DSSA/SPSB
FARIDEH SABA
NRR/DLPM/DP2-1
JOHN SEGALA

NRR/DRIP/RNRP
MICHELLE SNELL
RES
MARTIN STUTZKE
NRR/DSSA/SPSB
RAMACHANDRAN SUBBARATNAM
NRR/DRIP/RLEP
SHERWIN TURK
NRC/OGC
KATHY WEAVER
NRR/RLEP
GREG WERNER
NRC/OCM/PBL
OH YEE
NRR/DRIP
JAKE ZIMMERMAN
NRR/DRIP/RLEP

ALSO PRESENT:
PAUL AITKEN
Dominion

DON ANDERSON

CH2M Hill

RUSS BELL

NEI

MIKE BILLONE

ANL

MICHAEL CAMBRIE

WorleyParsons

GORDON CLEFTON

NEI

ALLIN CORNELL

CAC Co.

STEVEN DOLLEY

Inside NRC - Platts

STEVE FRANTZ

Morgan Lewis

EDDIE R. GRANT

Exelon

KATHRYN L. HANSON

Geomatrix Consultants

TOM HENDY

Dominion

BRENDAN HOFFMAN

Public Citizen

SARAH HOFMANN

VT Dept of Public Service
BERNIE HOLCOMB
CH2M Hill
JERRY HOLM
Framatome ANP
MARC HOTCHKISS
Dominion
JOHN IOANNICH
WorleyParsons
ROBERT KENNEDY
RPK Structural Mechanics
J.E. KNORR
NMCLLC Point Beach
GARY KOMOSKY
Dominion
MARILYN KRAY
Exelon
DAVID KUNSEMILLER
FENOC Beaver Valley
DAVID LOCHBAUM
Union of Concerned Scientists

ALSO PRESENT:
BILL MAHER
Exelon

DAVID MITCHELL
Westinghouse
TOM MUNDY
Exelon
MITCH NISSLEY
Westinghouse
JERRY POTTS
GNF
ROGER REYNOLDS
AREVA
DOUG ROSINSKI
PWSP
ROGER RUCKER
First Energy
RICHARD SCHOFF
Westinghouse
WILLIAM SHERMAN
VT Dept of Public Service
CHARLES SORRELL
Dominion
CARL STEPP
EHS
GREGG SWINDLEHURST
Duke Power
BILL WATSON

Dominion

JENNY WEIL

McGraw-Hill

TOMOHO YAMADA

JNES

ROSA YANG

EPRI

ROBERT YOUNGS

Geomatrix Consultants

AGENDA ITEM PAGE

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

(8:30 a.m.)

VICE CHAIRMAN SHACK: The meeting will now come to order. Chairman Wallis is a little bit delayed, so we're going to be starting the meeting without him. We expect to see him later on today. This is the first day of the 525th meeting of the Advisory Committee on Reactor Safeguards.

During today's meetings, the Committee will consider the following: a final review of the license renewal application for Millstone Power, Units 2 and 3; interim review of the Exelon/Clinton early site permit application; Proposed Revision 4 to Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident"; possible alternative embrittlement criteria to those in 10 C.F.R. 50.46; and preparation of ACRS reports.

This meeting is being conducted in accordance with provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the Designated Federal Official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions. I don't believe that's true. We have a - it's on the agenda, so there will be a public comment on the Millstone license renewal.

A transcript of portions of the meeting is being kept and it is requested that speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

I will begin with some items of current interest. On behalf of the Committee, I would like to congratulate Dr. Apostolakis, who received the Arthur Holly Compton Award in Education at the 2005 ANS Meeting. This award is in recognition of his development of innovative ways to educate students and professional engineers in the art and science of PRA and other occult arts.

I would point out for the members that we do have some items of interest, including some speeches from members of the Commission. One particular item that they may be interested in the items of interest is the agenda for the upcoming CSARF meeting, which starts on Page 76, and members may be interested in attending that.

I would also like to remind the members

that we are going to be interviewing candidates during lunchtime today and we'll try to stick to our schedule and be prompt, because we do have to make sure that we have time to carry this out.

Our first item of business today is the license renewal for Millstone, and I'll turn it over to Jack Sieber, who's Chairman of that subcommittee.

MEMBER SIEBER: Okay, thank you, Mr. Chairman. As you can see, my coffee cup has sprung a major leak here and so I'm in the process of cleaning up.

I would point out, however, that our Subcommittee on License Renewal has met and reviewed the submittal and the safety evaluation report for Millstone Nuclear Power Station, Units 2 and 3, and today, the applicant and the staff will meet with the full ACRS Committee to make a final judgment as to whether license renewal should be granted for these two units.

We will hear presentations from both the applicant, Dominion Connecticut, and the staff, and in addition, Ms. Nancy Burton of the Connecticut Coalition Against Millstone will address us for a few minutes via telephone.

With that, what I would like to do is

introduce Frank Gillespie, who will give us a little bit of background on the - yes?

MEMBER BONACA: Before that, I would like to point out that I did not participate in any of the subcommittees, nor will I contribute to this meeting in that I am conflicted on this application.

MEMBER SIEBER: Okay, thank you. With that, I'll introduce Frank Gillespie.

MR. GILLESPIE: Okay, Jack, thank you. Millstone is kind of a unique plant, and let me just highlight a couple issues. They were really our fourth pilot on what you're going to hear about tomorrow morning.

We had three official pilots on updating all of our guides, which was a major mid-course correction, and we were kind of just in the middle of trying to do what we were trying to do, and we weren't sure what it was at the time, but we figured it out later.

Millstone was nice enough, if you would, to, on their own, go back and look at all the past precedents that might have applied to their application. It was an extensive effort with some expenditure of resources beyond what other applicants have done to basically help improve the system. And they were coming off Surry and North Anna, so they had a good database to fall back on.

I would like to kind of officially, at this point, since Millstone's here, thank Dominion for that effort and it was a direct contribution and a major piece of the stepping-off point for the presentation the Committee's going to hear tomorrow on GALL, SRP, and the basis documents, so I thank them for that.

The other thing that was kind of unique about this was they actually came up with a method which other people have actually been copying on anchor points for A over 2 or non-safety piping systems.

So there was actually some good engineering and a little bit of innovation in the Dominion effort. Again, I think the subcommittee was, I hope, favorably taken with them and can make a good recommendation to the full committee. It's a utility that kind of went the extra mile with the staff on some specific engineering points, as well as the general thing.

With that, and having been able to say thank you, let me ask - Millstone's going to go first, and Bill Watson will be doing the presentation, and then Johnny Eads, the PM for Millstone, will be going second with the staff's presentation. Bill?

And I will apologize for P.T. not being here. P.T. is wrapped up right now in the conflict between advanced reactors and renewal relative to things like ESPs, and I think this week he's out talking to Argonne to line Argonne up to help us on environmental reviews, so we don't slip any ESPs in the future.

MR. WATSON: Good morning. My name is Bill Watson and I'm the supervisor of license renewal for Dominion at the Millstone Power Station. I'm also here today with Paul Aitken, who is the supervisor for license renewal for all of Dominion, out of our Innsbrook offices in Virginia.

We also brought with us team members Marc Hotchkiss, Charlie Sorrell, Gary Komosky, and Tom Hendy, to assist us in various areas where needed. These are the topics I plan to discuss or present to you today.

First, I'll give a brief description of Millstone 2 and 3 Power Plants, just to get everybody oriented to the topic. Then I'll present plant performance and operating history, and this includes any major plant equipment that has been replaced or is planned to be replaced in the future. Then I'll discuss the license renewal application a little bit.

We did have to apply for and we were granted an exemption from the requirements of 10 C.F.R. 54.17(c) because Millstone 3 did not have 20 years - very, very close, 18 1/4 years, but not quite 20 years - of operating experience prior to submitting our applications.

Then I will discuss the corrective action process, as requested by this Committee; present how we plan to address license renewal commitments - and we believe we have a very good story there and a good strategy for addressing these commitments and ensuring that they do not get lost and that an inspector can come in from any time from this point forward and know where we stand with those commitments.

MEMBER APOSTOLAKIS: Why couldn't you wait for 20 years? I don't understand why you had to rush.

MR. WATSON: The reason we did that is that we were going to go for license renewal for Millstone Unit 2. That's a very big effort. We have to assemble a team and do all that, and so it made sense to us that rather than to get through Unit 2, come down, and then have to rebuild the team again, it just made more sense to do that at the same time. And it was better for the staff, too, as well, to review it all at the same time.

Finally, I will discuss license renewal implementation, what we have done to date and where we are headed, and that also includes where we stand with commitments at this point in time.

First up, Millstone Unit 2 has a combustion engineering supply NSSS. It's a two-loop design, two steam generators and four reactor coolant pumps. The architect engineer is Bechtel Corporation. Initial operations began in 1975 and the electrical capacity is 895 megawatts-electric (MWe).

Millstone Unit 2 did have a power uprate in 1979. It was originally a 2,560 megawatt-thermal, 865 megawatt-electric plant. We did have an extended power uprate in 1979 that brought it to the current 2,700 megawatts-thermal and 895 megawatts-electric.

Millstone Unit 3 has a Westinghouse NSSS four-loop design with four recirculating steam generators and four reactor coolant pumps. The architect engineer was Stone and Webster Engineering Corporation. It began initial operations in 1985, ten years after Millstone Unit 2, and the electrical capacity is 1,195 megawatts-electric. It has not had a power uprate yet, and we're looking at that in the future, but that's basically just an economic decision, of course, at this point.

I’m going to stand up for a minute, but I'll project so I can be heard on the microphone. I just want to orient you. This is a picture of the site, the Millstone site. To the left is north, to the right is south. Obviously, then, up top we've got east, and down below we have west.

This Millstone station is located on the southern shore of Connecticut, which is the northern shore of Long Island Sound. On the eastern side - if you just go from south to north, we have the Unit 1 turbine building, Unit 1 reactor building, Unit 2 turbine building, Unit 2 reactor building, Unit 3 turbine building, Unit 3 reactor building.

You can see on the eastern side is our plant vent stack. What's off the diagram, way to the south at the tip, is our mech tower. On the southeastern portion of the site, we have the Unit 1 intake structure, the Unit 2 intake structure, and the Unit 3 intake structure, but there's a combined outfall on the south side of the site. In the northeast corner, you can just sort of see a little bit of it there, is the switch yard, and then what you can't see, down below and to the west, is Niantic Bay.

Operating history for the Millstone plant. I think most people are familiar with our shutdown that we had for Unit 2 and Unit 3 in 1996. Unit 2 came back up, after that extended shutdown, in 1999 and Unit 3 came up in 1998.

This is the history for the past five operating cycles. We have for Cycle 14, 95.6 percent capacity. Cycle 15 is 92.4. Cycle 16, 98 percent. Cycle 17, which we're currently in, 98.2 percent capacity. For Millstone Unit 3, Cycle 7, you have 98.7 percent capacity. Cycle 8, 97.3. Cycle 9, 97. Cycle 10, which you are currently in, 96.1 percent capacity.

A little bit about Millstone Unit 2 operating history. Unit 2 has been operating for 115 days since the last refueling outage. As far as major plant equipment that's been replaced, the lower portions of the two steam generators were replaced with corrosion-resistant material - that's alloy 690 - and that includes the tubes and the tubesheets. That was done in 1992.

The reactor vessel head was replaced in this past outage that we had in the Spring of 2005, and our pressurizer is scheduled to be replaced in the Fall of 2006, and you might note that that's

Commitment No. 36. We were doing this anyway, not associated with license renewal. We needed to replace our pressurizer. However, we were asked to make the commitment as part of license renewal as well, so we did. So that's Commitment No. 36.

Unit 2 - just note down at the bottom that Unit 2 does not have any bottom mounted instrumentation, so we don't have that issue to contend with on Unit 2.

Unit 3 has been operating for 132 days since the last unit shutdown. You may recall that we did have an automatic reactor trip in April as the result of tin whiskering in our solid state protection system.

The reactor vessel head is not currently scheduled for replacement. It is in the lowest susceptibility ranking and during a 2002 refueling outage, we did do a bare surface visual examination - it was a VT2 type examination, including all 78 CRDM penetrations. We did not find any evidence of leakage or cracking.

We will be required on Unit 3, however, to do either a UT or liquid penetrant or any current type testing of the nozzles as part of the order by February of 2008. Right now, currently, our thinking is UT would probably be the best way to go.

VICE CHAIRMAN SHACK: But on Millstone 2, you had a relatively low susceptibility and some cracking, correct?

MR. WATSON: That's correct. We are actually in the middle of - about middle of the pack, and we did have some cracking.

The bottom mounted instrumentation tubes were inspected. We had a bare metal visual examinations performed during the 3R09 refueling outage in 2004, and it was a hundred percent of the circumference of each penetration as it enters the reactor pressure vessel. We saw no indications of leakage or cracking. In fact, from this point forward, we will be doing a hundred percent inspection - bare metal inspection - of these tubes going forward at every refueling outage.

I do have to talk a little bit about Millstone Unit 1, because Millstone Unit 1 is permanently defueled, and for license renewal, we had to take a look at Unit 1 and see what the impact of decommissioning Unit 1 would be on Units 2 and 3 and what might need to be brought into scope for license renewal.

As I've noted on a slide, certain Unit 1 structures needed to be included in the scope of license renewal, namely the turbine building and the control room/radwaste - it's a combined building, the control room/radwaste treatment building.

Specifically, the Unit 1 turbine building provides structural load path for the flood boundary for protecting the Unit 2 turbine building. It also provides tornado, missile, hurricane, and weather protection for the Unit 2 turbine building and the Unit 1 control/radwaste building. Steel columns support the Unit 2 auxiliary building. It provides a structural load path for flood boundary protection for the Unit 2 turbine building and auxiliary buildings.

Then finally, the Unit 1 control room provides ingress and egress routes for the Appendix R event for most of Unit 2. So that's why those buildings need to be brought into scope for license renewal.

Also, certain Unit 1 fire protection equipment needed to be brought into scope. In fact, though, as part of the separation process, under the current decommissioning project, we needed to transfer some equipment over to Unit 3 that was originally Unit 1 equipment, and that's the diesel fire pump, the two fire water storage tanks, and the hydropneumatic, or the surge tank, basically, associated with the jockey pump. So obviously, those items needed to be brought into scope for license renewal.

Just a little bit about the license renewal application. The current operating license for Millstone Unit 2 will be expiring in 2015, in July of 2015, and Unit 3's will be expiring in November of 2025.

As I mentioned earlier, we did submit our applications for both units on January 22, 2004, and it required us to get an exemption from the requirements of 10 C.F.R. 54.17(c) because Millstone Unit 3 only had 18 1/4 years of operating experience.

The basis for that exemption request was that we had a lot of operating experience from Millstone Unit 1 and Millstone Unit 2, and we had the Surry and North Anna plants experience, being a Dominion facility, and we had the vast database from the GALL that we could look at, plus we could also look at other individual plants across the industry.

You could see that the vast majority of operating experience from Millstone 1 and 2 was directly applicable, because materials and environments and aging effects are materials and environments and aging effects.

However, as was pointed out at the last meeting, you may have some nuances with a particular design that you need to look at, and an example of that was the holddown spring for the Unit 3 reactor vessel.

Unit 1 and Unit 2 did not have a holddown spring, but Surry and North Anna did, so we brought that operating experience to the Millstone Unit 3 plant and we will be either testing for loss of pre-load on that holddown spring, or we will be replacing the holddown spring, and that is Commitment No. 14 in our application.

We did use the standard license renewal application format process. I kind of smiled a little bit because we were very heavily involved in the development of that format, so we stayed very pure to the format and we found that to be very helpful to us and, we feel, our interactions with the staff.

Also, we made extensive use of past precedents. As Frank mentioned earlier, that also was very beneficial to us. We did learn in the process. There were some areas where we looked at what was done at past plants and we found we could even improve upon that, and so we did.

We also participated in the consistent

with GALL audits, and I'd like to just say that we found those to be very beneficial, that face-to-face interaction with the staff was very, very valuable to us.

All right, I'd like to go on to describe our corrective action process. Of course, just like everyone else, we were required to have a corrective action process for 10 C.F.R. 50, Appendix B, XVI, that establishes the measures to be taken to ensure that conditions adverse to quality are promptly corrected and establishes measures to provide reasonable assurance that the cause of the condition is determined, corrective actions preclude repetition, and corrective action is taken in a timely and effective manner.

The way it works for Millstone is, as many other plants, we start out with a condition report, and a condition report can be written for any number of things. They can be written for just a question that someone has that they can't get an answer to, a problem that they identify, maybe even more significant problems.

It could be operating experience that we've gleaned from other plants in the industry, or our own operating experience to be shared across the site. Also, it could be results of benchmarking trips. It could be a trouble report, a broke/fixed type thing. Any of those items will result in the generation of a condition report.

Once that condition report goes into the system, it is reviewed by the on-shift STA, so all condition reports get reviewed by the on-shift STA for reportability concerns, safety concerns, and operability concerns.

If there are any of those three items that result, then the CRs will go right to the shift manager and the shift manager will initiate work orders to get action taken immediately, even before the CR is completely processed.

Whether or not it goes to the shift manager, all CRs go to a CR review team, which meets every morning. It's a multi-disciplined review team for all the disciplines across the site, and that team assigns a significance and investigation time and affected department - or I should say responsible department - for the CR.

Then the responsible department will make the assignment, assess the priority, and ensure that the particular assignment gets completed. Then the corrective actions department will review all closure notes for completed corrective actions and ensure that they agree that the corrective action was taken as noted in the closure notes and it does address the problem.

We did have an NRC inspection of our corrective action process in 2004, and they concluded that generally problems were properly identified, evaluated, and corrected.

They did not find a hundred percent across the board that being the case, so we did get two green findings, one in the area of - we had put pulsation dampers in on the discharge of our charging pumps in our CVCS, and we did not put a specific test on those pulsation dampers to monitor their condition over time. And the NRC felt that that would have been part of ensuring that set points were adequately translated from design controls into an actual implementation in the field.

We had another green finding where we had - and I think we talked about this at the ACRS subcommittee meeting - we had a safety injection tank - leakage of the safety injection tanks that we were tolerating for a long period of time, because it seemed to be of low priority to us, and they felt that that was not timely and effective corrective actions, which we agreed with.

Other than that, they found our program to be strong and robust. Then we had a Nuclear Oversite audit of our corrective action program and they concluded the same thing, that all regulatory requirements are being met.

MEMBER RANSOM: Out of curiosity, are either of these plants dependent on containment overpressure credit for meeting the NPSH requirements for the recirculation pumps?

MR. WATSON: Not to my knowledge. Did everybody hear that question from Dominion? Do either of these plants rely on overpressurization of containment to meet NPSH requirements for safety injection? I see heads shaking no.

Commitments. I know that's of great interest to this Committee and we think we have a good story here for you. The proposed commitments were submitted in the license renewal application and modified during NRC review. We actually started out with 26 commitments for both Unit 2 and Unit 3. On Unit 2, eight of those were modified and then we got 11 added as a result of the review. On Unit 3, nine were modified and 11 were added as a result of the review.

As you can imagine, for a site like Millstone, even though we have two separate NSSSs, we'd like to have all programs be as common as possible, and that's what we strive for. The result is, the vast majority of these commitments are the same for both units, but each unit has four unique commitments. In Unit 2, two of those are SAMAs. In Unit 1, one of those is a SAMA. By and large, the commitments are generally the same across both units.

Now, how we plan to treat these commitments, there will be a - the FSAR supplement will become a new chapter in the Unit 2 and Unit 3 FSAR; Chapter 15 for Unit 2, Chapter 19 for Unit 3. We have written the commitments right into this chapter of the FSAR, and there's a table right in the chapter of the FSAR that contains the commitments, and we will be treating these commitments as obligations under the current operating license, so - or obligations under the operating license.

What that means is, we would have to apply for an amendment to get a change to any of those commitments. That also means that from this point forward, once we actually do get our renewed operating license and add the chapters to the FSARs, from this point forward, any inspector can come in, open up our

FSAR Chapter 15 or 19, depending upon which unit they're on, and see our commitments.

In addition, we do not plan to remove those from the FSAR, so when they are completed, there is a status column in there that will show them completed. So the inspector will be able to see what commitments were exactly made for license renewal and what their exact status is at any point in time.

A little bit about license renewal implementation and, of course, how we're handling the commitments at this point in time, as well. We have - I guess I'd like to stress to this Committee that license renewal implementation has already begun at Millstone.

We learned from Surry and North Anna that it's good to start on license renewal right away, as they did, since it does take time to get cultures changed at a facility - or grown, in this case - the earlier, the better. So we've been providing training, really, all along on license renewal, and now we are actually - we have very visible signs of the culture shifting to this long-term thinking on aging management, and we're proud of that.

We have provided training specifically for the implementation of license renewal, to health physics and engineering personnel, and that training is already complete. Chemistry personnel will be completed by the end of this month. Training for mechanical maintenance, electrical maintenance, and work planning will be completed by the end of the year.

Then there are two other groups that we want to provide training to on a face-to-face basis. All these groups, it's been an actual presentation to them, rather than read and sign. The other two groups that we have yet to get to are operations and I&C maintenance.

Operations training was full for this year, so we are in the first quarter of next year for operations. They offered to have us provide a read and sign. We said we felt that it was more important that we have a face-to-face presentation with them, let them ask all the questions they need, so we can get that feeling of really internalizing aging management, long-term aging management, and license renewal. They agreed to that, so we're going to be completing that training by the first quarter of next year.

Then the final group is I&C maintenance, and that organization only trains twice a year, so we will get it to their Spring training, since they were filled up for the Fall training session. So by the Spring of next year, all affected organizations will have had a face-to-face presentation and an opportunity to ask questions and interact with us.

We also assigned a License Renewal Program Owner. In fact, the program owner is here with us today, that's Tom Hendy. The program owner duties are to provide assistance and advice to the engineering organization, especially in the area of when they have questions about license renewal or long-term aging management, or they’re thinking about making design changes and so forth, there's a person they can go to and ask questions, who is an expert in this area.

Also, this program owner will be monitoring the daily CRs and ensuring that aging effects that require management are being identified and addressed. He will ensure that all commitments are scheduled and completed as required, ensure that the proper training of all personnel continues to take place as necessary. He will ensure that all tasks supporting the commitments are entered into our Action Item Tracking and Trending System. This is where we make assignments to all organizations across the site.

And other miscellaneous tasks. So this

person basically owns license renewal going forward, as would our program owner for Appendix R or station blackout or any of the other programs.

We also have already marked up many of our procedures. Our design control manual, which controls how we do all of our design changes across the plant, has been marked up and through the committee - the Design Control Manual Committee - and is waiting on our drawings, which are being converted right now and ready to get - being made ready to go into the system.

When the drawings are ready, the design control manual and the drawings will become effective this Fall - no matter when we get our renewed operating license, they'll become effective this Fall, so that there's no gap between when license renewal had all these documents current and when the plant takes them over and continues them on a going forward basis.

In addition, we are in the process of marking up any of the program documents that could interface with license renewal in any way, and that will be followed by markups of individual procedures for individual tiny steps that support any of the commitments or any of the program changes that we've made for license renewal.

Those final changes will be completed within a two-year cycle. They're, in many cases, very minor, but we will use the biannual review process or procedure process to capture all the remaining changes.

So the overall big administrative changes are taking place now. The others that could interface with license renewal will be done by six months after the time we receive our renewed operating license, but I expect much sooner, since we're making very good progress. Then the remainder will be completed within two years.

We have also done something that we're not - we don't know if anyone else has done this yet, but we've done a license renewal implementation impact assessment.

What we did was we identified every little task that we would need to do going forward for license renewal to ensure that aging management would be managed effectively, and that includes procedure changes, work orders; that would be written work orders that needed to be scheduled, program changes, all items of - inspections, new inspections, anything like that.

We went to each individual department that we would expect to be doing those tasks and we asked them for a resource impact assessment: what would the cost be, what would the man hours be, would you be contracting this, would you be doing this yourself?

That had kind of a dual effect. One, it got them thinking about the fact that they'll have to schedule these activities and that there's cost moving forward, and therefore began true internalization of the impact of license renewal going forward. Then the secondary effect it had was giving us a price tag for what it's going to be costing the plant to go forward into the period of extended operation.

That was all loaded into a database and that's being rolled up. We have not quite completed it. We have one more group to get to.

But at this point in time, it looks like the cost of implementing license renewal - and this does not include replacing the pressurizer, because that was going to be done already, but this is just for what license renewal added to the plant, going into the period of extended operation - is somewhere between $10 million and $15 million, so let's say $12 million or so.

So if you tack that on top of a price tag to do license renewal, which is somewhere between

$15 million and $20 million - say $18 million - if you look at a $30 million price tag for license renewal, that includes going into and completely through the period of extended operation, that's still pretty good bang for the buck.

VICE CHAIRMAN SHACK: What's your pressurizer replacement cost?

MR. WATSON: I don't know. Does anybody from the Millstone team know what the cost of the pressurizer replacement is going to be?

MALE SPEAKER: I've heard the number around $40 million.

MR. WATSON: Okay. But again, that would --

MEMBER POWERS: Let me make sure I understand correctly. You're saying for 20 years of renewed operation, you're going to have a delta cost of $15 million?

MR. WATSON: Somewhere around that, between $10 million and $15 million.

MEMBER POWERS: How many people exactly?

MR. WATSON: Well, it's one person as a program owner. The rest of it are all the inspections that need to take place, the work orders that need to be written, all that.

MEMBER POWERS: Yes, I understand, but roughly how many man-years of --

MR. WATSON: Let's see. I didn't do it in man-years, but it's a little over - like 3,050 man-weeks of time.

MEMBER POWERS: 30 or 50 man-weeks? So all these inspections and programs are going to be done in three-quarters of a man-year?

MR. WATSON: Man-weeks, not man-hours. Man-weeks.

MEMBER POWERS: 30 to 40 man-weeks is --

MR. WATSON: Three thousand and --

MEMBER POWERS: Roughly three-quarters of a man-year?

MR. WATSON: I'm not understanding. Thirty - 3,050 man-weeks.

MEMBER POWERS: Oh, 3,050 man-weeks?

MR. WATSON: Yes. Yes.

MEMBER POWERS: And that's spread over - that's the 20-year --

MR. WATSON: Yes, that's spread over the 20 years. That's correct.

Individual tasks for each commitment will be loaded into the Action Item Tracking and Trending System. So we have the commitments in the FSAR, we know what they are, we know what their status is, and - however, there are all individual little tasks that support those commitments and each and every one of those - which really is what I kind of talked about when we did our resource assessment, that I identified those tasks for us - they'll be loaded into our Action Item Tracking and Trending System, which is where we make the assignments.

Out of that will come our actual specific schedule for each one of those tasks. Commitments will be implemented prior to the period of extended operation or sooner. I'd like to stress sooner. I think I've given you good evidence of the fact that we are living it now and we will be completing these commitments as soon as possible.

I would like to say that there are a couple of commitments that we are well aware of you would not want to do right away, unless an opportunistic inspection occurred. That would be like digging up buried piping. We've got the buried piping inspections and that's one that you'd like to hold off closer to the period of extended operation for two reasons.

One, there may be an opportunity to take advantage of a dig that has to take place. Or two, if you do have to do the dig, it's good to get the maximum amount of operating experience before you do your dig.

One side comment on that - doing this kind of baseline inspection was a difficult commitment for me to accept. I have accepted it, but it's a little difficult to accept because when you dig up these pipes, you do disturb them. The fact that you haven't had to dig them up is a pretty good indication they are coded properly and were set properly in the ground, and so we prefer to wait closer to the period of extended operation before we have to dig these up and see what they look like.

Finally, as I mentioned before, the FSAR will be updated upon satisfactory completion of a license renewal commitment, so these commitments are going to be treated as obligations under the current operating license. The only time we will not be requesting NRC approval to make a change to those commitments is just to change the status from working to complete. That we will do on our own.

That concludes my presentation. Questions?

MEMBER SIEBER: After the subcommittee meeting, we had a number of questions, which we stated at the time and we also stated that we expected a further explanation or discussion or answer at this full committee meeting. One of those questions that was asked by Mr. Bardin had to do with the fact that there was not an aging management program for protective coatings inside containment?

MR. WATSON: That's correct. We --

MEMBER SIEBER: It seems to me that protective coatings, they have to stay in place during a LOCA event. Otherwise, they will travel to the sump and it would appear, based on current research, that there is some possibility that a coating can undergo a chemical reaction, should it not adhere to the surface to which it was applied during this high-energy kind of event. Have you considered that further?

MR. WATSON: Yes, we did. We happened to be - GSI-191 came out about the time that we were determining what we were going to do with this problem and about - at least, we became most aware of it about the time of the subcommittee meeting.

We had, as you know, at the subcommittee meeting, we stated that we - for all coatings, the way we treated them is that we did not credit them for protecting the underlying material. And then, of course, the question was, well, we know that, but for containment, the concern is that the coating itself may come off and clog the sump, which is the subject of GSI-191. And --

MEMBER SIEBER: Well, that's one of the issues that appears to be evolving in GSI-191.

MR. WATSON: Right, and --

MEMBER SIEBER: It's not the only one.

MR. WATSON: Okay. All right, I understand. Thank you. But as far as this particular question, it is being answered for us by our response to GSI-191. We are looking into design changes to address full coating failure in the containment and preventing clogging in the containment sump and giving us acceptable results.

In that case, we would not need any kind of aging management program at all. Specifically, it would not require an aging management program. However, we would probably still maintain a program that we do have at the plant that does inspect the coating and does repair the coating.

Also, we weren't sure what kind of aging management program we would develop for addressing this issue, since it was being addressed by us under the GSI-191.

So we really did take a wait-and-see

approach on that, and the reason we did that is, we know that our response to GSI-191 will either say that we don't need an aging management program or that we do. If we do, we will have to develop that in current licensing basis space, and that program will carry forward into the period of extended operation and become a license renewal related program.

We didn't want to really jump the gun, and plus, there were a lot of questions on how you go about doing that that were already being addressed in this other area.

MEMBER SIEBER: Well, I agree with you that it is a current issue and not a license renewal issue. On that basis, though, it's a personal concern of mine, and I think that we are also responsible for reviewing GSI-191 and all of the associated documents, including your response.

Since the question come up here with regard to Millstone, I think that I will commit myself to looking at your response with respect to the adherence of coatings and the potential for them to come off and potentially, again, cause interference with the sump. I think that that would be a reasonable resolution of the question that was asked.

There were also some statements during

that meeting where we requested that you give the recent operating history for the units. You have done that in your presentation, which I thought satisfactorily addressed that point. So I may ask now, do any of the other members have any questions for the applicant, Dominion?

MEMBER RANSOM: Are any in situ methods used for examining buried piping or other buried components?

MR. WATSON: I'll ask the team that. Gary, do you want to address that question?

MR. KOMOSKY: Sorry, I don't want to bump my head. My name's Gary Komosky. Yes, we do crawler inspections in our service water systems for our underground buried pipe. We have access points in the system and every refueling outage, we inspect one header, so we will send a crawler in the pipe and inspect a hundred percent of the buried pipe.

MEMBER RANSOM: How is that done? A person will actually enter the --

MR. KOMOSKY: No, it's a mechanical machine. It's a crawler with a camera on it. I mean, we have sent people in the pipe, but we try to avoid that, from a safety standpoint.

MEMBER SIEBER: Actually, Dominion's had

a lot of experience at Surry dealing with service water pipes and repairs.

Any further questions? If not, thank you very much and I would turn to the staff. We are running short on time.

MR. EADS: What I've asked Tanny to pass out is something I'm going to cover in the second half of my presentation. In response to subcommittee questions, I've brought inspection findings over the past period.

Good morning, my name is Johnny Eads. I'm the senior project manager for license renewal for the Millstone application. I've been on the project since it first began and I'm happy to have brought it forward this far. I appreciate the staff members who are in the audience, not only to help me answer questions, but who actually performed the detail - hard work - comprehensive review of this application over the last 18 months or so.

Again, the SER is really their product. I pulled it together for them, but it's their review, and I appreciate their help. I'm going to move quickly through the slides. If you wish to stop me, please do so, but I'm going to try to keep you finished by 9:30.

Most of this was covered. The two license renewal applications were submitted by letter dated January 20th. You see the OL expiration dates. We've already talked about the differences between Unit 2 and Unit 3. I should say that having two different units, two different vendors, did complicate the review, but the necessary resources from the staff were brought to bear and I believe the review was completed in a satisfactory manner in the time - I should say, on the original schedule dates.

The NRC review process was a standard process that we have used on the three pilot plants. It was a scoping and screening methodology audit. There were also consistency with GALL audits, both for aging management programs and for aging management reviews. We also had a series of regional inspections. That was a scoping and screening inspection, as well as an aging management program inspection.

Quickly, on this slide, it just documents the dates of those audits. You'll see we began in late March and those audits continued through 2004, through the month of October. I'm not going to go over each of those dates. But as you can see, there was a significant amount of time spent on site, reviewing on-site backup material, as well as walking down the facility.

This was not a paper review of the application completed here in headquarters alone. It was an in-depth review, both on site and in headquarters.

The SER, with open items, we issued on February 24th of this year. That SER had six open items identified, as well as six confirmatory items and three license conditions. I would like to spend a little bit of time talking about each of the open items and the resolution of those open items.

On August 1st of this year, we did issue the final SER with all open and confirmatory items closed. We are waiting for an ACRS letter, of course, prior to publishing the official NUREG.

Quickly, each of the SER open items - these are the six. The first one related to, as Frank mentioned, (a)(2) criteria. This is non-safety-related equipment with the potential for affecting safety-related.

I think it's well-documented in the SER that the application proposed an initial (a)(2) methodology, which the staff challenged. As a result of those staff challenges, that methodology was adjusted, additional justification was submitted, and it resulted in eight additional systems being added to one unit and additional components being added to both units within the scope of license renewal. Those impacts were reviewed by the staff, evaluated, found acceptable, and this open item was closed.

There was an open item dealing with the scoping of the reactor vessel flange leak detection system line --

VICE CHAIRMAN SHACK: Just --

MR. EADS: Yes?

VICE CHAIRMAN SHACK: Were these (a)(2) issues that really were independent of past precedent? We've heard that Millstone paid a great deal of attention to past precedent. (a)(2) has been a problem before. Was there some nuance here that was different?

MR. EADS: Let me mention two items. First, I have to mention that the (a)(2) guidance, although it has been a portion of the review, I believe that with each review, it becomes more and more clear.

I think with the Millstone case, you heard Frank mention their assistance in developing additional background on bounding criteria for (a)(2), which I think lays out clearly for all applications going forward what the expectation is. But that was an evolving process, so for the first, I would have to say that there were some adjustments made to the guidance.

The second, though, there were some words - as an example, including base-mounted equipment within the scope of license renewal. You'll have a non-safety run of piping, which terminates in, let's say, a heat exchanger, a large base-mounted piece of equipment. The application came into us and said that they committed to include within the scope of license renewal all of the material up to that fixed piece of equipment.

Unfortunately, that is short of the staff's expectation, which is up to and including that fixed piece of equipment. So we insisted that the fixed pieces of equipment also be included within the scope of license renewal, and they agreed to that and made that change. So there's really two pieces to that.

The second open item I started to mention was the reactor vessel flange leak detection line. Again, that's a small line - the agency, when it originally - or the applicant, when they initially reviewed it, took credit for a 3/16 inch diameter orifice within that line, which proves that that line, even if it were to fail, would not have the potential for affecting safety-related components.

The staff reviewed that and found that it did vary from our guidance. We believe that a system, even with the existence of an orifice, should be properly managed, age managed, the aging effects evaluated, and appropriate actions taken through the life of the plant for that line.

Upon subsequent review, the applicant agreed with the staff's findings and incorporated it. I would mention that it is made of stainless steel, same materials and environments as other piping within the containment area, and so it was a minimal impact on them to add that item to the scope.

The next two items are related to bolting. The first was loss of preload for non-class 1 bolting. Those of you who are aware, we do include loss of preload - or the applicant did include loss of preload for class 1 bolting, but an issue came up on non-class 1 bolting.

The loss of preload, the primary concern there is stress relaxation. Applicant argued that because of the low temperatures in these particular non-class 1 applications, that they did not see stress relaxation as an area of concern.

Staff pointed out that the GALL report clearly identifies that in addition to stress relaxation, there is the possibility of other mechanisms, which might cause loss of preload. Vibration being the best example - it could just shake loose.

So after pointing that out to them, they have agreed and did subsequently include loss of preload as an aging effect for all non-class 1 bolting.

The second bolting item dealt with references to EPRI Good Bolting Practices. Again, we look to the GALL report. The GALL provides an EPRI document as a reference for good bolting practices and our expectations would be that applicants would commit to that EPRI guide.

Dominion, in its application, committed to - I'll call it a previous version, but - a previous generation of EPRI Good Bolting Practices, and we asked them to demonstrate to us that there was indeed good coverage for aging management of those bolted connections for the Millstone plant.

And they did. They submitted us a good

comparison document that compared the old bolting practices document to the new one. There's a large amount of similarity there, many of the items being duplicative, and certainly, within the area for Millstone and aging, it was covered. So we closed that issue. There was an issue dealing with reactor coolant pump casing, Code Case N-481 --

VICE CHAIRMAN SHACK: I just - why wouldn't they update to the current guidance? Is it just the --

MR. EADS: I think it's just --

VICE CHAIRMAN SHACK: The expense of updating procedures and such?

MR. EADS: I think that the EPRI document that they committed to was equally as valid as the document referenced in GALL. They did have that document imbedded within their procedures, had been trained to that.

This is not something they were adding for license renewal. I'm sure if they were adding it for license renewal, perhaps, they could have looked for a later version, but this is an existing program, which the plant was used to using.

The fifth open item was on the Unit 2 Reactor Coolant Pump Code Case N-481. That is a cast material - casing. There were questions raised about the analysis that had been submitted from a vendor. We reviewed that analysis. We had some questions on it related to material properties.

I don't know if you're familiar, but there was a letter in the Year 2000 transmitting to utilities latest material properties - fracture mechanics type properties for this material and we needed to verify that, indeed, they had adequately done the analysis.

We ended up doing our own analysis. If you read the SER, you'll see that the applicant's testament was 103 years endpoint and our conclusion was that it was closer to 87. In both cases, we're in excess of 60, so that item was closed, by the leak-before-break analysis.

Not clear within the application what was the scope of that analysis, what components were included. We asked them to verify that. They did so in a letter. We reviewed it and found it to be acceptable.

Those were the six open issues that we looked at and addressed. Let me talk about an issue from the subcommittee. We sat in this room and we talked about fire protection systems. No engaging effects required for management for halon and CO_2, carbon dioxide systems, and we said that based - that the application had come in and based on their own operating experience, that indicated that they saw no aging effects within those gaseous systems.

A question was asked in this room, if it's okay on Millstone, why isn't it okay for everybody? Are you going to update the GALL? Coming out of this meeting, we had actions taken. GALL was reviewed for update.

Through that process, we determined that we did not want to update GALL - that even though the operating experience at Millstone over the last 20 and 30 years did not indicate any activity, taken in a broader look, GALL addresses industry experience across the industry at many plants, and so we did not feel that the weighing of the Millstone experience overrode the industry operating experience in this area.

In fact, our fire protection group was aware of aging issues associated with the piping, and through their insistence, we did revise the SER in this area, even though it wasn't an open item. The applicant has now committee to including aging effects for those fire suppression systems - halon, CO2.

Again, I would mention that the inspections of those items are things that are already required by their existing commitments to current plant operations. Current commitments to the code establishing periodicity for walk-downs of those systems. So although they committed to add them for us, the net impact was probably minimal, because they were already doing those items.

My next four slides, just briefly, are the update to the performance indicators for the plants, since our meeting with the subcommittee. They remain the same, though. They are all green on performance indicators for Unit 2 and Unit 3.

There are some slight changes to inspection findings. All inspection findings in the current performance through the second quarter of 2005 remain green. You'll see four green panels on that slide and then when we get to Unit 3, there are five green panels on that slide.

I did provide, for those who are interested, a more detailed look at each one of those findings, which you may look at at your own leisure, but I want to point out, too, I just will tell you that on Millstone Unit 2, there are five inspection findings that are green.

On Millstone Unit 3, there are 13 green inspection findings for the period. None of the ones I identified on Unit 2 seemed to have a tie to license renewal, but in Unit 3, I identified two of them that had a slight license renewal tie. So the first three pages are Unit 2, I would skip those.

On the first page for Unit 3, there at the bottom, you'll see one that does sound similar to what aging management programs would be concerned about, and it's the less than adequate corrective actions for the potential RCS pressure-bound degradation due to boric acid corrosion, a topic certainly that staff has focused on recently and continues to focus on.

That particular item dealt with a small leak within containment on one component and the plant's failure to do complete walkdowns and identify other leaking components in the area. Also, the one example that was identified, the plant's failure to look at perhaps the extent of spray or other conditions on other equipment.

Those are the findings that were found by the inspection staff. You'll notice that this item is a non-cited violation and there's two reasons why that is. One, that means that the plant has now taken ownership of this issue, has identified it in their corrective action program, and is required to come up with corrective actions to preclude recurrence on this particular issue.

So the staff has some confidence in the corrective action program in Millstone. This item has been added into their - but it was obvious from this violation that additional actions needed to be taken. So I would point --

MEMBER POWERS: Let me ask - you bring up one that you thought was related to license renewal, but I look at the others and I see failure to implement, failure to adequately conduct. In the license renewal, we're adding a large number of new programs that have to be carried out on a timely basis, on a regular basis. Don't those have some impact?

MR. EADS: Yes, they would, from a staff standpoint inspections - through inspection efforts in the region will continue throughout the period of extended operation.

If this license renewal is granted, inspections similar to this one will continue to be conducted because we, like you, believe that implementation of those programs is important and they continue to implement them as necessary in order to maintain the licensing basis.

So, yes, we have every expectation that inspections from the region will continue. We'll continue to look at these programs. We'll highlight these areas. You're right, it does give indication that the current process is - needs to be --

MEMBER POWERS: What are they planning to do to say - they're getting a heavier load here. They've got to do more. They're having troubles doing what they're doing now. What are they going to do to fix that?

MR. EADS: Let me let the applicant speak for itself in that area. Bill, if you would like to address that.

MR. WATSON: Yes. This is Bill Watson. I think it needs to be kept in perspective that these are individual discoveries on a - even for instance, the one that Johnny pointed out, it's one discovery on a program that has very, very good success overall.

We've had a number of inspections, a number of evaluations, Nuclear Oversite audits. Daily, we get CRs coming in, where we do have boric acid leakage. The program is working very well. This is an error and this was missed and you're going to find through inspections, over the years, and this one included, you will find errors that occur --

MEMBER POWERS: I think you --

MR. EADS: But that doesn't mean the program itself is not working and is not adequately addressed.

MEMBER POWERS: I think you lost track of where I was going there. I'm looking at all the others, where I see failure to implement, failure to properly - etc., etc., etc.

And I'm asking you now, you've got a heavier load. Okay? You obviously have an occasional -- it's not a huge list, but it's a list.

The fact that there are any at all says, okay, now you're going to have to do more. You're obviously - up to what you can do - what are you going to change in order to carry out these additional activities to the level of precision the staff is expecting, which is not to have any of these? Am I correct?

MR. EADS: That would be the staff's expectation.

MEMBER POWERS: That would be the staff's expectation.

MR. WATSON: I would say that the corrective action program, with this particular inspection and all other inspections, when we find that we have areas to look into further, such that has been identified by this inspection, that goes into our corrective action program and we asked ourselves the same question.

I don't have an answer to you exactly how we are addressing this immediately, but I would say that we have - the NRC has determined us to have an effective corrective actions program and these are isolated cases where it indicates that we have made an error.

The new programs - I'd like to address that in a couple of different ways. A lot of the programs that we credit for license renewal, we're doing right now, so a lot of those activities are already being done and being done satisfactorily.

There is an additional workload being placed on the plant, and I agree with you, and we will have to ensure that those programs are adequately implemented so that we don't have these errors. But I don't think we'll ever have a hundred percent error-free operations.

MEMBER POWERS: We wouldn't expect you to, but we sure hope you do. I bet you do, too.

MR. EADS: I would leave the record

incomplete if I didn't point out one additional example, and I do want to do that. A couple more pages in, you will see an item - it's related to a divider plate - failure to properly evaluate and correct a degraded condition associated with a divider plate for all three CCW heat exchangers.

Now, in both of these two cases, I want to point out that these findings are green and in this particular case, it was dealt with as a qualification issue and said that the degradation that was actually cited would not lead to loss of function. So for completeness, I would like to mention that other item, as well.

With that, I'd like to move to the staff's conclusions. The staff has concluded that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the current licensing basis and the changes made for the Millstone current licensing basis in order to comply with 10 C.F.R. 54.29, or in accordance with the Act and the Committee's regulations.

That's the conclusion of the safety evaluation report.

MEMBER SIEBER: Okay, thank you. Any

additional questions to the Committee members?

MEMBER DENNING: Yes, I have a question about staffing levels and whether there's anything that's being done to staffing levels in this period of time - and I think it's more a question for the applicant than it is for the staff - is there any increased staffing that's being done that would help with the kind of issue that Dr. Powers has talked about. I realize there's a program owner, but I don't know whether that program owner really gets into these types of issues.

MR. WATSON: Well, the program owner is, as I stated in my presentation - this is Bill Watson again - the program owner is expected to review all condition reports for aging management issues, so the program owner certainly would get involved if he saw any kind of a trend - as well as our corrective actions program, the way it's designed, we'd be looking for trends.

But as far as additional staffing is concerned, overall - of course, we have the program owner. That was an addition to our staff. And we will - for certain tasks, we will be contracting for inspections and so forth to take place that were especially designed for license renewal.

But we - to answer this specific question, I don't believe that we have any plans, at this point, to add corrective actions staff people or whatever to look at this. Again, I think we just - we have to evaluate our programs on a constant basis and ensure that we are not making these errors and if they come up, we have to address them. I guess that's the best I can say.

MEMBER DENNING: I realize that staffing levels are a huge economic issue and that there are always pressures to decrease staffing levels. Could you give us some indication, within the area of corrective actions, what is the level of people that are dedicated to that type of activity, how has that changed in the past, and how do you - but based upon what you have said, you don't anticipate any increase to address additional issues associated with these new commitments?

MR. WATSON: That is correct. I'm not sure of the number of staff we have in the corrective actions department. There are various disciplines throughout that department. But I would say that if we were to have indications through our own Nuclear Oversite inspections or NRC inspections that our corrective actions program was not working properly or had problems, I would feel pretty confident saying that we would get additional help, whether that be contracted help or help from our other sites, to assist us in the corrective actions area, because we --

MEMBER DENNING: That does sound like a rather reactive, rather than proactive, position.

MR. WATSON: I understand. I say it that way because our monitoring indicates that we're doing well in this area right now and we are constantly monitoring. Yes, there are findings of errors, but we are doing well overall. If we feel that there are too many of these errors, we would take action to address that. That's what the program calls for and that's what we would do.

MEMBER SIEBER: I think maybe I could add a little bit to that. Corrective action systems actually generate additional work for procedures staff, operating staff, training department, maintenance staff, and so forth, and management typically will look at backlogs as a way to judge the extent to which the current staff is performing with regard to dealing with all of the corrective action items that need to be done.

When that backlog increases, it generally will extend outages or require additional people to do them, and I think that's an ongoing area, where the applicant's - management people will continue to scrutinize and manage your backlog, as well as the staff and the resident inspectors. They also look at backlogs and whether corrective actions are happening or not. So it's something that can be measured and it's something that is one of the basic tools that the licensing management uses.

Are there any other questions?

MEMBER POWERS: Well, let's follow up on what you're saying. What are the oldest items on their corrective action list and how old are they?

MEMBER SIEBER: I don't know that perhaps the licensee could answer --

MEMBER POWERS: I'll ask the team.

MEMBER SIEBER: The typical age of your - and you'll have several lists, one that is non-outage stuff and the other one is outage area.

MR. WATSON: Right. We do have to be careful on that because there are priorities set on each corrective action. Some are 180 days, some are 120 days, some you don't have, because they are a question that got answered or a broke/fix or a nice idea that came from a benchmarking trick.

It's still called a corrective action, whether we plan to take it or not, and those don't have a specific timeframe that's required, except that as it was pointed out. If it ends up piling up and building a backlog, you would have to work that backlog down, so I can't give you an exact figure for the average age, but that is looked at by the inspectors, the NRC inspectors, when they come in and our Nuclear Oversite Department.

If there was an issue in that area, I would have expected that to have been identified.

MEMBER SIEBER: With that, I would also just like to add one thing at this time, which is my thanks, my personal thanks, to the staff because in addition to the documents that we were given, I also asked for drawings and other documents, which were promptly provided and any help that I needed in the conduct of my review was certainly provided.

I appreciate the cooperation of the staff in that regard and it really helped me do my job. I think at this time, each of you has received --

MR. EADS: There's Nancy Burton on - oh, I'm sorry.

MEMBER SIEBER: Oh. Each of you has received a letter from Ms. Nancy Burton, Connecticut

Coalition Against Millstone. She has asked for a few minutes this morning to address the full Committee with regard to the viewpoint of her organization related to license renewal. Are you there, Ms. Burton?

MS. BURTON: Yes, I am, indeed.

MEMBER SIEBER: Okay. It's your turn.

MS. BURTON: All right. Well, I thank you very much and I especially thank Mr. Tanny Santos for making it possible for me to participate from a distance in these proceedings today. I am looking forward to your comments to my letter that I e-mailed and faxed to you yesterday, but I also at this time have a few additional comments.

But I'd like to begin with a question, and that is, I wonder if you have had any written contact from the State of Connecticut, the Governor's Office, or any other public agency within the state with regard to the State of Connecticut's input on the Millstone relicensing application and in particular, the final SER?

MR. SANTOS: No, we have received nothing like that, Nancy.

MS. BURTON: Thank you. We have invited the Governor to appoint a task force to assist in evaluating this highly technical information and that request has been presented to the Governor and we are looking forward to positive action shortly.

I wanted to be sure that everyone in attendance knows a little bit more about the history of Millstone that hasn't been highlighted in the presentation, either by Dominion or the staff, and that is that Millstone, of course, has the unique position of having lost two spent fuel rods and after a conscientious search, in their words, haven't been able yet to find those spent fuel rods.

That represents really an ultimate betrayal of the public trust in this operation. Millstone has, over the years, had some of the highest releases of radiation to the environment. Millstone has been responsible largely for the virtual extinction of indigenous fish docks.

There is a phenomenon in this community of very high cancer incidents and we have had the benefit of experts who have assisted us in trying to understand this issue and they have been making links between the Millstone emissions and cancers.

We, last April, made it down to our subcommittee meeting. There was information about young Zachary Hartley, born with cancer in his face after his mother swam in the so-called “nuclear mixing zone” at a public beach spot, Niantic Bay, near Millstone. Dr. Helen Caldicott, who is a world-renowned pediatrician devoted to the understanding of the health effects of low-level ionizing radiation, after she reviewed Zachary's medical records and Millstone’s emission effluent release reports concluded a high probability of a link between the Millstone emissions and Zachary's mother's exposure to the radionuclides and the toxic materials leading to Zachary's condition.

I haven't seen, in the SER or any of the materials submitted or considered, that the link to how Millstone intends to become responsible for the millions of dollars in health costs associated with the health effects of this operation.

In Zachary’s case alone, there have been millions of dollars expended in life savings, miraculous surgery and it's that basic factor that should be considered, just as the NRC is being asked to consider rejecting most of the SAMAs that were conceived during this process based on a cost-benefit analysis, with the public suffering from a lack of the proper and due consideration.

In our review of both the SER and the

environmental impact statement, we have tests to conclude that this process has been near farcical and for those facts that the incident was Class 2 emergency, which occurred on April 17th of this year, while Millstone was under the spotlight, one would think, during the NRC's review of the relicensing application.

That really illustrates perhaps better than most of the other failures at Millstone why this plant should be closed, shut down, and not open to continue in operations.

We haven't heard any feedback from the reports that we presented to the inspection findings of the most recent period of time, other than a very brief mention by Mr. Eads a moment ago. The most recent inspection reports have found a shocking degrading of conditions and many times, the poor training to the extent that inspectors even concluded that operators were incompetent to operate the plant.

When the tin whisper caused the short that brought Unit 3 to a sudden shutdown on April 17th, if, in fact, that was the culprit, there was pandemonium in the control room and the three gentlemen there did not know what the heck was going on and they were fed misinformation from their instrument panels and for a period of at least a day, the community lived in abject terror, watching steam cascading out of Unit 3, which usually doesn't manifest that kind of phenomenon.

We received a call from Providence, Rhode Island, from panicked individuals who had seen the steam on television and wondered if they should evacuate. Was this a Three Mile Island - what was going on?

And I wanted to just emphasize a little bit more about how that incident, and how it was handled by the NRC, gives cause for us to have pause to reconsider the input from Dominion on this relicensing application.

During the duration of two weeks, where Unit 3 continued to be shut down, after that initial scram, day after day after day, Dominion was releasing press releases saying that the public was not at risk, there were no unusual radiation releases, and other information that later proved to be false and the NRC, to its great discredit, reported to the news media information that simply parroted what was coming out of Dominion.

It was only after political pressure was brought to bear to the situation that the NRC started to disclose the unusual radiation releases that did contaminate the environment and did expose the population to heightened risks of harm, as we know, from the BTIR-7 radiation study.

I want to also call attention to the fact that Millstone was on the watch list, 1996. It was shut down because of a scandal and the scandal was that conscientious workers were being fired for trying to run the plant safely and finally, they broke the news to the news media and that entire station was shut down, an unprecedented shutdown for six years.

It was allowed to come back because we have had a compromised political system in Connecticut. Our Government was John G. Rowland. He is now serving time in a Federal penitentiary for corruption. During the late 1990s, the operators of Millstone pleaded guilty to committing Federal felonies involving violations of their Clean Water Act permit, discharging known carcinogens to the water that wash onto our public beaches in Connecticut.

We have had quite enough of this harm to the community and we ask that you postpone final decision-making on this application to enable the State of Connecticut - a little bit late, a little tardy, but not too late - to have input here; to rise to the occasion and give the application the critique that an independent panel of specialists would bring to the task.

I would like to point out the comment that I heard this morning, that Dominion is considering an uprating or an upgrade and that is a fact that should be considered most definitely in this review of the relicensing application.

The NRC accepted at face value Dominion's statements that it's planning no major refurbishments. We know that is not true. Probably they are delaying that because of the difficulties experienced at Vermont Yankee recently, but the fact is, that is in the works and we've now heard that from Dominion this morning.

This application should be put on hold until there is a consideration of that kind of refurbishment, in addition to the necessary refurbishment to convert the station to a closed cooling system, as I mentioned in the letter.

I think I've covered many of my points, but principally, what is most troubling about the review is that it is turning a blind eye to the cascading degrading conditions that are obviously economically driven at Dominion in a deregulated environment so that there is mismanagement of manpower and a continuing granting of waivers for the safety standards or lack of safety standards so that the public is more at risk today from Millstone operations than it was when it was initially licensed.

This is an unacceptable condition. Dominion is dictating to the U.S. Department of Homeland Security - in effect, vetoing the Federal Government, directing it to install taxpayers paid for barriers to protect the station against a terrorist attack, as all Naval bases around the U.S. are protected, witness the sub base nearby on the Thames River in Groton.

This situation is not acceptable to the community and we ask that you return to your task of the business of the NRC permitting Unit 3 to restart after tin whiskers were identified in circuit boards that were not ordered to be replaced. That is unacceptable. That is not addressed in this SER. The SER review has been grossly inadequate and defective.

I will close with this comment. I happen to be on the phone today in a remote location in the wilds of New Hampshire, where I'm in a home once occupied by Vannevar Bush, a member of the original Atomic Energy Commission, and he abandoned this site following a very devastating hurricane, which brings to mind what's going on down in Louisiana with the Waterford plant having a so-called robust safety system and I'm not sure if that plant is operating again, but that plant had to shut down because of lost off-site power and told that community that was already brought to the brink of catastrophe.

This is unacceptable and this community should not have to endure continued operations of Millstone. I appreciate the opportunity to provide these comments and I look forward to responses to the issues that we have brought to you.

MEMBER SIEBER: Okay, thank you for your comments. We're a little bit late at this point, so I'd like to turn it back to you, Mr. Chairman.

VICE CHAIRMAN SHACK: Thanks again to all the presenters this morning. We are going to go into a recess now. We'll come back at 10:15.

(Whereupon, the above-entitled matter went off the record at 9:58 a.m. and resumed at 10:16 a.m.)

VICE CHAIRMAN SHACK: We'll come back into session now. Now we're going to take up the interim review of the Exelon/Clinton Early Site Permit Application, and Dr. Powers will lead us through this issue.

MEMBER POWERS: This is the third of the early site permits that we have examined. Previously, we examined North Anna and Grand Gulf, with previous applications, weather and transportation accidents, where the foci of our immediate interest - seismic issues were a little more ancillary.

We've certainly, in the case of Grand Gulf, looked at the New Madrid seismic zone. The case of Clinton is a bit different. It's not immune to severe weather hazards, but it doesn't have the hurricane problems that our other sites had. It does have interesting issues connected with seismic.

It is located in a site that is affected by the New Madrid, the Wabash Valley, and the Springfield earthquakes, so a lot of the attention in this particular early site permit is indeed on the seismic issues.

The licensee has come forward with an approach to the seismic issues that's different than what we've seen in the past. It's significant because there are certainly indications that we're going to see this kind of a reproach. It's based on an industrial standard in other contexts, so it's useful to us to try to gain some understanding of it in this particular application, even though this is about an interim review of this particular early site permit.

What we did in our subcommittee is we divided the subcommittee down into two parts. The first part addressed everything except the seismic issue, and then the afternoon, we devoted to the seismic issue. I think it was a useful indoctrination on both aspects of it.

There are issues of interest in the non-seismic area, particularly in the area of hydrology, that we did not explore with a great deal of thoroughness in the subcommittee meeting, but it's explored fairly thoroughly in the written material.

What I have asked the various speakers to do, I've asked the licensee to particularly focus in their presentation on the description of the plant and the context of the early site permit. As you're well aware, this site permit, like the others, is on a site where there's an existing nuclear power plant.

I've asked the staff, in their presentation, to focus particularly on where they had open items and what the schedules are. So with that bit of a background and introduction, I'll turn it to the licensee.

MS. KRAY: Thank you, yes. Thank you, Dr. Powers. My name is Marilyn Kray. I'm the Vice

President of Project Development for Exelon Nuclear. We greatly appreciate the opportunity to be with you this morning.

I wanted to introduce just the speakers for this morning's session. To my far right is Eddie Grant, who is the Exelon lead for the site safety analysis report.

To my immediate right is Dr. Carl Stepp. He is the Chairman of the Seismic Board of Review. That was a group of outside industry experts in the seismic area that Exelon convened in order to provide us guidance and oversight on the seismic activities that were being undertaken as part of our ESP application.

As expected, much of our discussion this morning will focus on the seismic issues, and I wanted to preface this discussion with the acknowledgement of the generic nature of the issue. Exelon has become somewhat of a reluctant champion of this issue. I say reluctant because when we embarked on our early site permit project, we did not hope to blaze any new trails in this area.

However, as we proceeded with the seismic characterization of the Clinton site, it became overwhelmingly apparent to us that there were enhancements needed in the regulatory guidance. We did not work in a vacuum regarding this. We conferred with the other two ESP applicants and also, canvassed the rest of the operating industry.

That has resulted in the formation of a Seismic Issues Task Force under the heading of the Nuclear Energy Institute, and through NEI, the industry continues to work to provide the staff and the additional analyses to support the position that's being taken by Exelon. Because again, we did not want to promote any change that would not be appropriate for the group of clients as a whole.

Yesterday, we spoke about some of the background as to why we are pursuing an early site permit and the recognition of the precedents that we would be setting, and so although pursuing this has resulted in additional time and additional costs, we recognize that those are more than offset by the value in setting the right precedent for this.

With that, I'll first turn it over to Eddie Grant, who will address some of the site location issues. He will then turn it over to Dr. Stepp. Thank you.

MR. GRANT: Thank you, Marilyn. Again, my name is Eddie Grant. I'm representing Exelon to discuss the early site permit location information and the review of the safety analysis report and emergency planning information.

One quick item I might identify is that we do have a number of folks here with us today. I'm not going to introduce them all, but if questions come up, we have a number of seismic experts. We have individuals who were responsible for the geotechnical areas. We have information in the other sections - related to the other sections of the SSAR, as well.

So we do have quite a bit of support here with us today. We will, as I indicated, cover a little bit about the project team. We'll cover a little bit about the information that is general to early site permits. We'll cover some site information real quickly through the development approach and a few of the geotechnical results.

Yesterday, we gave a bit more detail in all of these topics, but today, it will be more of a summary. Dr. Stepp will cover some information on our seismic analysis demonstration and in particular, the ground motion determination methodology.

Again, the project team was not just an Exelon effort. The major or prime contractor was CH2M Hill. They have large backgrounds there in environmental. They also did the site redress report, geotechnical and emergency planning areas.

They had a number of support team members as well, subcontractors: WorleyParsons, who was responsible for overall preparation of the site safety report; Geomatrix, who was the major contractor in the seismic area.

As Ms. Kray indicated, the Seismic Board of Review provided expert independent review. And of course, there were a number of other contractors involved in the site exploration areas.

On the right side of the screen, we also had Dr. Bob Kennedy, who is with RPK Structural Mechanics Consulting, to help us out in the seismic area and in particular, the areas of the probability concerns.

Others were also in those areas. Sergeant Lundy did a full review of the application before it was submitted, so that we would be certain to cover all that we needed to. And Morgan Lewis provides legal counsel.

As you're all aware, Part 52, Subpart A, covers early site permits. This is a new process and, as Dr. Powers indicated, we're the third one that you've seen.

The ESP application under an early site permit has five parts - or may have five parts. The administrative information that is typical with any application for a license or a permit that identifies the applicant and the background on the applicant.

The site safety analysis report for an early site permit - it's not the full 20 chapters that you normally see for an operating license or a construction permit, but rather, it covers just a couple of areas - the site characteristics, Chapter 2, and some analysis information, some of which is typically spread through Chapters 11 and 15, but it's all gathered together in Chapter 3 for our application.

We also provide emergency planning information. There is required information under 52.17 for the application. We also have included one of the options under 52.17, which I'll get into a little bit further in our emergency planning information discussion.

A full environmental report was provided and also, a site redress plan, which is an option, again, under 52.17, if you want to do limited work authorization type activities prior to actually getting a combined operating license that would allow full construction.

The applicant is Exelon Generation Company, EGC. It is a wholly owned subsidiary of Exelon Corporation. The site location is in central Illinois. The star here on the map is Clinton, Illinois - not exactly the site location. The site is just a little bit to the east of that. We'll get into that further.

Clinton Power Station, it is on Clinton Power Station property, which is owned by AmerGen. AmerGen is an EGC subsidiary, so there are no real concerns there about being able to use the property.

Drawing in a little closer, this map - site region map - shows the 50-mile EPZ, and identifies some of the population centers near the site. As you see here, this is a site - this is at Clinton Lake, which is barely visible in this map. The City of Clinton here. Some of the major centers again are Decatur to the South approximately 20 miles; Champaign/Urbana, a little further away and to the West approximately 40 miles; Normal and Bloomington population center, again, approximately equal distance from Decatur, about 20 - a little over 20 miles to the North; and Springfield, out here on the edge of the 50-mile EPZ, only partially within, so its population center is almost right at the 50 miles; and Peoria population center, who's actually outside the 50 miles, but right on the edge.

We are approximately equal distance between Chicago and St. Louis. Both of those are well beyond the 50-mile range here. The 10-mile EPZ is shown in this particular figure. Again, we can get into some of the closer population centers - also, some of the smaller ones. This is the site location.

This is the City of Clinton here, which shows the increased population density area. This is a population density map. They key over here - and as you can see, most of the area is in this zero to 20 persons per square mile density, in all of this area here.

You do see a couple of small population centers. The closest one is DeWitt. It's in the five-mile range. It has a population of approximately 200 people. We also have - one second, I'm going to have to look. I'd forgotten the name of this smaller town here. Weldon, yes. We have Weldon down here to the Southeast. It's a little further away. The population on it is approximately 450.

Clinton, of course, is the largest of the areas within the 10-mile. It's about seven miles away at the center and it has a population of approximately 7,500. Three is a small town here as well, Wapella, seven to eight miles away, and it has a population of 650.

Within the 10-mile range is a total population of approximately 12,000 people. That includes both permanent and seasonal, transient-type population. The population projection for this area is no significant change over the 60-year potential life of both the early site permit, which is 20 years, and then the 40-year life of any plant that might be built.

This is drawing in a little closer. Here we show the lake. That is Clinton Lake. This lake was a dam - I'm sorry, two creeks. Here, this is Salt Creek and the north fork of Salt Creek. Here, at the confluence, there was a dam built at the time that Clinton Power Station was built in order to provide cooling for Clinton Power Station. Clinton Power Station was originally intended to be two units. One of those was cancelled after construction had barely begun. We'll see another closer picture to show a little bit of that soon.

So there is plenty of cooling water within this lake, which was originally designed, again, to handle two units. A couple of things I might point out here on the lake. The normal lake elevation pool level is 690. You will find that the site elevation grade is about 735, so there's approximately a 45-foot difference between the normal water level and the site grade.

The ultimate heat sink for Clinton Power Station, but not for the early site permit, is right in this area here, there is an underwater dam across here that keeps - should something happen to this dam, it holds the water in to keep it from flowing out. There is also a berm that runs down the middle of that, which I'll get a little bit more into on the next slide.

One thing I might show here is the discharge plume that comes out from the station. This discharge plume is used for Clinton Power Station and will also be used for the early site permit station and it discharges water approximately three and a half miles, back up to this arm of the lake, and so that the water runs around this way before it might run back out here, but of course, would have a difficult time going upstream to get back into the circulation here, should it still be in a heated temperature, which it normally would not be.

It would be well back into the normal lake temperature in this area. I believe that's about it. The last thing I would point out on this slide is that there is a fairly - there's Highway 54 that runs along here, that is the closest highway. Highway 10 runs south, along the bottom side of the lake there.

And there is a Highway - I believe it's 48 - that runs across here. All three of these do traverse the site and have been considered when we were looking at possible hazards.

One other thing that we looked at is that there is a railroad that approximately - well, runs alongside of Highway 54 for a good part of the ways and we also looked at it when we were looking at hazards.

The ESP location, again. What we see here is the exclusion area boundary, which is 1,025 meters. It's entirely on site property. This area here is Clinton Station, Unit 1. This shows that berm that I was referring to.

Again, the underwater dam goes across here and there is an underwater berm, this yellow line that goes out this way, a discharge from the lake during an ultimate heat sink cooling type event where that would be necessary. Discharge is on this side of the berm.

It then runs the length of the berm and around back to the intake structure before it is taken in again.

I mentioned this ultimate heat sink because if the plant that is ultimately chosen to be built on the early site permit property requires an ultimate heat sink, then the Clinton Power Station ultimate heat sink will not be that ultimate heat sink, but it will provide make-up to the ultimate heat sink. The ultimate heat sink in the early site permit structures would be mechanical towers, but the CPS ultimate heat sink, again, would provide make-up water.

The area for Clinton Power Station is here. This is the area where we would put the major structures for the early site permit. This area here is where we would build the normal cooling facilities, normal cooling towers.

This little - it was supposed to be a rectangle on here and it looks more like a line - but this area would be the ultimate heat sink, again, should one be required. Some of the designs that we're looking at do not require ultimate heat sink with a water source and water coolant.

We would also build an intake structure approximately here, between the berm and the intake structure for Clinton Power Station, and there would likely be some switch yard expansion necessary for additional facilities on this site.

This is a little bit different view. What I would like to point out here again, this is the area where the ultimate heat sink is. This is the intake structure. This is Clinton Power Station, Unit 1. This shows the hole that was as far as the Unit 2 construction got before it was cancelled.

This area is the area that occupies the primary structures for Unit 1. We did look at using the Unit 2 area for these additional facilities, but decided that the possible interferences with the operation of Unit 1 were more than we wanted to deal with, and so we looked at this area out here and this is what was chosen. It's a fairly flat area. It was previously disturbed as a lay-down area for the construction of Clinton Unit 1.

Again, this area would house the major structures. The intake structure would be here, water would go here, and we would use, again, the outflow canal that is over in this area.

Just a different view. Again, the intake structure here, that berm runs out this direction. Major structures for Unit 1 here. The hole. And again, this area out here that was primarily a lay-down area.

With that, I'd like to move to a little bit about the development approach that we used in the site safety evaluations and in developing the emergency planning information. In developing the site safety analysis report, we did make maximum use of the existing information. That's one of the benefits of using a site that already has an existing nuclear plant upon it.

We looked at that information, evaluated that information, and provided updates of that information, if necessary. In some cases, we did gather new data, either because the old data was not useful anymore, or we wanted to confirm that the old data - or the characteristic associated with the old data had not changed significantly.

Again, we have not chosen a design for this plant that might be built on this site at some future date, and so we developed a plant parameter envelope to use as a basis for evaluations of the impact of both construction and operation of such a plant on the surrounding area.

In order to do that, we looked at several designs that are underway or already have design certification, including the AP1000, which was underway at the time, and the ESBWR, which should be coming in soon.

We also looked at a few that you probably haven't seen yet. PBMR, for instance. The ACR-700, which is a can-do design at 700 megawatt level. A high-temperature gas reactor, MGT.

We took bounding aspects or characteristics of those designs, identified those as the parameters that we would use for the bounding parameters in the development of our evaluations, and so at COL - or for any COL that would reference this early site permit, then, we would be required to do a couple of things.

One thing is to verify that none of the site characteristics have changed and that the plant that is there or would be built would fit within those characteristics. The second thing would be to verify that the plant that we build actually fits within the plant parameter envelope that we used for our evaluations. Should any of those be exceeded, then we would have to address those in the COL application.

Turning to emergency planning information, again, we wanted to make maximum use of the existing plans there for Clinton Power Station. Exelon, of course, has a plan for that and the state and local areas also have existing plans. We did make maximum use of those.

For Part 52 for an early site permit, there are a couple of things that you are required to do. One is to identify any contacts with the local areas that have been made. You are required to make those contacts and then, of course, identify those. We did that.

We also looked at whether or not there were any significant impediments to developing a plan. Again, that is a requirement at 52.17 for an early site permit. We, of course, did not expect to find any impediments, since we have an operating plant on the site and an existing emergency plan in that area, and we did not identify any.

Now, beyond the required aspects, there are two possible options in the emergency planning area, neither of which are you required to do under an early site permit but, again, both are optional.

One of those options is to provide a complete and integrated emergency plan. We did not feel at the time we were putting this application together that we would be able to do that because we had not picked a design of the plant, and several aspects would be unknown because of that. Major items there might be the design and location of the on-site support center and the technical support center, for instance.

We did also - or the other option, however, is to provide the major features of an emergency plan, and that is the option that we pursued for this early site permit. We did provide a plan that identifies all of the major features, and those have been reviewed by the staff and we expect approval for those.

I would like to turn now away from the site location and provide just an overview of some of the information we provided yesterday in the geotechnical area. As you are aware, this latest supplement for the draft SER covered the geotechnical and seismic areas. We set out, of course - because we had a good deal of data on the Clinton Power Station and from Clinton Power Station on the geology of the area - we set out to confirm that the local soil properties under the early site permit area were the same as those that were identified for the Clinton Power Station.

We fully expected this, because some of the Clinton Power Station investigations encompassed the area that we were looking at for the early site permit. We did identify sufficient information to establish the site geotechnical characteristics for the early site permit, and we updated some of the dynamic soil properties for the specific piece of property that we were looking at. We did find the site suitable for future development.

With that, I'd like to ask if there are any questions on this portion of the presentation before I turn to the seismic development.

MEMBER POWERS: Are there any questions on this area? I think that we should just make the comment that in your examinations of the soil and whatnot, you did point out that it's relatively uniform throughout the site.

MR. GRANT: We did indeed.

MEMBER POWERS: There are always peculiarities in these things, but the --

MR. GRANT: Minor things in our parameters.

MEMBER POWERS: Nothing shocked you?

MR. GRANT: Absolutely not.

MEMBER POWERS: In that it's --

MR. GRANT: We found pretty much exactly what we expected.

MEMBER POWERS: And a relatively well-compacted soil structure it is, if below roughly 50 feet?

MR. GRANT: Correct.

MEMBER POWERS: And your intention is to remove that upper 50 feet and use an engineering fill, should you build the plant?

MR. GRANT: That's correct. I would say I believe it's 60 feet.

MEMBER POWERS: Sixty feet?

MR. GRANT: Yes.

MEMBER POWERS: Any other questions? Also, it is worth remarking that you did a relatively thorough examination of what limited amounts of hazardous chemicals and industrial activity there is in the vicinity of the site, including your major transportation corridors.

MR. GRANT: We did. As I mentioned, I looked at all the highway transportation and the roads in the area, as well as existing facilities that are stationary.

MEMBER POWERS: And finally, it's noteworthy that the staff raised a number of questions about your hydrology analysis and I believe you responded to those?

MR. GRANT: We have responded to all of the open items that were identified in the draft SER portion that was issued in February. We've only had the seismic draft SER supplement a few days and of course, have not even discussed possible resolutions with that on the staff. We've only had a few clarification type discussions.

MEMBER POWERS: That is an excellent point to make for the full Committee. The applicant has just recently seen the draft on the seismic portion of the new report, and so he's not in a position to respond to what he thinks about it.

MR. GRANT: We've had it less time than you have.

MEMBER POWERS: Difficult to imagine, but undoubtedly true. Okay, if there are no questions, please continue.

MR. GRANT: All right. With that, I'd like to turn the presentation over to Dr. Carl Stepp, who is going to discuss, again, the seismic features.

DR. STEPP: Thank you, Eddie. I'd like to start by elaborating just a little bit on the seismic review panel or review board, as you're characterizing this project.

The members of the review board include

myself, as Chairman; Professor Allin Cornell, who's well-known for his expertise in seismic hazard modeling and risk assessment; Dr. Kevin Coppersmith, who is one of our leading experts in the country in seismic source evaluation and uncertainty assessment for input to seismic hazard evaluation; and Dr. Walter Silva, who is one of the leading experts in the country in assessment of ground motion characteristics, strong ground motion characteristics.

We interact on an ongoing basis with the SER development team from CH2M Hill and Geomatrix, including planning activities for work to be conducted, meetings and telephone calls, so this was quite an interactive review process that took place, rather than simply a review of the final document. We greatly appreciated that and felt that the project benefited, and we certainly did, from the opportunity for that interaction.

The principal thing that I want to discuss here today, much shortened from yesterday, is the demonstration of how Exelon approached the determination of the SSE ground motion for the site.

In establishing the approach to the project, we identified that RG 1.165, first of all, though it was issued in 1997, basically contained 1990 timeframe technologies, and much has been done since the 1990 timeframe in this area, which allowed us to, I think, advance the technological approaches for implementing the regulatory guide.

The methods that we actually drew upon most was the ASCE Standard 43-05. That standard has recently been issued. It's a consensus industry standard which places the assessment of SSE ground motion on a performance-based methodology. I will address this more fully in later slides.

We also used an EPRI-advanced ground motion - or the new ground motion model, titled EPRI-03, which was a very extensive uncertainty assessment built into it, and we used results of that work in the project.

Finally, for the assessment of the site response, we used the methods contained in NUREG/CR-6728, which was the culmination, or the description of a very extensive five-year project sponsored by the NRC to address issues of determination of ground motion at a site.

These technologies have not yet gotten into either the RG 165 or the standard review plan, and we elected to adopt them, nevertheless, in our conduct of the work on this project.

The analysis is then consistent with the risk-informed, a performance that the Commission has began to adopt over the past several years, and we believe is also an advance in that area. And we believe that the performance-based methodology achieves a level of regulatory stability that was not achieved, though it was intended, by the reference probability approach that was adopted in RG 165.

MEMBER APOSTOLAKIS: Would you remind us what the performance-based approach is in the context of seismic, please?

DR. STEPP: Okay. I'm going to call on Dr. Kennedy for that.

DR. KENNEDY: This is Bob Kennedy. Basically, the performance-based approach starts out with assigning a performance goal. The performance goals that are in the ASCE Standard were primarily directed towards DOE facilities and they constitute five different levels of acceptable annual frequency of unacceptable seismic performance and four different limit states as to what constitutes unacceptable seismic performance.

The criteria used on this project was the highest of these, which basically had a goal of less than about ten to the minus five annual frequency of the onset of significant inelastic affirmation. That was a performance criteria that is a DOE performance criteria.

Studies have been done and indicate that that corresponds to seismic-induced core damage risk, typically in the range of 1E-6 to 4E-6.

So you start out with this performance goal. You start out with estimates of the seismic margin that exists in plant design to the standard review plan - or in ASCE, say, to the ASCE criteria, which is very close to the standard review plan.

Based on that, you back-calculate the ground motion level from the probabilistic hazard curve, you back-calculate the ground motion level that you need to design for to reach those goals. So rather than starting with a - some reference annual frequency of exceedance of a ground motion, such as RG 1.165 does, you start here, with a goal as to what you're trying to accomplish.

MEMBER APOSTOLAKIS: Thank you.

VICE CHAIRMAN SHACK: Just to follow up on that for a second. That sort of comes back to - roughly, it seems to work out in this case, you end up with like a ten to the minus four at the recurrence frequency, roughly, rather than the ten to the minus fifth that's in the Reg Guide.

When we look at initiators typically - we're examining now taking the large break out of the design basis - and we draw the line there, at ten to the minus five. If I look at something like seismic, which has the capability of affecting large numbers of components, why would I make the cutoff level of ten to the minus four instead of ten to the minus five?

DR. KENNEDY: This is Bob Kennedy again. I think I forgot to give my name the previous time, but I will answer that. I think there's a couple points you need to keep in mind. In RG 1.165, it talks about a median 1E-5 and that was arrived at on a relative basis using Livermoore hazard curves. At the time that was arrived at, Livermoore hazard curves, a median ten to the minus five, really a grade closer to a mean 8E-5.

There's a big difference between a median seismic hazard curve and a mean seismic hazard curve. What we're now talking about - in order to aim at a mean risk goal, you need to start with a mean hazard curve.

And so what we're now talking about is a mean hazard curve and this ASCE procedure will have, as a design response spectrum, a mean hazard curve that lies in the range of 3E-5 to 1E-4, depending upon the slope of the hazard curve.

Now, for the Clinton site, because the ground motion is relatively high, and it's a soil site, and you tend to start to saturate the ability of the soil to transmit even higher ground motion, the slope of the hazard curve between the ten to the minus four and ten to the minus five range is such that at ten to the minus five, the ground motion's about twice ten to the minus four.

For those kind of characteristics - for sites with those characteristics, the ASCE procedure leads to a ground motion that's very close to mean ten to the minus four. It cannot exceed mean ten to the minus four, but in the Clinton case, it is close. For many other sites with shallower slope hazard curves, it's more like mean 5E-5.

But first, you have to keep in mind that there's a difference between mean and median and the old RG 1.165 - well, it's not old - ten years old RG 1.165 is working with median hazard curves, but if you need to have risk goals, you'll want to work with median hazard curves. That is a confusion that quite often exists and there is substantial difference between mean hazard curves and median hazard curves.

DR. STEPP: Dr. Cornell?

DR. CORNELL: Pardon me. My name is Allin Cornell, consultant with Exelon. I'd like to add one comment further to your statement, and that is, you're comparing initiators. To exceed the SSE level is not that initiator. The SSE is simply a design basis level, beyond which there is significant margin before there's any onset of inelastic behavior.

DR. STEPP: Thank you. The performance-based methodology is now strongly supported by the industry as a more stable and regular basis for moving forward and developing SSE ground motion.

The NEI Seismic Issues Task Force is working very interactively with the NRC in developing a technological basis - helping to input those to the NRC - that will help to revise RG 1.165 and the standard review plan over the next year or so, hopefully sooner than that - maybe as short a time as nine months - to incorporate these procedures.

Now, the industry is doing this largely because we recognize that when you Committee forward in an application with a new approach that has not been reviewed fully by the staff in the past, that it requires a much higher level of scrutiny by the staff to make its decision and we are providing support through the NEI to facilitate and mature that process.

On the next few slides, I want to basically compare the methodology or the approach contained in RG 1.165 with the approach taken by the applicant in the Clinton ESP application.

First of all, I would point out that the work that we have done here complies with 10 C.F.R. Part 100.23 and it complies with that through the application of the guidance in RG 165 and I should also mention the standard review plan.

The one variation, which we've dwelt on a little already and you've heard quite a lot about, is the use of the ASCE Standard 43-05. It's titled "Seismic Design Criteria for Structures, Systems, and Components in Nuclear Facilities".

It is a performance-based criteria, as you've heard, and it is an industry consensus standard, so it has the authority of being embedded over some period of time by the industry.

The comparison of the RG 165 with the EGC application approach - the investigations that are required by the Reg Guide were fulfilled in the EGC application approach - involved updating of the geology, seismology, geophysics, in the 200-mile region of the Clinton site, and the performance of an assessment of the importance of new information compiled on the existing EPRI SOG seismic sources, seismic source characterizations that were used in the mid-1980s, in 1985, and approved by the NRC in 1989.

That updating of the seismic source characterizations was performed, applying a level two SSHAC - that's the Senior Seismic Hazard Analysis Committee that was commissioned jointly by the NRC, DOE, and EPRI some years ago to assess and provide guidance for the quantification of subjective uncertainties in seismic source input interpretations.

Those updates indicated that there could be significant differences in the hazard at the Clinton site because of new information, so a PSHA, a new PSHA, was conducted as directed by RG 165.

As I said, and I've emphasized, the departure came when we actually started to compute the ground motion, deriving the ground motion from the hazard, and instead of using the relative-based reference hazard criterion contained in 165, the ten to the minus five median annual hazard, we elected to apply the ASCE approach, which is performance-based.

We also followed RG 165 completely in our development of the ground motion through the de-aggregation of the hazard and the identification of the controlling earthquakes before the site. We accounted for the site effects - the response of the local geology of the site and its effect on ground motion.

It really, in the same - in compliance with the 165 and, more directly, the standard review plan, but we updated the guidance currently contained in the standard review plan by applying NUREG/CR-6728 methodology, which has not yet quite gotten into the practice - into the standard review plan.

Just a little more on the hazard comparison, I think this has been touched on already, but we probably could go ahead and walk through it. The reference hazard criterion is described in - the best place for it, it is described in Appendix B to RG 1.165.

It is based on the annual probability level such that 50 percent of the set of the most modern design - currently, operating plants by the most modern design, those are the plants that were reviewed and licensed under Appendix A to 10 C.F.R. Part 100, and have been designed to the RG 160 standardized spectrum, such that that set of plans has an annual medium probability of exceeding the SSE that is below this level and that turns out to be 1E-5 median, determined at an average response spectral frequency of five to ten hertz, a five percent spectra.

The performance-based approach is based on SSCs that have a target mean annual frequency of 1E-5; have got seismic onset of significant inelastic deformation in the plant; with a significant margin against SSC failures that might lead to core damage. It's very significant in this by assuming the onset of significant inelastic deformation.

This leads to seismically-induced core damage frequencies that are significantly less than those of existing plants, and I think we could elaborate that a little bit with work that has been ongoing with the NEI and EPRI project.

MEMBER SIEBER: When you talk about significant margin, could you give us a quantitative --

DR. STEPP: Yes, I think we can give a quantitative margin. Dr. Kennedy can address that from some recent work that he has done.

DR. KENNEDY: This is Bob Kennedy again. Generally in the nuclear industry, we talked about seismic margins in terms of what has often been called high confidence, low probability of failure seismic margin, which corresponds, on a mean basis, to a mean probability of unacceptable performance of about one percent.

Now, in the ASCE method, for the onset of significant inelastic deformation, the seismic margin against onset of significant inelastic deformation - when you design to the standard review plan or the criterion ASCE 43-5, either one, that seismic margin is assumed and estimated to be about 1.0.

When you look at core damage, from past seismic PRAs and from studies and from NUREG-6728 and from experience on the advanced designs, the core damage seismic margin - again, a cyclic type seismic margin, is estimated to be about 1.67, so the difference between the onset of significant inelastic deformation and core damage, that factor is estimated to be about 1.67.

That's what causes that if you're at a less than 1E-5 annual frequency of significant inelastic deformation, then typically, the approach leads to .5E-5 to 1E-5 - the ASCE approach for that onset of significant inelastic deformation - that corresponds to core damage in the neighborhood of 1E-6 to 4E-6.

There are studies that will show all of

that; unfortunately, I don't think they have yet been released by NEI to the NRC, so the information I've passed to you, it's unfortunate, it has not yet made it to the NRC staff and so it hasn't been reviewed by the NRC staff and it's, therefore, my understanding of those studies and there needs to be a lot of debate and discussion with the NRC staff on these issues.

MEMBER SIEBER: Thank you.

DR. STEPP: And finally, the last slide I will address here shows the EGC ESP SSE ground motion spectra for both the vertical and the horizontal spectra. These derived spectra are performance-based. They fall well below the RG 1.60 spectrum - standard spectrum anchored at 0.3g - that's the basis for the standard plant design - in frequencies that are lower than 16 hertz.

They exceed - this horizontal exceeds the RG 1.60 spectrum at frequencies above 16 hertz, over a range, and the vertical exceeds frequencies above 20 hertz over range. The maximum of the exceedance is like a 33 hertz, and that's about 25 percent. We believe that this exceedance and this range is negligible in terms of its damage potential.

The principal response frequency range of the plant systems and structures and components is generally below 10 hertz, so these are well outside the principal response range of the nuclear plant systems and are relatively minor in their amplitude. That concludes my presentation.

MEMBER POWERS: Are there any questions on this seismic - we'll go into the seismic a little more when the staff presents.

MR. GRANT: Thank you, Dr. Stepp. Last thing I'd like to do, then, is provide a quick summary. The early site permit site that we're requesting approval for is next to an existing operating nuclear plant, Clinton Power Station.

When developing the application, we maximized the use of existing information and, of course, because we had not identified a particular design that we might use for this future facility, we have identified a plant parameter envelope, established that and used that in our analysis.

MEMBER POWERS: I think it's worth noting to the full Committee that this - that the plants considered involved in this plant parameter envelope are familiar to us from other applications.

MR. GRANT: Right, both Grand Gulf and North Anna have used the same type of thing. We worked extensively with them through NEI in development of that plant parameter envelope, and I believe we all used the same envelopes - or at least the same parameter envelopes. There were a few minor differences in some of the values, for various reasons.

The site characteristics were identified in the application, which was the major purpose of the site safety analysis report portion. Again, as discussed in detail yesterday afternoon in the geotechnical area, the site is a simple and suitable - or has simple and suitable site geology.

We have determined the SSE ground motion, using what we consider the latest regulatory guidance and the latest industry practice. Finally, of course, our early site permit is requesting a 20-year lifetime for that permit.

MEMBER POWERS: Any questions to pose to the applicant? Did you have a closing comment?

MS. KRAY: Thank you. No, I just wanted to thank you for your attention and also acknowledge the effort of the staff, also, for the issuance of the draft safety evaluation reports and we certainly look forward to continuing our discussions on the seismic issue.

MEMBER POWERS: You look forward to it?

MS. KRAY: We do.

MEMBER POWERS: I think that's outstanding. Well, thank you.

MS. KRAY: Thank you.

MEMBER POWERS: We'll now ask the staff to present and, John, you're going to lead off?

MR. SEGALA: Yes.

MEMBER POWERS: Our speaker will be John Segala from the staff, who's the project manager for this activity. Again, what I have asked the staff to do in their presentation is not to reiterate the discussion, but to try to plunge immediately into what their ongoing activities are going to be in this. To you, John.

MR. SEGALA: All right, thanks. Again, I'm John Segala, the lead project manager for the Exelon early site permit application review. To my left is Dr. Cliff Munson, who is the seismic reviewer for the staff and he's going to assist in the discussion of the seismic open items.

The purpose of this discussion is to provide the status of the staff's safety review, to provide an overview of the remaining open items, and to support the full Committee in issuing their interim letter to us, and to answer your questions.

We're going to discuss very quickly the key review areas, a high-level discussion of the permit conditions and the COL action items, a few DSER conclusions for sections that didn't have open items, and discuss open items which remain open, and touch on some of the scheduled milestones.

This slide is a list of the key review areas. I'm not going to discuss that in detail. The next slide, we had eight lead technical reviewers. Brad Harvey reviewed meteorology. Goutam Bagchi reviewed hydrology with support from PNNL. Kaz Campe reviewed site hazards, with contract support from PNNL. Cliff Munson and Tom Cheng reviewed geology, seismology, and geotechnical, with support from the U.S. Geologic Survey and BNL.

Jay Lee reviewed demography, geography, and radiological consequence analysis. Bob Moody reviewed emergency planning with consultation with FEMA. Paul Prescott reviewed quality assurance. Al Tardiff reviewed physical security.

Considering both the draft safety evaluation report and the supplemental draft safety evaluation report, there were a total of 15 proposed permit conditions and 17 proposed COL action items. During the review, going from the North Anna early site permit draft safety evaluation report to the final report, we established a set of new criteria for determining how to bend these items and what characteristics determine where these items should belong. We are currently in the process of applying that new criteria for the Clinton review, so I'm not going to go into any more detail regarding that, because we expect the number of permit conditions to decrease and the number of COL action items to increase.

Real quick, with the sections that didn't have open items, some of the conclusions that we made is that the potential hazards associated with nearby transportation routes, industrial and military facilities, proposed no undue risk to the facility that might be constructed at the site.

The proposed site is acceptable, with respect to the radiological effluent release dose consequences from normal operation and the site characteristics are such that adequate security plans and measures can be developed.

MEMBER DENNING: Could you take me quickly back to seven?

MR. SEGALA: Sure.

MEMBER DENNING: I was just wondering, the very first conclusion, was that just a standard conclusion? Does that have any significance at this point, or do you normally just defer to the FSER?

MR. SEGALA: Yes.

MEMBER DENNING: Is there any significance to that statement?

MR. SEGALA: Well, we issue the draft with open items and we're now in the process of trying to resolve open items and issue the final. The applicant has responded to all of the draft open items, and we have come to resolution on most of those, and the staff is writing their input to the final, so when we issue the final report, we will come back to you and have another discussion where we will describe to you how we resolved all the open items.

The draft safety evaluation report had 33 open items and the supplemental draft safety evaluation report on seismic had seven open items. The number of open items is not a measure of the significance of the open items.

All the draft safety evaluation report open items are resolved, except for the seven supplemental seismic open items, as well as one hydrology open item, and this item is with respect to the maximum ice thickness. The staff has concluded that there is an adequate amount of water in the ultimate heat sink for make-up.

The question that we're still trying to figure out is, what is the exact number that we should be using for the site characteristic for the maximum ice thickness? And we're having discussions with the applicant to resolve that.

We had five confirmatory items. All of those are resolved, except for one, which is just to verify that the open item responds and the RAI responses that had mark-ups, that they actually get reflected in the final revision to the application.

With regard to the supplemental draft safety evaluation report, we had seven open items. We had two open items, 2.5.2-4 and 2.5.2-5, regarding the performance-based approach that the applicant has proposed. I think pretty much everything on this slide, they've discussed earlier.

As we mentioned, the applicant hasn't had time to respond to the open items in the supplemental, and so the staff is prepared to discuss the open items, but not to discuss potential resolutions to the open items. We have a meeting that we're trying to schedule with the applicant later this month to discuss the open items in detail.

The staff is reviewing the applicant's final safe shutdown earthquake to determine the appropriateness of the performance-based approach. At the bottom of the slide, open item 2.5.2-5, the staff has questions regarding some of the assumptions underlying the performance-based method.

For instance, the staff has asked the applicant to justify why a beta value of 0.4 was used, clarify the meaning of onset of a significant inelastic deformation, and justify the long-term stability of the target performance goal E-5, and there's other items that I won't get into.

With regard to open item 2.5.2-4, the staff has determined that the performance-based spectrum for the safe shutdown earthquake spectrum for the early site permit site is approximately equal to the mean E-4 uniform hazard spectrum and the performance-based safe shutdown earthquake at E-4 may not adequately represent the seismic hazards from local earthquakes.

This next slide is the comparison for the performance-based safe shutdown earthquake spectrum for the early site, permit site, and the mean E-4 and E-5 uniform hazard spectrum. As you can see with the black line in the middle, it is approximately equal to the mean E-4 uniform hazard spectrum.

This slide shows the local earthquakes near the site. Paleoliquefaction features indicate a local earthquake in Springfield - magnitudes of 6.2 - or at least 6.2 - and these happened between 6,000 and 7,000 years ago. The Wabash Valley earthquakes are in this are, and the magnitudes are shown on that graph.

In conclusion, with regard to the performance-based, the staff feels that the performance-based approach with a target of E-5 annual performance goal may not be suitable for determining the safe shutdown earthquake for the Clinton early site permit site.

With regard to some of the other seismic open items, the open item 2.5.1-1, the applicant originally used a pre-print of a paper for determining the magnitudes for the New Madrid earthquake.

Once the paper went to press, the magnitudes - the authors increased the magnitudes slightly, so the staff asked the applicant to go back and redo their analysis with the higher magnitudes. The applicant did that, but did not incorporate it into their probabilistic seismic hazard analysis or their safe shutdown earthquake, and the staff is asking them to do that.

The staff, for open item 2.5.2-1 - the staff found that the description of the distance conversion method in the application was not clear and is asking the applicant to clarify and justify this distance conversion method.

The next three open items are related to the geotechnical review. Open item 2.5.2-2 - the staff initially had questions about the variability and site properties, such as shear wave velocities and standard penetration test flow counts, which occurred in the top 50 feet of the site.

The applicant responded, disputing our observations. In subsequent discussion, the applicant indicated that the top 60 feet will be removed and the staff is considering this in their review of the status of this open item.

Open item 2.5.2-3 - the staff is questioning if the EPRI shear modulus and damping curves are appropriate for the site. Open item 2.5.4-1 is more of a clarification item where the application states that at the COL stage, they're going to determine whether additional drilling and sampling is needed, and the staff feels that there's enough variation in the soil properties within the ESP site to necessitate further exploration at the ESP site, so we're asking them to clarify what's written in their application.

With regard to the completed milestones, we received the application in September of 2003. We issued the draft safety evaluation report on February 10, 2005, and we issued the supplemental draft safety evaluation report on August 26th and we brief the subcommittee yesterday.

The remaining milestones were requesting an interim letter by September 28th. The staff is planning to provide the final safety evaluation report - an advanced copy to the ACRS - on February 8, 2006.

The staff plans to issue the final safety evaluation report in February of 2006, and that issuance date is dependent on the resolution of all of the open items in the supplemental draft safety evaluation report by the end of October.

The ACRS full Committee meeting on March 9, 2006 and a final letter by March 30, 2006, and the staff would incorporate that letter into the final SERs and NUREG on May 1, 2006, with mandatory hearings beginning in the Fall of 2006 and Committee decision around mid-2007, although those two milestones are out of our control.

In summary, all of the open items are

resolved, except for seven seismic open items and the one hydrology open item that I mentioned earlier. We're working to resolve the remaining open items and we look forward to receiving the interim ACRS letter.

MEMBER POWERS: Any questions of the speaker? If I might just turn to your plots of the ESP, SSE, and uniform hazard spectrum at E-5 and E-4, I understand these UHS spectra are means?

MR. SEGALA: Yes.

MEMBER POWERS: If I were to plot medians at the same probabilities, could you give me an idea of where they would fall? I don't need ten to the - I don't need high precision. Lower or higher is good enough for me.

DR. MUNSON: The medians would be higher.

MEMBER POWERS: Higher. Any other questions?

MEMBER APOSTOLAKIS: Just a quick question. Is in your mind, the performance-based approach is the same as a risk-based approach? Or do you think it's different?

MEMBER POWERS: You're asking the wrong one, George.

MEMBER APOSTOLAKIS: Well, they used the words. On Slide 10, you're referring to a risk-based approach. Or is it just a slip of the tongue?

DR. MUNSON: There's elements of risk involved in the performance-based approach, but

MEMBER APOSTOLAKIS: Well, yes, we're talking about probabilities of various --

DR. MUNSON: Right, but commonly, it's referred to as performance-based approach.

MEMBER APOSTOLAKIS: So it's not risk-based?

MEMBER POWERS: Well, how do you escape risk, in looking at seismic?

MEMBER APOSTOLAKIS: Well, there has been a reluctance to use the word “risk-based” in this agency. It’s “risk-informed” usually.

CHAIRMAN WALLIS: Risk-based means use of a PRA, doesn't it? It's irrelevant.

MEMBER APOSTOLAKIS: Exclusively, which we don't want to do.

MEMBER POWERS: Any other questions? Any answerable questions?

MEMBER APOSTOLAKIS: On Slide 14, you say that performance-based approach gives a target E-5 may not be suitable. Can you clarify, tell me why it may not be - is it the numbers they're using or the approach, or both?

DR. MUNSON: Well, we have open items regarding the underlying assumptions?

MEMBER APOSTOLAKIS: Assumptions and the approaches.

DR. MUNSON: And also - we want to - our task as the staff is to ensure that the final SSE adequately represents the seismic hazard.

MEMBER APOSTOLAKIS: No, I understand.

DR. MUNSON: Whether they used performance based or 1.165, any approach, that's our most important objective, so those are the two open items, basically.

MEMBER DENNING: When you're asking for an interim letter at first now, obviously, you have an issue that's not - which is a substantial issue. What are you looking for? What are you expecting us to say?

MEMBER POWERS: They're looking to see if we have an issue.

MS. DUDES: Well, let me chime in a little bit here. I know that you've had - this is Laura Dudes, Chief of New Reactors – that you've had the bulk of the draft safety evaluation report for quite some time, and I know you can get through that and comment and provide us feedback on that, similar to the other ESPs.

With respect to the seismic issue, I think we all need to understand that and I think Marilyn alluded to this in her opening remarks, that we're - the staff is reviewing this performance-based method in conjunction with an application, and that's a big challenge. We want to be careful. We want to be thorough in this review.

And we want to achieve an agency-wide consensus, which is one of the reasons for the delay and issuing the supplement is that we need to go across offices to get the right information, and to make sure that the review that we do here and what we write in our safety evaluation report, that will set precedent as we go forth and generically approve this performance-based method.

So I'm not sure if we're ready to respond. Obviously, the applicant's still looking at our open items. The staff has developed questions. We need to still have some frank technical conversation on the responses to those questions and those answers, so perhaps to the extent that you feel comfortable to respond in the interim letter on the seismic issue, but to really focus more on the bulk of the draft document, and we can bring you more closure and more information at a later time with respect to the seismic issue.

CHAIRMAN WALLIS: Does the staff have the ability to understand this approach? I found it very difficult to understand. Do you bring in consultants or something, or how do you figure out this rather unique approach?

DR. MUNSON: This is Cliff Munson. It has been a difficult review for us. We have obtained, not just in our review of this, but also, we formed a Seismic Task Advisory Group with members of research at NMSS, and we've also contacted with a USGS civil engineer also to get some outside review help for this, so it's an ongoing process, and I believe we've got a handle on it now - a pretty good understanding.

MEMBER POWERS: Any other questions?

MR. YOUNGS: Yes, this is Bob Youngs with Geomatrix Consultancy, a consultant to Exelon in helping develop the safety evaluation report. I just wanted to make a comment or ask for a little bit of clarification about the question on Figure 12, whether the means or medians would be higher, and in terms of - I wasn't sure that I heard Cliff correctly in indicating that these are mean spectra and that the median spectra under the same annual frequencies of exceedance would actually be lower than the means. I wasn't quite clear what --

DR. MUNSON: Actually, in recent hazard evaluations, the mean and median are much closer together than - I mean, it might be slightly lower.

MR. YOUNGS: Thank you.

MEMBER POWERS: Any other comments?

CHAIRMAN WALLIS: You said it was higher - didn't you say it was higher?

DR. MUNSON: If you look --

CHAIRMAN WALLIS: It's possible it might be lower? What is it?

DR. MUNSON: It doesn't matter, really.

CHAIRMAN WALLIS: It doesn't matter? Okay.

MEMBER APOSTOLAKIS: The median is usually lower, isn't it?

MEMBER POWERS: Any other questions? Thank you very much. I've been asked to inquire if there are any members of the public that would like to comment on this application and the staff's review? I see no one jumping to the opportunity I dangle in front of them and so I will turn it back to whomsoever now thinks he's in charge. Welcome, Mr. Wallis.

CHAIRMAN WALLIS: I assume that that's the last thing we have to do before lunch?

MEMBER POWERS: It is.

CHAIRMAN WALLIS: So we have, in my absence, gained an enormous amount of time?

MEMBER POWERS: The source of delays that we've have in the past.

CHAIRMAN WALLIS: That's right. That explains a lot. Okay. So we will adjourn to lunch and come back here at 1:30, and we have some interviews to conduct over the lunch break.

(Whereupon, the above-entitled matter went off the record at 11:33 a.m. and resumed at 1:35 p.m.)

CHAIRMAN WALLIS: Please come back into session. Good afternoon. The next item on our agenda is the proposed Revision to Regulatory Guide 1.82, Revision 3. I'll invite my colleague, Victor Ransom, to lead us through it.

MEMBER RANSOM: Okay. I'll give just a very brief introduction. This is an issue that goes back 35 years, I guess. In 1970, Reg Guide 1.1 was issued, which expressed the principle that containment overpressure should not be allowed, and since that time there have been a number of provisions to the Reg Guide.

In 1972, Reg Guide 1.82 was released, and it also did not include granting containment overpressure. However, overpressure has been granted in cases where existing plants required credit to avoid extensive equipment upgrade, yet could assure the NRC that safe operation could be maintained for the design basis accidents.

The ACRS has been involved, too. In 1997, the ACRS stated that it believed some level of overpressure credit is not acceptable corrective action. They then later -- six months later -- changed that and reversed that position, concurring with the NRC staff, and selectively granting credit for small amounts of overpressure may be justified.

And Revision 3 to Reg Guide 1.82, issued in November of 2003, incorporated granting credit, but not go so far as to withdraw Reg Guide 1.1, which left a little bit of conflict.

Just recently, July 19th, our Thermal-Hydraulic Subcommittee had a meeting, and I'll just give a brief summary of tech conclusions that came out of that.

Basically, the proposed Revision 4 to Reg Guide 1.82 lists many phenomena that must be dealt with, but provides very little guidance as to how to account for them. That seemed to be a concern for the committee. They expressed some desire to see a degree of conservatism by performing realistic calculations for comparison to a conservative approach. This hasn't been done, but there was interest in seeing something on that level.

Also, Revision 4 seems to be a work-in-progress since it was stated that beyond design-basis accident criteria were not yet included, and the degree of conservatism in treatment of debris has yet to be determined.

With that, there was general agreement on the committee that the proposed Revision 4, which attempts to bring the guidance in line with practice, should come to the full committee for consideration of whether it should be released for public comment. So, that's kind of where we're at right now. With that, I'll turn to the first speaker, which I'm not sure who is going first. Okay. Richard Lobel will go through the Staff's position, or summarize the proposed revision.

MR. LOBEL: Good afternoon. My name is Richard Lobel. I'm a Staff Senior Reactor Systems Engineer in the Office of Nuclear Reactor Regulation, NRR. Seated next to me is Marty Stutzke, who is a Senior Reliability and Risk Analyst, also in NRR.

We're here today to discuss the proposed revision to Reg Guide 1.82, Revision 3, as well as several other related documents. The purposes of the revision are to make the regulatory guidance on NPSH consistent between these documents, and to revise the regulatory position on crediting containment accident pressure in determining NPSH. As part of this effort, the Staff has reassessed our position on the use of containment accident pressure in determining NPSH margin. A large portion of our talk today is devoted to this reassessment, and the purpose of the presentation is to request ACRS approval to issue this proposed revision to Reg Guide 1.82, Revision 3, for public comment.

The documents being revised as part of this effort are Reg Guide 1.82, Revision 3, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident"; Reg Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps"; Standard Review Plan Section 622, "Containment Heat Removal Systems", and the Review Standard for Extended Power Upgrades, which is an NRR document.

This last document hasn't been revised yet. The NPSH revisions will be made at the same time as the other revisions to this document, and last I checked there hadn't been a schedule set for that.

Actually, the Staff's intent is to revise Reg Guide 1.82, Revision 3, and reference this revision in the other documents. Some of these documents deal with broader issues than NPSH, but we're here today only to discuss NPSH. No substantive changes have been made to any other area of these documents.

The NPSH guidance supplies mainly to ECCS and containment heat removal pumps during a LOCA or other events, when the PWR pumps are taking suction from the emergency, or the BWR pumps are taking suction from the suppression pool. The main focus is on the design-basis LOCA, but as part of the reassessment we examined all pertinent events.

We divided the technical justification for crediting containment accident pressure for NPSH into five categories: containment integrity -- will the credited pressure be available, calculation conservatism, confidence that licensees will not underestimate the NPSH margin, and the additional of whether there may actually be too much conservatism in these calculations; pump design -- what would happen to a safety-related RHR core spray or containment spray pump if it were cavitating, the impact on emergency operating procedures of taking credit for containment accident pressure; and, finally, the risk -- what is the effect of crediting containment accident pressure on the overall plant risk.

The NRC has allowed credit for calculated containment accident pressure in determining available NPSH of the emergency core cooling system, containment heat removal system pumps in some boiling water reactors, and to a lesser extent in pressurized water reactors. We allow this credit when a conservative analysis is demonstrated that this amount of pressure will be available for the postulated design-basis accident and, when examined from a broader perspective -- that is, beyond design-basis accidents -- the level of risk is acceptable. This is the current Staff position.

MEMBER POWERS: Has any plant failed to meet that criterion?

MR. LOBEL: Nobody has -- we haven't ended any reviews or found any reviews unacceptable because of those criteria but, as with many of our reviews, there's a lot of discussion and negotiation and changes in position -- you know, finding some things not acceptable and revising analyses and that kind of thing. That's happened.

MEMBER POWERS: How do you get -- I mean, how do you get a situation in a design-basis accident where you will not have some substantial amount of pressurization? The only way I can think of doing it is you leave the containment open.

MR. LOBEL: Well, I'm going to talk about that. The two ways that were identified in Reg Guide 1.1 was an undefined loss of containment integrity. For some reason, there's a large enough hole in containment that there's sufficient leakage that you can't maintain the pressure. And the other was using containment sprays and spraying down to the point where you reduce the pressure. Those are the two that were identified in Reg Guide 1.1, and those are the ones that --

MEMBER POWERS: But, you see, those are the old condition having the DBAs, so -- I mean, the probability is so low that when you calculate risk, you're never going to hit it. I mean, it's not a limit on anything.

MR. STUTZKE: I'll give you the exact risk numbers a little bit later, but you're right, the risk is very small, as best we can calculate it.

MEMBER RANSOM: Well, there has been

concern expressed over the operator -- I guess to have an analysis go conservatively, the operator has to be involved because normally he's told to spray down the containment to keep pressure down, but yet he also is charged with keeping pressure up in order to meet the minimum NPSH requirements, and that seems to be a concern.

MR. LOBEL: The procedures for boiling water reactors tell the operators typically -- and the EPA says tell the operator that he can spray down and terminate the sprays when the pressure gets to zero PSIG. That's for a boiling water reactor that isn't taking credit for containment pressure for NPSH. I was going to talk about this a little later, but for a plant where credit is being taken, there will be a value of pressure defined in the emergency operating procedures in place of the zero PSIG. A higher pressure will be specified. And the operator will use the same procedures of control to that pressure.

So, the basic procedure for watching the sprays and terminating the sprays is already in the emergency operating procedures. The only thing that changes with a change to the pressure is the value. I'm going to talk more about that later.

It's important to point out that there's no regulation that prohibits crediting containment accident pressure for available NPSH. We're dealing with NRC Staff guidance on crediting this pressure.

The background on this issue -- Dr. Ransom went through it a little, I'll try to go through it briefly -- goes back -- the background goes back even before Reg Guide 1.1, which was issued in November 1970. Reg Guide 1.1 dealt exclusively with this issue of crediting containment accident pressure, and recommended that credit not be used.

The position of Reg Guide 1.1 states that no credit should be given for any increase in containment pressure from that present prior to postulated loss of coolant accidents. The NRC allowed credit for containment accident pressure for some reactors licensed before the issuance of this Reg Guide, and reactors licensed after issuance of the Reg Guide generally complied with the guidance.

CHAIRMAN WALLIS: Is this Reg Guide still current? It hasn't been modified 'til now?

MR. LOBEL: Right, it hasn't been modified. It should have been done as part of the work that was done in issuing Reg Guide 1.82, Revision 3, and it was intended that it be done, but --

MEMBER RANSOM: But you are going to do

that in Rev 4, I guess -- withdraw.

MR. LOBEL: We are going to do that now. And I'll talk about that a little more later, but the idea is that we're not going to withdraw that Reg Guide because some reactors still use it as part of their licensing basis. So, we're going to add a note to the Reg Guide that says that it shouldn't be used in the future, after issuance of Revision 4, but that it's still acceptable for plants that already have it as part of their licensing basis, since it's a conservative position -- more conservative position.

After several BWR ECCS suction strainer blockage events, one at the Baersback reactor in Sweden in 1992 and several subsequently in this country, and extensive research and development, the NRC issued Bulletin 9603. All BWRs complied with the recommendations of this bulletin by installing larger, better designed suction strainers.

The design of the strainers took into account plant-specific suction strainer debris loadings of several types of materials and, in general, these loadings were predicted to be much higher than anticipated prior to these events. This resulted in an increase in the predicted flow resistance across the strainers, which resulted in a decrease in the calculated available NPSH. So, in some cases, this necessitated credit for containment accident pressure.

CHAIRMAN WALLIS: I'm not quite sure what you mean there. I thought that you were defining NPSH independent of the strainers and enough margin in NPSH to overcome the pressure drop across the strainers. You spoke as if the strainer pressure drop was itself figured into the NPSH calculation, which I don't think is the case.

MR. LOBEL: Well, it can be done either of two ways.

CHAIRMAN WALLIS: But your guide seemed to make it very clear, you calculate the NPSH first, and then you do the pump strainer calculation and see if the NPSH is enough to overcome that.

MR. LOBEL: That's the way it was defined, and that's the way some -- that's the way it was written into the Reg Guide Revision 2, and so we kept it that way. But, really, you can do the calculation either way. If you include the margin -- I'm sorry -- if you include the debris term, the loss term then you compare that directly to the required NPSH.

CHAIRMAN WALLIS: I think there's something in the document -- I'm sorry, I lost my notes -- that says that the NPSH -- adequate margin is equal to the sum of strainer pressure drop. So, you're making two different calculations and comparing them.

MR. LOBEL: Right, and that's one way to do it, but it's equivalent to do it the other way in include the pressure drop due to the debris in with the other losses, and do the calculation that way. And in that case, instead of comparing with the -- instead of comparing with the debris term, you calculated the total available NPSH and you just compare that to the required NPSH. If you do it without including the debris loss term, you've not calculated the total available NPSH. I have a slide that shows that, but I didn't put it on the CD. It's just a matter of algebra on which side you put the --

CHAIRMAN WALLIS: You don't need to go from the required NPSH and take off the drop over the screens and you get back to the containment pressure, and if it's less than the normal pressure, why, of course you have excess NPSH available. If not, why, you need credit.

MR. LOBEL: Right, and that's how the calculation is done.

I don't have a slide with the equation,

but did you want to talk about this some more?

CHAIRMAN WALLIS: No, I just want to be clear on the definition, that's all.

MR. LOBEL: I can discuss it later. Okay. So, in some cases, because of strainer blockage, BWRs needed to take credit for containment accident pressure. And as a related issue, in 1996 and '97, as a result of NRC inspections and licensee event reports, the NRC staff became aware that the available NPSH for some of these pumps may not have been adequate in all cases, and this applied to both PWRs and BWRs.

In order to understand the extent of the problem, the NRC issued Generic Letter 97-04 requesting licensees to provide current information regarding their NPSH analyses. Generic Letter 97-04 did not contain any requirements or requests for actions other than a response to the questions on the NPSH calculations, including questions on credit in containment accident pressure.

In some cases, in response to the Generic Letter, licensees revised their NPSH analyses, and in some of these cases licensees proposed credit for containment accident pressure in calculating NPSH. The NRC reviewed all the responses and formulated --

as part of that review, formulated acceptance criteria, and these criteria weren't documented in a publicly available source at that time, except in individual safety evaluation reports.

In order to document these criteria for future use and to make them available to stakeholders, the NRC Staff included them in Reg Guide 1.82 Revision 3, including regulatory positions on NPSH, and this Reg Guide provides one reference for all regulatory positions related to pump suction issues -- vortexing, air entrainment, debris blockage, as well as NPSH -- and Revision 3 was published in November 2003.

The Staff briefed ACRS twice on NPSH and credit for containment accident pressure, once before and once after issuance of Generic Letter 97-04. In the last briefing in December of 1997, the Staff particularly covered the area of beyond credit for containment pressure and beyond design-basis accidents, and the ACRS wrote a letter to Chairman Jackson which concurred in the Staff position, but urged that all accident sequences should be examined. And as you will see, we've including your recommendation in this reassessment. Reg Guide allows credit for containment accident pressure. Reg Guide 1.1, in the Standard Review Plan, Section 622, do not, and the proposed revisions now will fix this inconsistency.

Reg Guide 1.82 Revision 3 states that Containment accident pressure should only be credited when the design cannot be practicably altered." It goes on to state that "No additional containment pressure should be included in the determination of available NPSH than is necessary to preclude pump cavitation."

We're proposing to change these positions to the position I stated earlier, which emphasizes safety and is more consistent with the Staff reviews.

MEMBER RANSOM: I find that statement a little strange. Why would they want to include more than enough to preclude pump cavitation?

MR. LOBEL: Well, the calculation for the containment pressure is done in a conservative way, and there really isn't any reason not to permit use of the pressure up to that conservatively calculated value. Limiting the pressure in the calculation really doesn't do anything practical, it has no effect on what the actual pressure would be in the containment. There's no restriction on it that way. So, it's really just kind of an artificial device that was put in to add another degree of conservatism.

MEMBER RANSOM: Well, the question would be I don't think it adds anything because if you included enough credit to preclude cavitation and that's all you want to do, then that sets the level in which the containment pressure is presumed to exist.

MR. LOBEL: Well, the thinking was just that there didn't seem to be a good reason for having a restriction less than the conservatively calculated pressure. It really didn't accomplish a whole lot because if the licensee calculated one value and then found a problem and fixed the problem and was still under the conservatively calculated pressure, there really wasn't any reason why they couldn't increase their limit that they were using. And so it really wasn't contributing anything. Like I say, it had no effect -- it had no effect on the containment analysis, and it has really no effect on what would actually happen in the containment, it was just an artificial limit.

The Staff proposes revising the position, the position I stated earlier. Like I was saying before, Reg Guide 1.1 won't be used for any future reviews. It's not being withdrawn because it's still part of the licensing basis for some reactors. And we propose to add a note to the Reg Guide to reflect this position.

Standard Review Plan Section 622 is also being revised to be consistent with the Staff position on crediting containment accident pressure, and it will do that by referencing Reg Guide 1.82.

MEMBER RANSOM: It currently references Reg Guide 1.1, and that will be removed, I guess?

MR. LOBEL: Yes, it will be.

CHAIRMAN WALLIS: So, essentially it's always allowed as long as it's calculated conservatively.

MR. LOBEL: That's right.

CHAIRMAN WALLIS: So it's allowed. It's allowed, and then you've got to calculate it conservatively.

MR. LOBEL: Right.

CHAIRMAN WALLIS: So it isn't really allowed when, it's just allowed, and these are the conditions on it.

MR. LOBEL: Right.

CHAIRMAN WALLIS: So when it's allowed, you have to do these things.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: Essentially, it's now allowed. As long as you follow the rules, you can do it.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: You don't have to apply for any permission or anything, you just do it.

MR. LOBEL: Well, a change like that would most likely trigger a prior Staff review and approval by 50.29, 10 CFR 50.59. In fact, that was one of the original issues that led to the issuance of Generic Letter 97-04 that licensees were crediting this pressure without prior Staff review and approval.

NRR also publishes the extended power uprate Staff review Guidance Document will be revised at a later date, and practically we couldn't put the new revision in until it's gone through the whole process and is a final accepted document.

Accountable license power reactors crediting containment accident pressure is 25. Of these, 16 BWRs all Mark I containments, and none PWRs, of which five are subatmospheric. The subatmospheric containment PWRs have always credited containment accident pressure for NPSH during the injection phase of the design-basis LOCA.

And to help put this issue into perspective, it should be noted that licensing analyses other than those for available NPSH credit containment accident pressure, prime example being reflooding the core of a PWR following a large break LOCA, discredits containment accident pressure. The containment accident pressure, like that for NPSH, is conservatively minimized, and this is required by Part 50, Appendix K. Without this credit, the peak cladding temperature criteria in the 2200 degrees Fahrenheit would be exceeded in many cases.

So far I've discussed what we've done and are proposing to do, and I'd like to go into the reassessment and the basis for crediting containment accident pressure.

CHAIRMAN WALLIS: It sounds a bit funny because first it says -- there's a statement that says you can't take credit, you've got to assume it's the original pressure. That seems to be there. And then there's another statement down below which says, ah, but you can use a conservative analysis. They seem to be conflicting statements. Rather than saying you can do 1, 2 or 3, they seem to be two conflicting pieces of guidance.

MR. LOBEL: Yeah, that comment has been made internally, too, and I think it's going to have to be fixed.

CHAIRMAN WALLIS: RANSOM: You can't do

it, and then it says how to do it, it doesn't make sense.

MR. LOBEL: It's a leftover from the reluctance to do it.

CHAIRMAN WALLIS: Are you going to fix that?

MR. LOBEL: Yes.

CHAIRMAN WALLIS: Well, I know it wasn't clear in that section what they were referring to, whether that second statement referred to a comment you made in a previous paragraph -- it's confusing, in any event.

MR. LOBEL: That will get fixed. Like I say, that comment was --

CHAIRMAN WALLIS: We're not reviewing the final document?

MR. LOBEL: The five factors I talked about briefly before -- the integrity of the containment, the conservatism in the calculations, the fact that the ECCS in containment spray pumps are of a robust construction and made of a cavitation resistant material, the fact that the emergency operating procedures aren't significantly altered by dependence on containment pressure, and that the risk calculations show an insignificant increase in risk due to reliance on containment pressure --

CHAIRMAN WALLIS: Well, the risk of having an impaired containment integrity is so low you don't worry about it -- because, obviously, if you lose containment pressure, you lose this stuff you're trying to credit.

MR. LOBEL: Marty's going to talk about that. He's done a pretty careful analysis that he's going to present.

CHAIRMAN WALLIS: Very small numbers.

MR. LOBEL: The first rationale -- one rationale for not crediting containment accident pressure, like I said, was impaired containment integrity. Design-basis analyses assume containment integrity. This is acceptable since the containment is subject to tests which verify its integrity. A structural test is performed prior to licensing. 10 CFR 50 Appendix J requires periodic leakage testing of the containment. 10 CFR 50.55(a) requires periodic inservice examination of the containment structure according to the ASME code.

Like I showed before, a majority of the containments crediting containment accident pressure are BWR Mark I containments. These containments are inerted during operation with nitrogen gas. Inerting is required by regulation and by their plant's tech specs. Any significant increase in the amount of nitrogen that has to be added to the containment might be a sign of degradation in a containment integrity and would be observed by the operators, and the operators would then take action in accordance with the plant's abnormal operating procedures.

The second largest group of containments crediting containment accident pressure are the subatmospheric containments, and of course for the PWRs with subatmospheric containments, the containment integrity would also be continuously monitored by maintaining the vacuum, and the technical specifications require a shutdown within one hour if the vacuum is lost.

Another assurance is the walkdown that's done to check valve alignments and the configuration of a containment that's conducted prior to and during the startup of a plant from an outage.

Since available NPSH is being calculated for design-basis accident, the analysis is conservative. The calculations are done with assumptions that minimize the available NPSH and maximize the required NPSH.

There's a concern when performing design-basis analysis that the results should not be skewed to the extent that they become misleading, and it's become apparent during this reassessment that this is at least a possibility in this case, that perhaps the analyses at least in some cases are done with a degree of conservatism that skews the result to conclude that containment accident pressure is needed when a more realistic, but still conservative analysis might not reach that conclusion.

CHAIRMAN WALLIS: Is this something like the temperature of the water is too high, or something?

MR. LOBEL: Right.

CHAIRMAN WALLIS: Because I don't know what else is conservative. The pump is just pumping water from one place to another, and I don't know what you're conservative about if you're not crediting pressure.

MR. LOBEL: The pump is pumping, but the required NPSH increases as the flow of the pump increases, and part of the analysis biases the calculation so that that pump is going to be pumping more -- for instance, in the first ten minutes of the accident, there isn't any credit for operation action. So the operator doesn't throttle the pump for the first ten minutes, and the pump is operating at runout for the first ten minutes. So the pump is pumping all it can pump for the first ten minutes. In talking to some operators about what would really happen, their consensus is pretty much that that could be -- that the pump could be throttled within two to three minutes. So, there's conservatism in that.

There's conservatism in the flow that's assumed. The flow that's assumed in the NPSH analysis is greater than the flow that's assumed in the ECCS analysis. So, actually, there's a conservatism in the flow that's assumed. A higher flow is assumed, and that gives you a higher required NPSH.

And then in terms of temperature, there's a lot of assumptions that are made to increase the temperature of the water.

CHAIRMAN WALLIS: Are all these conservatisms carried on when you're doing the realistic analysis which is mentioned later on?

MR. LOBEL: No.

CHAIRMAN WALLIS: I wasn't quite sure what you're being realistic about. I'm getting ahead of your presentation, but --

MR. LOBEL: For instance, if I were doing a conservative analysis, I would assume the reactor was at 102 percent. For a realistic analysis, I'd assume it was at 100 percent power. For a realistic analysis, I might assume that the nuclear conditions in the reactor are whatever they are. For a conservative analysis, I'll assume that the reactor is operated for a very long time --

CHAIRMAN WALLIS: Okay. So you're allowing in the guide a conservative treatment of pressure in the containment.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: And you seem to be saying you're allowing a realistic treatment of everything, not just how the pressure gets in the containment.

MR. LOBEL: It's a conservative treatment.

CHAIRMAN WALLIS: Well, but you're also allowing alternative which is realistic. Are we going to talk about that later on -- how much you're being realistic about in the alternative realistic treatment. Maybe I wasn't clear there. You're going to tell us that later?

MR. LOBEL: Yes.

MEMBER RANSOM: One area that seems weak in the conservative analysis is the loss across the debris beds, which is an unresolved safety issue, and

I don't know that there's great confidence in the ability -- except some plants that I guess had changed insulation and things like that -- what that value would be.

MR. LOBEL: Well, for the BWRs, it's a resolved issue, unless it needs to be raised again -- if we find something from the work that's being done on the PWRs that requires us to go back to the BWRs, the issue has been resolved for the BWRs. And for the PWRs -- Ralph, do you want to -- I can -- for the PWRs, my understanding is -- and Ralph can correct me -- they are operating under JCOs now, and you're right, the issue isn't resolved for the PWRs.

MR. ARCHITZEL: Just a point or comment, I won't go into much, ACRS is well aware we're working on that issue. Ralph Architzel, from NRR, Plant Systems.

We do have a position that was approved, though, in the guidance, about using containment overpressure in the Alternate Analysis section. But other than that, it was using the Reg Guide as it was in Rev 3. So, containment -- whatever licensing basis for containment overpressure existed, they were allowed to use containment overpressure with the Alternate Analysis section, Section ;6 analysis, and then I guess the Staff position, maybe, but we did distinguish that way.

MEMBER RANSOM: Is that -- I guess they have enlarged the sump screens and that's part of the --

MR. LOBEL: They are in the process of doing that, and we are in the process of doing reviews of their proposals right now, for the PWRs.

MEMBER POWERS: I want to go back to your previous slide, at least conceptually, I don't know that you need to dial it -- but you go through, and you discuss that, indeed, the Mark I is inerted and that you would presumably on startup detect that you cannot maintain inertion without some reasonable flow. Did the Fitzpatrick event cause you any pause in that confidence?

MR. LOBEL: Well, the Fitzpatrick event was under water, yes, so it wouldn't have identified that as a problem. You're right. It's not 100 percent. The Fitzpatrick event -- and I don't know all the details, but the Fitzpatrick event is probably more of a concern for structural capability, I would imagine, than loss of water.

MEMBER POWERS: You lose enough water, and you're going to lose gas, too, and if it happens during your accident, when you're going to put the maximum stress on that, then you're got a problem.

MR. LOBEL: Yes. And that's a concern. I can't speak to what's being done now about Fitzpatrick. I don't know what the Staff is doing in that area. But, yes, you're right.

Okay. Well, I guess the point is that -- the concern is that we may have done -- the industry may have done these calculations with such a degree of conservatism that maybe we're talking about something that really isn't a problem --

CHAIRMAN WALLIS: We don't know, and if they've done the calculations and we have the results, then we could see if your statement is true. Just as a "maybe", I don't think it adds very much.

MR. LOBEL: Well, we have some sensitivity analyses, we don't have a complete realistic analysis -- I take that back. We do have a realistic analysis done by the licensee, which shows that there's no need to take credit for containment pressure. We have sensitivity studies that have been done where different parts of the analysis were set to a realistic value, and that indicates that it's not necessary to take credit for containment accident pressure.

So, I think we have some pretty good indications that --

CHAIRMAN WALLIS: Well, it's more than a "maybe", we actually have an analysis behind it, and results.

MR. LOBEL: Yes. We don't have what you were asking for at the subcommittee meeting, we don't have sensitivity studies that rank all these conservatisms.

CHAIRMAN WALLIS: I thought you promised to give them to us.

MR. LOBEL: Well, we're talking about doing it. I think I said at the time -- if I didn't, I apologize -- that it's not an easy thing to do in a month, but we are still looking at ways to do that.

I do have some references that I can give you --

CHAIRMAN WALLIS: Is it going out for public comment?

MR. LOBEL: Yes.

CHAIRMAN WALLIS: By the end of the comment period, you will have perhaps some harder results to talk about?

MR. LOBEL: We will have results to talk about before then. I'll make a commitment to come see you and tell you where we are.

The only other point I wanted to make was that this situation isn't unique in the regulatory analyses either, that statistical LOCA and statistical DNBR calculations allow uncertainty to be treated in a less bounding way, but still conservative so that the results aren't overly unrealistic. And in that case, you're not putting an excessive penalty on core designers when it's not necessary.

I have a list of the -- of some of the conservatisms that go into these calculations for PWRs and BWRs. I wasn't intending to go through it. I did go through the BWRs at the subcommittee meeting, but in view of the time restraints here, I wasn't planning to do that. But these -- the ones that are listed are typical of those that are used for PWR and BWR analyses. They may not all be used in each analysis, but typically most of them are.

CHAIRMAN WALLIS: The one which my colleague already referred to which was "iffy" is this calculation of debris head loss is bounding. It means you assume that whatever it's called, the thin effect and all the worst things that could possibly happen, then you calculate the head loss across the screen?

MR. LOBEL: Yes. The head loss that's

included in the calculations is meant to --

CHAIRMAN WALLIS: The worst you could possibly calculate?

MR. LOBEL: I'm sorry?

CHAIRMAN WALLIS: It's the worst you could calculate, isn't it? You assume the debris is distributed in the worst possible way across the screen.

MR. LOBEL: For the BWRs, it's my understanding that it's done uniformly. For the PWRs, I think that's still an issue being decided.

CHAIRMAN WALLIS: What is bounding may be still up in the air.

MR. LOBEL: For the PWRs, yes.

CHAIRMAN WALLIS: The one data point given by some research program that's higher than all the others has taken the bounding value --

MR. LOBEL: I'm not prepared to talk to that.

CHAIRMAN WALLIS: It's up in the air, it seems to me, still.

MR. LOBEL: Yes. One key point to keep in mind with conservatism also is that all these conservative assumptions are assumed to occur simultaneously in the analysis. The worst pipe break is chosen in terms of it's adverse effect on NPSH conditions, and at the same time the parameters specified in the technical specifications --

CHAIRMAN WALLIS: Do you have numbers on these slides?

MR. LOBEL: No.

CHAIRMAN WALLIS: You lose points for that.

MR. LOBEL: I tried. I tried. I called our Help Desk. I talked to the people who knew this, and nobody knew how to put numbers on here. So, I apologize. This isn't PowerPoint, this is Corel.

CHAIRMAN WALLIS: Oh, it's something weird. Okay.

MEMBER POWERS: It's easier to use than PowerPoint.

(Simultaneous discussion.)

MR. LOBEL: Anyway, the point is just that all these assumptions not only are conservative but are made simultaneously. The pipe break, the values in the technical specifications are at the limiting values, the worst single failure occurs, and every physical process takes place in its most limiting way, and that adds confidence to the analysis that it may be leading us in a direction we don't need to go.

And when I talk about this -- this is just an observation now, this hasn't been factored into any reviews, the reviews are still all done making all these conservative assumptions. I'll move along.

CHAIRMAN WALLIS: Everything in your presentation is about conservatism, not about the realistic calculation --

MR. LOBEL: There is --

CHAIRMAN WALLIS: -- which is also allowed.

MR. LOBEL: Nobody has proposed that yet. We've talked to some people --

CHAIRMAN WALLIS: But it's in the Reg Guide, isn't it?

MR. LOBEL: It was put in the Reg Guide as something that would be available. It's in the Reg Guide as a very generalized statement because nobody has tried this yet and it isn't very well defined, but the idea is that it would be used pretty much the same way that the calculations are done for best estimate LOCA --

CHAIRMAN WALLIS: Well, it says "95-95", it doesn't say about what. Is it about the pressure in the containment, or the temperature in the pool, or NPSH?

MR. LOBEL: It would be in terms -- well, the thinking was it would be in terms of the margin, NPSH margin.

CHAIRMAN WALLIS: If it's NPSH including pressure drop across the screen, it's different from if it's NPSH not including pressure drop across the screen. So, somebody has got to figure out what you really mean by this 95-95.

MR. LOBEL: And the idea was to put it in as a very general statement --

CHAIRMAN WALLIS: I understand that. I understand that.

MR. LOBEL: -- and then hopefully somebody will attempt to use it or at some time will try to --

CHAIRMAN WALLIS: Well, I guess I'm thinking that maybe when it comes back from public comment, you may want to be a bit more specific about what it is that's being calculated with this 95 percent confidence, does it include the pressure drop across the screen, or just the NPSH that you define without including the pressure drop and things like that.

MR. LOBEL: Okay.

MEMBER RANSOM: You may have said it before, but do these same considerations apply to EPU?

Would you apply it?

MR. LOBEL: Yes.

MEMBER RANSOM: The element of necessity doesn't seem to be present in that case. I can understand the existing plants and utilization of this methodology for those, but in an EPU you'd think, well, put in new equipment or whatever you need to do. It's just an economic issue.

MR. LOBEL: And it was that kind of inconsistency that we're trying to avoid by changing the position and talking just in terms of safety and not in terms of necessity or that kind of thing.

MEMBER RANSOM: Which would permit an extended uprate to use the same methodology than if they could --

MR. LOBEL: Because necessity isn't well defined, it never should have been in in the first place. I guess the idea was to think more in terms of the possibility of making these changes, but as we talked with licensees and people with the NRC with experience, plant experience, it wasn't a very practical --

MEMBER RANSOM: Well, the thing that is confusing in a way, if you were to design a new plant, you probably wouldn't want to use this kind of methodology, you'd simply put in pumps that have a low enough NPSH requirement to not need it.

MR. LOBEL: Well, in fact, that's what's done. If you look at the plants that I was talking about that are using this, the older Mark Is, and the subatmospheric containments because they have the problem -- they are starting at a disadvantage with their subatmospheric value for the pressure -- and if you assume that subatmospheric value is the value for the whole NPSH analysis, they need the containment pressure. But the later Mark I containments, the Mark II and Mark III BWR containments, don't take credit for containment accident pressure for just the reason you say, because they've put in better pumps and they've done a better design, but primarily it's the pumps.

There's a slide that I showed at the subcommittee meeting that I didn't put in here, that was a chronology of licensing of BWRs with the required NPSH, and for the very old BWRs the values were around 27 to 30 for the required NPSH, and for the newer plants it's down around 2 to 4. So they have improved this so that it's not a problem, but Mark II and Mark III containments won't need credit for containment accident pressure. In fact, their pumps can operate with saturated fluid -- in pump saturated fluid.

MEMBER RANSOM: The concern would be about new plants then, which, admittedly, they wouldn't need it if they designed them properly.

MR. LOBEL: Well, hopefully the Staff reviewers wouldn't accept this type of thing with a new plant now. I mean, knowing what we know now, if somebody came in with a new design and requested containment accident pressure for NPSH, I think we'd tell them to go redesign or pick another pump.

CHAIRMAN WALLIS: Something I don't understand here, you've come ahead to pump design, but in the PWR conservatism, it says: "The pressure of the containment atmosphere is equal to the vapor pressure of the sump water or the sump water temperature", then you don't have any overpressure.

MR. LOBEL: Right.

CHAIRMAN WALLIS: So, how can you take credit for something you've already assumed isn't there?

MR. LOBEL: That's a conservatism because --

CHAIRMAN WALLIS: It makes no sense.

MR. LOBEL: That's a conservatism that was put in the standard review plan a long time ago, and the thinking is that -- if you remember the available NPSH appraisal, there's a minus-vapor pressure --

CHAIRMAN WALLIS: But the temperature is less than 100 degrees Centigrade, it's subatmospheric containment, that's the pressure in the containment. If that's the pressure the pump sees, it's already going to cavitate because it's going to boil the water at the pressure -- it's already at the boiling point, so it doesn't make any sense.

MR. LOBEL: Well, the pressure is --

CHAIRMAN WALLIS: It's for the head, the gravitational head, I guess.

MR. LOBEL: The pressure is high enough that even at a conservatively calculated temperature, the water is still subpooled in the sump. But what this is doing is, if you remember the equation for available NPSH, there's a term for pressure and then there's a term for minus the vapor pressure. So, if I set that pressure equal to the vapor pressure, those two terms cancel, and the only term that I have that's positive that's contributing to the NPSH is the elevation of the water within tech pump suction.

CHAIRMAN WALLIS: So, how can you take credit for any kind of containment pressure with this statement?

MR. LOBEL: You're not, it's just an assumption.

CHAIRMAN WALLIS: But you've assumed away the thing you want to get credit for, you see my problem with this thing?

MR. LOBEL: Yes, I see your problem. Maybe it shouldn't have been included in the list, but --

CHAIRMAN WALLIS: It makes no sense.

MR. LOBEL: Well, it's an -- again, it's an artificial thing that was done --

CHAIRMAN WALLIS: It makes no sense because you're trying to get credit for -- isn't this something to do with allowing credit for pressure in the containment?

MR. LOBEL: But in this case, you're setting the pressure equal to the vapor pressure just artificially, so the temperature isn't a consideration --

CHAIRMAN WALLIS: How can you get credit for something, though -- credit by the pressure created by the LOCA in the containment being higher than the vapor pressure of the sump water, that's the whole basis of it.

MR. LOBEL: This assumption isn't doing that. This assumption is an alternate way of doing the calculation.

CHAIRMAN WALLIS: It's an alternate way of doing it.

MR. LOBEL: And the alternate way of doing the calculation is done presumably --

CHAIRMAN WALLIS: This, again, goes back to what we had said earlier. You've got sort of three different ways of doing it, but they are sort of mutually exclusive, and you're going to sort that out. It's very confusing.

MR. LOBEL: Well, I can explain it. Unfortunately, I don't have a slide with the equation on it, but --

CHAIRMAN WALLIS: No, but you understand what I mean.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: You've got this statement which sort of negates any kind of credit for any kind of overpressure.

MR. LOBEL: That's the idea. That's what this is meant to do.

CHAIRMAN WALLIS: The whole discussion today is about how to allow credit for overpressure.

MR. LOBEL: Well, maybe I shouldn't have included that. Obviously, I shouldn't have included that.

CHAIRMAN WALLIS: But it's in the Guide.

MR. LOBEL: It's in the Standard Review Plan now, it's not something we're adding, and it's meant to be a conservative way of doing the calculation.

CHAIRMAN WALLIS: That's your position, then you're not allowing any overpressure, correct?

MR. LOBEL: Right.

CHAIRMAN WALLIS: But that's not your position, is it? You are allowing overpressure.

MR. LOBEL: If the licensee chooses that way of doing the calculation, that's an acceptable way --

CHAIRMAN WALLIS: This is an alternative way.

MR. LOBEL: It's an alternative, right.

CHAIRMAN WALLIS: But the whole discussion today is about --

MR. LOBEL: Well, I shouldn't have put that in my list.

MEMBER BONACA: Now, you say that for a new plant you will not allow these considerations.

Why?

MR. LOBEL: Well, because there wouldn't be any use to.

MEMBER BONACA: I mean, if you're making a case for safety, it should be applicable to anyone. I mean, I'm trying to understand. Why would you relax this requirement which has to do with safety, but you consider them important enough that you will not relax them for a new design.

MR. LOBEL: I just -- this is something that -- it's hard to answer that question without using the word "necessary". It's something that we give credit for because in cases of older plants they can demonstrate that they have this pressure and we're trying to make the argument why we think that's okay, but for a new plant starting from scratch, it just doesn't seem to be something that --

MEMBER BONACA: I understand. I mean, I understand the --

MR. LOBEL: I suppose if a licensee came in and said "here's our reactor design and there's no other way around it", then it would be something that would have to be reviewed, but I would think designing a new plant you could work your way around it.

MEMBER BONACA: Of course you could. Of

course you could, and you should, but I guess I'm following after the conversation with my colleague here. If you are operating a plant, it's a new plant -- I mean --

MR. LOBEL: Well, it is and it isn't.

MEMBER BONACA: I mean, you're making a case for -- a safe case, you're saying that there is sufficient margin here in these assumptions which are all over the -- by the way, these aren't the same assumptions that are always behind the licensing of this plant. So, I mean, if you're saying there is sufficient margin there that can justify some backpressure, so you're making a safety case. But then you're saying that it's not very good because for a new plant I will not allow it, so it's somewhat conflicting as a statement, unless you introduce the issue of necessity, and for necessity I can see it on a grandfathering way if you had to -- but if you have some certain actions where you're gaining from -- I mean, just the issue of necessity becomes confusing.

MR. LOBEL: Well, when I was going through the history, I was trying to show that usually this ended up being an issue when something else new came along for an existing plant that the plant could easily meet without -- I shouldn't say "easily" --

would have been not practicable for a plant to meet without taking credit for containment pressure.

Most of the new plants, in my understanding, are passive anyway, and --

MEMBER BONACA: You will still expect, if the case is made for a power uprate, that you would demonstrate how some of these conservatisms can be traded in or tradeoff for NPSH. I mean, it's not simply that you make a list of conservatisms and say, "I have all these conservatisms, so I can do what I want" -- I mean, you will have the calculations to show how you are using them.

MR. LOBEL: Oh, yes. These conservatisms would be used in the calculation.

MEMBER BONACA: And so you would have the most pressure and you would demonstrate how much of this margin is still maintained.

MR. LOBEL: They would do a -- the applicant or the power operator or whatever would do a calculation, an NPSH calculation. They would calculate the containment condition using the conservatisms that are relevant to that, and then they would do the sump calculations and the loss calculations and all those calculations together would go into the NPSH calculation.

MEMBER BONACA: And you would have to feel comfortable that it would maintain sufficient margin for all the other things for which this margin was built in. I mean, this margin was built in based on many different analogies, calculations, concerns, initiators, and --

MR. LOBEL: That's true for some of them, but some of them were specific -- the 102 percent obviously isn't there for NPSH.

MEMBER BONACA: So this is a general list of conservatisms which you would draw upon for --

MR. LOBEL: Right. But the point is the 102 percent is there to account for instrument uncertainty and the bounding of the uncertainty, but it is used in the NPSH calculation. It is included in that calculation. It's one of the conservatisms in that calculation as well as the LOCA calculation and transient calculations.

MEMBER RANSOM: I guess continuing with that argument a little bit, when you read the history of this issue, it seems like this credit has been granted on an ad hoc basis and somewhat dependent on maybe the reviewer or the opinions of the people. And in a way, without something more definitive, I guess, as far as future plants are concerned, or power uprates, you would expect people to take advantage of this if it benefits them, I guess.

MR. LOBEL: Well, if it benefits them, meaning that they need that credit for containment pressure, or they have to do something to the plant that may be very impractical to do --

MEMBER RANSOM: Even for a new plant?

MR. LOBEL: No, not for a new plant, that's what I'm saying. For a new plant -- I still think for a new plant -- I'm just speaking for myself. If I were the reviewer, I would expect a new plant not to have to take credit for containment pressure, I would expect them to be able to design the plant so they don't have to.

MEMBER RANSOM: Well, you'd expect, but that doesn't mean they have to.

MR. LOBEL: It doesn't mean they have to, and if they did, that would be a subject of the review.

MEMBER RANSOM: Even the extended power uprate, you know, there I would think the argument of necessity is just simply an economic matter of trading off new pumps versus not doing it, not uprating the plant.

MR. LOBEL: And we decided that it was

better -- more appropriate to have the position that if it's safe, it's acceptable, rather than get into discussions of now economical it is to replace a pump, and leave that decision to the licensee.

MEMBER RANSOM: Well, when you say safe enough, it would seem like that maybe implies that they should do a complete risk analysis and show that the risk is no greater than operating the plant the way it is.

MR. LOBEL: Well, can we leave that for the risk discussion, or do you want to answer it now?

MR. STUTZKE: Well, I guess the way to look at it is if they chose to submit a risk analysis, we would welcome that, but there is, in fact, no requirement. We don't have a PRA rule, so we can't demand that the licensee do a risk analysis without going all the way up to the Commission and getting approval in accordance with the Standard Review Plan, Chapter 19, Appendix D. So, we need these sorts of rules, these sorts of guidance, I think, that Rick is talking about, to let us make a decision on a deterministic basis alone. Did I say that right?

MS. RUBIN: It sounded pretty good to me. Mark Rubin, from the Staff. Of course, today the risk assessment, the scoping or sort of the perspective look that Marty took would identify deterministic elements that would be important to preserve during the deterministic review -- containment integrity, things of that nature -- and so the insights are certainly useful for the deterministic review, but the work done shows that the risk impact beyond design-basis is very, very small. I mean, we're near the threshold for the Staff to force the licensee individually to do risk evaluations. Though we certainly would welcome them if they wanted to come in with a risk-informed submittal in this area, they are not required to do so by Commission policy or the regulations.

CHAIRMAN WALLIS: Isn't this a compliance issue? What's risk have to got with it? The pumps are supposed to work.

MR. LOBEL: Well, yes, it is a compliance issue. It's a deterministic issue, that the calculations that are done by licensees are done deterministically and that these types of conservatisms that we've been talking about to ensure that they're not going to underestimate the available NPSH or underestimate the required NPSH, and that's the analysis that's reviewed. For a recent review, we have gotten into the risk arena more, in part to look at the weight of these concerns. We wanted to get an idea of just how conservative these calculations are, and looking at the risk aspect was one part of doing that. But the review is a deterministic review, and we look to see that there's adequate NPSH with a conservative analysis or adequate NPSH margin.

MEMBER RANSOM: Don't they have to, under Reg Guide 1.174, at least show that what changes you are making to the plant result in minuscule or very small risk increase?

MR. STUTZKE: Yes, but the use of Reg Guide 1.174 is voluntary on the part of the licensee. That's what it means to submit a risk-informed license amendment request. They don't need to do that.

MS. RUBIN: Right. Mark Rubin, again. Traditionally, a licensee will use a risk-informed approach where perhaps the deterministic basis is not quite as strong as the traditional engineering reviewers would like, and that the risk evaluation provides a lot of additional emphasis and basis for the adequacy of the change. But, again, as Mr. Stutzke pointed out, it's a voluntary approach, and if all the deterministic requirements are met, all the regulations are met, a licensee is to required to use a risk evaluation risk-informed approach.

Now, the Staff does have the authority to severe accident beyond design-basis risk impact where we believe it reaches a high threshold of potential beyond design-basis risk or vulnerability, and the Commission was very strict in the ability that we had to do that, and it's laid out in an office instruction. It's laid out in Appendix to SRP 19, and then that came down from the Commission paper laying it out, and basically it goes into the area where all the regulations are met, so there's a presumption of adequate protection, but because the original regulatory requirements didn't treat or consider a potential severe accident vulnerability that now we have become aware of, the staff can pursue severe accident issues. In this case, Marty's looked at it, and we appear to come nowhere near the threshold where the Staff could pursue an accurate protection determination.

VICE CHAIR SHACK: But isn't it a fact that most people who have submitted the EPUs also choose to submit some risk information -- they don't have to, but they do.

MS. RUBIN: The power uprates is one of the examples given in Appendix D where the Staff would want to see risk evaluations because of -- you may recall an issue called synergism, synergistic effects, where a power uprate could propagate throughout the plant timing issues, change the success criteria. At that time, we didn't have much experience in the large power uprates, and because of potential to propagate synergistically through the entire plant this assessed criteria of many beyond design-basis accident sequences, we identified that as one of the cases to the Commission where the Staff would pursue risk, but it is voluntary when it comes in on the power uprates, and if, in fact, any licensees chose not to, the Staff would have the burden to prove where our concern on adequate protection arose before we could force them to provide supplemental risk information, but to date the industry has been very cooperative in this area. I think they recognize the importance of looking at in the power uprate arena.

MR. LOBEL: I think I'm taking too much time, there's other speakers, too, so let me try to go through this a little faster.

On pump design, I think the point is just that these pumps are robust construction, mechanical steel, stainless steel impellers. Stainless steel is resistent to erosion from cavitation. There is a quantity called suction energy. The suction energy for these pumps --

MEMBER RANSOM: Is that just the kinetic energy of the fluid, or is it more complicated?

MR. LOBEL: It's a term the industry uses. It really isn't a physics term so much as -- I think it's more empirical.

MEMBER RANSOM: I've heard terms like "thermodynamic head" used when you're pumping hydrogen and stuff like that.

MR. LOBEL: It's not a thermodynamic quantity, it's the speed of the pump times the quantity called the suction specific speed times the diameter of the impeller eye, I think --

MEMBER RANSOM: It's an empirical --

MR. LOBEL: Yes, it's an empirical quantity, I believe, and the Hydraulics Institute developed curves of -- based on this quantity of how susceptible a pump would be to cavitation damage, which is also empirical based on data from pumps of different sizes and designs. So, it's not something -- it's not thermodynamic quantity or hydraulic quantity.

The Staff has given credit for pumps operating in cavitation with or without credit also for containment accident pressure, and this is based on cavitation test by the pump vendor or by the utility. This is a list of some of the tests that have been done. Typically, the tests have been one hour or less. Quad Cities did some tests on an RHR pump where they tested the pump for an hour, took it apart and looked at it, put it back together, tested it for another hour, took it apart again, inspected it, no damage, put it together --

CHAIRMAN WALLIS: What does this mean in terms of regulation? Does this mean that Vermont Yankee would be allowed to operate their pumps with something less than -- up to 3 percent less than the NPSH?

MR. LOBEL: They proposed that, and that's still being reviewed.

CHAIRMAN WALLIS: So, it's somebody's judgment now about whether that's okay or not?

MR. LOBEL: Well, some of these other cases are also less than -- 3 percent is the typical required NPSH definition. So, in these cases when I talk about pump speed in cavitation, typically that is below the 3 percent required -- 3 percent head drop that's in the definition of required NPSH.

MEMBER RANSOM: Is this discussion mainly to indicate there is added margin because you can operate the pump without damage?

MR. LOBEL: Yes, that's all.

CHAIRMAN WALLIS: It's not to say that you would allow them?

MR. LOBEL: We have allowed credit in some cases. The Vermont Yankee case, I was going to mention, is different than some of the others because in the case of Vermont Yankee their testing wasn't on a specific pump for a specific length of time. Their basis is more on the judgment of -- technical expertise and judgment of the pump vendor based on tests on Vermont Yankee pumps and pumps similar to the Vermont Yankee pumps.

CHAIRMAN WALLIS: Presumably it's still pumping okay, still pumping the same flow into the same pressure?

MR. LOBEL: Right.

CHAIRMAN WALLIS: And all you're concerned about is damage.

MR. LOBEL: Right. As long as there's adequate NPSH --

CHAIRMAN WALLIS: So this is sort of performance-based as long as it's pumping the water and supplying enough pressure?

MR. LOBEL: Right.

CHAIRMAN WALLIS: So maybe they could do a test that says it can be less than 10 percent NPSH, come back and say, "Well, we've shown that the pump still works, now we want to have credit for that", would that be acceptable?

MR. LOBEL: Nobody has asked for that yet.

CHAIRMAN WALLIS: But you don't know yet.

MR. LOBEL: We don't know.

CHAIRMAN WALLIS: Still seems a lot of what you had before, negotiable things in this NPSH are still there.

MR. LOBEL: There aren't hard and fast criteria on what's acceptable and what isn't acceptable. What's in the Reg Guide now is kind of what was done for Beaver Valley and Quad Cities, and Browns Ferry to some extent, where the pumps were tested for a given length of time at a given level of cavitation for a specific pump, and what Vermont Yankee is proposing is something different than that, and that's still being reviewed.

CHAIRMAN WALLIS: So that's one of the things we're going to hear about?

MR. LOBEL: I'm sure you will. We had a discussion -- I don't mean this to be a Vermont Yankee discussion, but we had a discussion with the State earlier this week, talking about just that issue.

MEMBER RANSOM: Out of curiosity, you talk about this as margin, and there's a design aspect that you were not design to operate in a deep cavitation mode, but if you were in an accident, the operators -- are they told to shut the pump off if -- or would you continue to run it and hope for the best?

MR. LOBEL: The operators -- well, I suppose it depended on what kind of accident it was and where you were. I mean, if it was the only thing you had that was still putting water in the core --

MEMBER RANSOM: You're going to run it, right?

MR. LOBEL: But there are things the operator can do to alleviate the situation. He can turn off pumps, he can throttle pumps. I had a Vu-graph that's in what I presented for the subcommittee, of the effect of throttling the pump, and it has a very significant effect.

MEMBER RANSOM: What I was getting at, if the pumps actually will operate in those modes, you're clearly going to go ahead and operate them, and so there is a certain amount of margin associated with that.

MR. LOBEL: I wouldn't think an operator

would purposely do it if he knew the pump was cavitating and that wasn't absolutely necessary to keep the core covered -- and the operator has -- in the BWR EOPs, there are curves of suppression pool temperature and pump flow with pressure, containment pressure as a parameter, that the operator can use as an indication of whether he has acceptable NPSH, available NPSH.

MEMBER RANSOM: In fact, most pump manufactures say operating down in that mode, there's less cavitation damage than there is between the 3 percent and the 1 percent because you're pumping mostly vapor.

MEMBER RANSOM: I looked into that in some detail as part of the reassessment, and that's a true statement. And there are people who say you should have an enormous amount of margin, which is impractical in most cases, and other people that say no margin is okay, that available equal the required is okay, that actually, like you were saying, a little bit more is actually worse because of a distribution and size of the voids in the pump, in the impeller. So, there isn't one unanimous view, but I think it's an issue that certainly could use more research by the pump industry, from what I've seen.

CHAIRMAN WALLIS: Why does all this impact the statement you're going to put in the Guide. We're talking about revisions to the Guide which simply says you can take credit for this pressure as long as you calculate it conservatively, isn't that what it says?

MR. LOBEL: Yes.

CHAIRMAN WALLIS: And it says in a way which is somewhat vague, if you don't want to calculate it conservatively, you can do it realistically and figure out some 95-95 limit of something, doesn't really say what. That's what's in the guide. Why are we talking about all these other things, we should just concentrate on just two things, shouldn't we?

MR. LOBEL: Well, as part of revising the Reg Guide, we went back and tried to do a reassessment of the whole issue, and what I'm presenting -- maybe I'm presenting too much, but what I'm presenting is the results of that reassessment. We didn't want to just change the words without going back and looking at what we've approved in the past, and the basis for it.

The next part of the discussion is risk. Let me just say that in light of what ACRS has asked for before in terms of looking at other events besides

LOCA, I've put in two tables of other transients and events that are considered, or they are likely to impact NPSH, and discussed them in the table in terms of temperature and debris, whether they generate debris and whether they generate high temperatures. So, the likelihood that you'd need pressure credit for those events and, for the BWR, depending on the design, there's several LOCAs limiting. For the PWR, the LOCA is typically the only event that requires recirculation, and all the other events can pretty much be handled from water from the TWST, so you don't get into this issue. That's all I have.

MR. STUTZKE: Okay. So let's talk a little bit about the risk evaluations that I've done. In an effort to get my arms around this problem, I did some research into previous PRAs and PRA development guidance, to try to understand better, and specifically I had to go all the way back to WASH-1400. I looked at some of the summaries of the IPEs and the ASME PRA Standard and the RASP Handbook. The RASP is the guidance for development of the Staff's SPAR models. Next slide.

(Slide)

I actually found in the WASH-1400 BWR event tree that considered leaking containments following a LOCA, and specifically they had a criteria that said if the leakage rate is bigger than 100 percent per day and the long-term cooling fails, the suppression pool cooling, then it was presumed the ECCS pumps would cavitate. That 100 percent per day -- not double zero 100 percent -- there's a statement there, that's equivalent to a one-inch hole in the side of the containment. There are different probabilities of loss of NPSH in this scenario, depending on the size of the LOCA and the location of the break inside the containment, whether it's in the drywell or the wetwell. So, it's a little confusing as to why there are different probabilities there, but the effect that we're after, the fact that the containment could, in fact, be depressurized and lead to a loss of NPSH was captured in WASH-1400 some 30 years ago. Next slide.

(Slide)

What you are looking at here are summaries of IPE results. This is in NUREG-1560. Specifically, there's total core damage frequency. When the Staff made this report, they defined a category called "Loss of decay heat removal", which includes things like suppression pool cooling failures and failures of containment venting. One way to fail the containment venting is the operator doesn't throttle adequately. In other words, he totally depressurizes the containment and it would lead to a loss of net-positive suction head for the ECCS pumps. So when you look at the loss of DHR, realize this is all these sorts of effects in here, it's not just specific to loss of NPSH. You can see for the Mark I containments it could be significant. For the Mark III, IV, V, VI, it's not important. The message here is that, yeah, you can see some effect in here, but the resolution of which this NUREG collected the data is so broad you can't really infer much out of this table. I threw it in here to let you know, in fact, I did try to look. Next we jump to PRA modeling guidance, next table.

(Slide)

I looked at the ASME PRA Standard, and there are in fact supporting requirements that address the need to model failures that lead to loss of NPSH -- AS-B3 concerning phenomenological events, two in systems. You're talking about specifically containment failures effects on system operations. Also, if you go to the RASP Handbook, that is a practical "how to" handbook used to develop the SPAR models. It talks about the necessity of modeling losses of NPSH. So, the guidance exists. We have a

PRA of some 30 years ago were, in fact, this model --

CHAIRMAN WALLIS: It's a 30-year-old PRA?

MR. STUTZKE: Well, the point is -- my bullet No. 3 here is beyond that I have not found a single PRA that actually models loss of NPSH due to failure of the containment overpressure, it just doesn't exist. It doesn't appear to be in any one of the IPEs that were modeled. It's not in any of the Staff's SPAR models.

MEMBER APOSTOLAKIS: You have actually looked at all the PRAs the industry has done?

MR. STUTZKE: No, sir, I've looked at what they talked about, summary of the IPE models in that NUREG, and I did examine the SPAR models. I talked to the developers of the SPAR models. As I say --

MEMBER APOSTOLAKIS: So if somebody had done it, your argument is, what about the --

MR. STUTZKE: I would love to see it if they have done it, I would love to see it.

MEMBER RANSOM: Is the implication here that it's small?

MR. STUTZKE: Well, my calculations -- I did some risk calculations that we'll talk about here in a minute. The implication here is I'm curious why people have not modeled this, given that credit has been taken for containment accident pressure. Why wasn't it being modeled like this? I'll also point out for all of the license amendments so far that are crediting containment overpressure haven't been risk-informed, so we've never asked for the risk information with that.

CHAIRMAN WALLIS: So it's to in the PRA, so to get some number for CDF, we should add in something for this, like the other thing --

MR. STUTZKE: In fact, I can tell you how much to add in. I can give you an idea. Okay. In fact, that's what I set out to do was realizing that previous PRA -- I couldn't find any in the previous PRAs, I decided I would try to estimate what the increase in cord damage frequency would be if I needed the overpressure and in fact it wasn't there at the time. And the first observation along developing this type of model --

CHAIRMAN WALLIS: Tell me what happens if it's not there, do you assume there's no flow from the pump, or what do you assume?

MR. STUTZKE: Well, the first realization is that if you lose the overpressure, you may not immediately generate the loss of NPSH and cavitate to pumps in the flow. In fact, if NPSH loss, the PRA assumes there is zero-flow out of that pump -- in other words, the success criteria has not failed, so it's a conservative because PRA is a binary sort of thing. But the reason why the loss of overpressure doesn't immediately cause failure in the PRA space is the realization that it takes time to heat up the inventory of the suppression pool to get the temperatures you need to create the phenomenon. And to get my hands around this, I made a simple hand calculation. I looked at the water in a BWR Mark I containment -- this is a bucket of water. I said, gee, if I add all the decay heat into heating up that water, how long does it heat up to I think it's about 185 degrees, which is enough to cause the vapor pressure cavitate to pump, this sort of thing. And I got on the order of 4 to 5 hours. Now, I'm a risk analyst, I'm not a thermal-hydraulic analyst, so realize this is a freshman level calculation.

So we then approached a licensee and we said, gee, could you make us a map calculation, give us a real calculation, and they in fact did. They assumed a large recirculation with suction break, MSIV closures, main feed continued running, no credit whatsoever for containment overpressure, so it's like the equipment hatch was wide open in the model. And no suppression pool cooling started at time zero, right at the time of the accident. And they confirmed that four hours is the amount of time it takes to heat up --

CHAIRMAN WALLIS: Remind me about when this recirculation phase starts and when it finishes. When does it start, when do you need the pumps?

MR. STUTZKE: Well, you need the pumps running right at time zero, the ECCS pumps.

CHAIRMAN WALLIS: I'm talking about the recirculation from --

MR. STUTZKE: Remember, I'm talking about the BWRs. I'm talking strictly boilers right now.

CHAIRMAN WALLIS: I'm sorry, I was ahead of you.

MR. LOBEL: The assumption is that at time zero the pumps start and inject, and the operator takes no action until ten minutes. At ten minutes, he continues the injection, but he can start the containment sprays and he can start cooling the suppression pool at ten minutes. So, the cooling of the suppression pool starts at ten minutes, typically with one train of already charged worsening the failure, the failure of one train of already -- so one train is cooling the pool, so you're putting more heat in than you're taking out, and it takes until sometime in the four to eight hour range before the heat exchanger actually starts removing more heat than you generate, and the suppression pool temperature turns around.

CHAIRMAN WALLIS: Well, I guess I'm not sure what to make -- it doesn't really matter when it happens, but what's the consequence when it does happen? Does it matter or does it not matter? If it takes four hours to disaster, or five hours, or ten hours, does it matter? I want to know what's the consequence of reaching this stage -- isn't that what matters? We're taking much too long here. That would seem to be the question to answer. Do we take action during these hours?

MR. STUTZKE: That's right, that's the whole purpose.

CHAIRMAN WALLIS: Okay. Well, I'm sorry.

MR. STUTZKE: We're certain they're not going to sit there for four hours on their thumbs. That's why the hours were important.

(Simultaneous discussion.)

MR. STUTZKE: Most views of human reliability -- I knew you would wake up when we talked about HRH -- we break the assessment of the probability that the operator fails to take action into two phases, the so-called diagnosis phase when he's understanding what has gone on and what he can do about it, and the so-called implementation phase which is when he's actually manipulating controls in the plant to implement his action.

As far as that implementation phase, we talked to licensed operators, and their estimate is the initiating a coolant can be done in very short order following indications of LOCA, and the reasons are it's a very simple task that's done in the control room, they are not running all over the control room or even outside the control room. It's well proceduralized, it's trained, it's simulated training. It's a very expected type of behavior like this.

So, understanding that, I need to understand the probability that they don't diagnose this accident in four hours and do something about it. And in order to get some sort of feeling on this, I went back to the old THERP to --

MEMBER APOSTOLAKIS: This stuff amazes me, Marty. Why didn't you go to ATHEANA?

MR. STUTZKE: Not enough time to wade through.

MEMBER APOSTOLAKIS: Not enough time to do what, to learn ATHEANA?

CHAIRMAN WALLIS: You've got four hours to do it.

MEMBER APOSTOLAKIS: I mean, we're spending so much money developing ATHEANA, and everybody goes back to THERP, ASEP. I mean, you are one of many. It's just that I'm perplexed, as my colleague would say. Is it that ATHEANA is not easy to use?

MR. STUTZKE: I haven't studied ATHEANA for ten years, so I don't know whether it's easy to use or not.

MEMBER APOSTOLAKIS: So, it's been in development for more than ten years, right?

MR. STUTZKE: That's correct.

CHAIRMAN WALLIS: So they won't make a mistake in diagnosis in four hours with a probability of 5E to the minus-?

MR. STUTZKE: 4E to the minus-3. But realize that --

CHAIRMAN WALLIS: What's the data say? I mean, does it tell you why they were confused for most of the day, it seems to me.

MR. STUTZKE: And they failed.

CHAIRMAN WALLIS: Maybe it was two hours, but it was hours anyway.

MR. STUTZKE: And they failed.

CHAIRMAN WALLIS: The confusion was over two hours, wasn't it, something like that?

MR. STUTZKE: I think the best way to look at this diagnosis error, it's roughly 10 times higher than the diagnosis error that's in the baseline SPAR models which is based on the SPAR-H methodology.

MEMBER APOSTOLAKIS: SPAR-H now is more useful? Wow.

MR. STUTZKE: It's the basis for the numbers.

MEMBER APOSTOLAKIS: I know.

CHAIRMAN WALLIS: Moving along.

MR. STUTZKE: Okay. So, in response to the subcommittee's request, I had done a back-of-the-envelope calculation of the increase in core damage frequency. Since that time, I have modified all the SPAR models. I changed all the event trees. I constructed new fault trees, requantified things. The fault tree development included a loss of containment integrity, considered pre-existing leaks and failure of the containment isolation including the MSIVs that Bill Furman had pointed out to me in our last meeting, so I did put those in like that. The data for these comes -- for the pre-existing leaks comes from NUREG-1493, which was issued back in '95, September of 1995, and every interim guidance. Primarily, this is based on extending ILRT test intervals up to 10 or 15 years like this. That data for pre-existing leaks of sufficient size to get us in trouble is about five failures in 182 tests, and that size is 35 L sub A, that's where the numbers come from.

So, I put all this in, requantified it. I find out that stuck open relief valve sequences seem to be significant, that's 80 percent of the increase in core damage frequency. The LOCAs and the transient initiators are the other 20 percent. The ATWS was almost a blip, I couldn't measure any significant change in ATWS.

To give you an idea, when I look at the baseline SPAR model which is not crediting -- or not considering any containment overpressure at all, and I perform my analysis, the change in the CDF is on the order of 3 times to the minus-8 per year, very small number.

MEMBER APOSTOLAKIS: What does the last sentence there mean -- "The change in the CDF is well within the Regulatory Guide guidelines"?

MR. STUTZKE: I needed some basis to look at the CDF, so I went into the delta CDF versus baseline CDF tables in the Reg Guide to see where we would fall. In other words, if this were --

MEMBER APOSTOLAKIS: Are you changing anything in the licensing basis?

MR. STUTZKE: Yes.

MEMBER APOSTOLAKIS: Are you? I thought you were addressing an issue of incompleteness.

MR. STUTZKE: It really is, and the question is how incomplete were we, and it doesn't seem that we're that incomplete.

MEMBER APOSTOLAKIS: Yes, but you don't need to invoke 1.174 to claim that, do you?

MR. STUTZKE: No.

MEMBER APOSTOLAKIS: No.

MS. RUBIN: This is Mark Rubin again. I think the point is this is a clear indication that there's no question of adequate protection, we're not raising any questions. And 1.174 criteria is one of the trip points that the Guidance identifies to where we might start to look a little deeper, ask a few additional questions, and you're three orders of magnitude below it.

MEMBER DENNING: Were these conclusions for both Ps and Bs?

MR. STUTZKE: Only Bs.

MEMBER DENNING: Only Bs.

MR. STUTZKE: Only Bs so far.

MEMBER DENNING: So far. Okay.

MR. STUTZKE: It's a lot of work to modify the SPAR models.

MEMBER DENNING: There's certain plants, though, that require the credit, yes?

MR. STUTZKE: That's right.

MEMBER DENNING: And another issue is that we really don't know how close plants are in LOCAs to the NPSH margin anyway because of the amount of debris on there, so it's -- I'm not sure we're in a position to be able to completely evaluate how important that NPSH margin is.

MR. STUTZKE: Yes, I certainly agree for the PWRs. I can't comment on it now because we haven't looked at it.

MEMBER APOSTOLAKIS: Why didn't you put the number on the screen, I'm curious? You told us it was 3 times to the minus-8.

MR. STUTZKE: Because I calculated it two days ago.

MEMBER APOSTOLAKIS: And it takes more than two days to prepare a slide?

MR. STUTZKE: You guys need your slides in advance.

MEMBER APOSTOLAKIS: Oh, it's our fault, Marty?

MEMBER DENNING: Now, some plants are more susceptible -- even the Bs -- some plants are more susceptible than others, right?

MR. STUTZKE: That's right.

MEMBER DENNING: Is that 3 times 10 to the minus-8 averaged over all plants, or is that for the --

MR. STUTZKE: No, that's the Mark I.

MEMBER DENNING: That's for the Mark I and the Mark I is the issue?

MR. STUTZKE: It's the classic Mark I.

MEMBER DENNING: And that's the one that's the greater issue.

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: So, 3 times to the minus-8 is what? I mean --

MR. STUTZKE: Well, it's for a single plant, it's a point estimate of just the change when adding in the credit for overpressure --

MEMBER APOSTOLAKIS: But was it a range of numbers and 3 times to the minus-8 was the largest?

MR. STUTZKE: No, just for a single plant, a single SPAR model, which is representative of a single plant. In other words, I can't tell you that I've looked at all the BWRs.

MEMBER APOSTOLAKIS: Okay. Okay.

MEMBER POWERS: Why would this be surprising that there would be a small number? I mean, if that's the only thing wrong with the plant -- plants are reasonably robust things. Don't you have to look at a range of other configurations to see if you're going to have a problem?

MEMBER APOSTOLAKIS: Like what configurations?

MEMBER POWERS: I don't know, I'm just asking the question.

CHAIRMAN WALLIS: We do have some other presenters.

MR. STUTZKE: I'm almost finished. The other thing that I will add in here -- and I guess I can forego the other slides -- is that I did look at the impact of increasing ILRT frequencies. The numbers I gave you are based on the three tests in ten years. I have calculated numbers for one test in ten years and one test in 15 years, which is small. One test in 15 years is about 2 times 7 to the minus-7, so it's small.

So, the conclusion out of all this is at least on the one BWR that I've looked at is that I don't find any indication in risk base to tell me that I have an adequate protection issue here.

MEMBER DENNING: Are you effectively taking credit on the Mark I, however, that it is nitrogen inerted, and so we have a high reliability in containment integrities, is that --

MR. STUTZKE: Well, that ILRT data that was used to calculate the probability of pre-existing leaks just seems to be total number of ILRTs in the fleet -- all plants -- and there's only been five failures. Most likely, those are PWRs, so it's very conservative. I think that's enough.

CHAIRMAN WALLIS: Well, let's see now. If the risk is very small, and you've indicated it only happens with large break LOCAs or something, only happens as very unlikely events, and if you lose the pump due to NPSH, it doesn't really matter. You could equally lose it because of screen blockage.

MR. STUTZKE: That's true.

CHAIRMAN WALLIS: And that's unimportant, too. All this stuff is negligible?

MR. STUTZKE: I haven't assessed string or plug-in, just whatever is on the front.

CHAIRMAN WALLIS: The consequence is the same, isn't it -- you lose the pump.

MR. STUTZKE: That's right, but the PRA considers all possible ways of losing the pump, including that it just doesn't start, it's the maintenance at the time, and things like that.

CHAIRMAN WALLIS: So, are you telling me that losing the circulation pump is not an important thing to happen, it doesn't matter?

MR. STUTZKE: No, I'm not saying that at all. What I'm saying is that the increase in risk caused by losing the pump due to loss of NPSH due to holes in the containment is small. It's a very specific failure mode.

MEMBER DENNING: It's just the coincidence of a LOCA plus --

CHAIRMAN WALLIS: All those things are so unlikely.

MEMBER DENNING: Well, I think the critical things are just the incidence of a LOCA in combination with loss of containment integrity is really a very small number.

MEMBER APOSTOLAKIS: Well, another factor, though, that brings the number down is the probability that the operators will fail to do anything.

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: I mean, that's three orders of magnitude you're gaining there.

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: Which is the direct result of the fact that you have plenty of time, right?

MR. STUTZKE: That's right.

MEMBER APOSTOLAKIS: And also their training.

MR. STUTZKE: One way to look at it is defense-in-depth. I mean, first of all, it's not likely you'll lose the integrity of the containment because it's inspected, it's tested, it's built well. But even if you do, the operators have time to react.

MEMBER DENNING: On the BWR.

MR. STUTZKE: On the BWRs.

MEMBER RANSOM: We need to move along. We have one more speaker, I think. Maybe you can summarize.

MR. LOBEL: The conclusions, we've gone through them all, the risk is containment pressure for NPSH is negligible, there's a high confidence in the containment integrity, no change to operator actions is required, the reliance on containment overpressure may be the result of an over, parts of cavitation tested for short periods of time with no damage, and the credit for containment pressure for BWRs appears to be limited to the older models with high required NPSH models.

MEMBER RANSOM: Thank you.

Incidentally, there is one more issue that I guess you're also changing the SRP-6213 which has to do with the mass and energy discharge to the containment, and you're asking us to --

MR. LOBEL: Not as a part of this.

MEMBER RANSOM: Oh, this is a separate issue?

MR. LOBEL: Was that included? It shouldn't have been. It is being monitored, we didn't need to bring it up.

MR. SHERMAN: Good afternoon. I'm Bill Sherman, the Vermont State Nuclear Engineer, and we've also engaged assistance from David Lochbaum, who you probably know, from the Union of Concerned Scientists. I know we're a little bit behind timewise, and I believe that I can catch up -- not at 3:30, but as quickly as I can.

Also with us today is the Vermont Director of Public Advocacy, Sarah Hofmann, also representing the State of Vermont, and on behalf of Governor Douglas, we appreciate very much being able to come and have you hear our commends from the State.

The reason that we're here and our interest in overpressure relates to the nuclear plant in our State requesting extended power uprate. We have a State responsibility to review aspects of the extended power uprate, and as part of that we noted that the plant was requesting a change in its design basis. It did not previously take credit for containment overpressure, and with extended power uprate they requested to do that, and we are concerned about that. So, that is the reason that we're here.

We made a more detailed presentation to the subcommittee, the Thermal-Hydraulic Subcommittee, July 19th, and we have a summary of that presentation here. We will at times make reference to a reference plant. It is obviously Vermont Yankee because that's the plant that we review and that we're interested in in Vermont.

The reason that we're here is because of something that wasn't exactly made clear in the Staff's presentation. The Staff indicated that overpressure credit was granted for various need situations that came out of the sump/strainer reviews and had come from earlier reviews before Safety Reg Guide 1.1 had been issued, but somewhere along the line when extended power uprates began, extended power uprates, in their philosophy, used margin. Somewhere along the line there was a Staff decision to allow licensees to use margin by granting them extended power uprate to cut into the NPSH margin. I don't know that it was ever flagged as a particular policy change, and I think that's why we're here.

So, we're here because we found in Vermont that the Staff wasn't following its own guidance in Regulatory Guide 1.82, Rev 3. As a result, we initiated an Atomic Safety and Licensing Board proceeding, which is ongoing, questioning this use of overpressure.

CHAIRMAN WALLIS: You noticed that the Staff was presenting a revision to that Guide?

MR. SHERMAN: Yes, that's correct.

CHAIRMAN WALLIS: So, obviously, they were aware of some deficiencies in its own guidance at that time as it existed, in Rev 3.

MR. SHERMAN: I believe so, but I'm not sure if we didn't help them understand that.

CHAIRMAN WALLIS: So you can take credit

for Rev 4 then.

MR. SHERMAN: I'm not sure about that, but we all try and help each other. Our issue --

CHAIRMAN WALLIS: The thing that is of interest to this committee is whether you are now happy with Rev 4.

MR. SHERMAN: No, I think that what we're going to say here, given a minute, we're going to say that we prefer not, but we'll explain.

Our issue is not only with the licensee, but it's also with the Staff. With the licensee, the Atomic Safety and Licensing Board proceedings are structured to question what the licensee is doing, but we also have issues with what the Staff is doing. And in that regard, we have extremely high confidence in this body as a body which can consider this issue and can assist in resolving our concern.

This is what we would wish out of this meeting. One doesn't always get what one wishes. What we would wish is that the committee would carefully consider the technical issues surrounding the general allowance for crediting containment overpressure as proposed in Rev 4. We also would wish that the committee could provide some indication in the near-term of its position on this general allowance for crediting containment overpressure. As I say, one doesn't always get one's wishes, but that's certainly a wish that we have.

CHAIRMAN WALLIS: Well, this guide is not yet finished. It goes out for public comment --

MR. SHERMAN: We understand that.

CHAIRMAN WALLIS: -- and the final version that we advise about may look quite different from the one you have.

MR. SHERMAN: That's true, and therefore it may not be possible for the committee to provide an indication in the near-term.

CHAIRMAN WALLIS: We might be able to provide general indication of our position in some general way yet.

MR. SHERMAN: Perhaps so. As has been stated, the current overpressure credit guidance in Rev 3 is no overpressure credit except where needed and where the design cannot be practicably altered.

What we pointed out in power uprate is that because uprate is not needed, the plant works fine without it, uprate didn't meet that criteria and, also, we believe pretty strongly that the design can be practicably altered. And so this sort of Staff policy change that occurred to allow this cut into overpressure credit for power uprate was something in lieu of asking licensees whether their design could be practicably altered.

I don't know if it's appropriate for you to mention -- maybe not -- at this point I'm not sure.

MR. LOCHBAUM: What Bill is referring to is that the reference plant's reference owner has made a change at another facility when faced with containment overpressure, they just simply replaced the impeller pumps -- the impellers on the pumps, in order to avoid having to take credit for containment overpressure. So there are always alternatives. The reference plant -- it's not even clear that they did a consideration of what the cost or what the impacts of that possibility would be before ruling it out, they just went straight to the containment overpressure credit.

MR. SHERMAN: Vermont believes that the uncertainties are such that this guidance should not be changed, and let me explain that more clearly. What we believe is that the uncertainties in whether NPSH will be adequate and whether the pump will fail as a result of NPSH problems are high enough such that the additional conservatism that has always been present and provided by containment overpressure should be retained as an additional conservatism, a type of defense-in-depth, if you wish. And this will become more clear in two or three more slides, how -- what we feel about this.

In the subcommittee, we identified -- and I won't go through them here, I go through them two slides from now -- we considered numbered uncertainties 1 through 8, uncertainties associated with whether the pump will adequately function and whether there will be adequate NPSH. I won't read the slide into the record just now.

We provided the next slide that I'm going to show at the subcommittee presentation. Dr. Apostolakis has not seen it, but you'll see it here in just a minute. We're not quite sure that our framework is right, but at least it expresses what we're trying to show.

The total uncertainty or PRA should be the sum of events and challenges to NPSH adequacy. Mr. Stutzke just identified that he had looked at LOCA, ATWS,a nd Safety Relief Valve Discharge, and we're happy about that because that's a change from the subcommittee presentation. The Safety Relief Valve Discharge, as we would expect, is more significant because it happens more often; the LOCA, less significant. I don't know that he identified whether he had looked at Station Blackout, which probably is more significant, or Appendix R Fire which is probably of lesser significance. But the sum, or the overall change in CDF should be the sum of all of those challenges to NPSH.

So, if we look at maybe a way of looking at the challenges for the pump failing due to inadequate NPSH, one uncertainty is that the NPSH-r is not sufficient. Mr. Lobel, in his presentation, spoke about a cavitation slide. He didn't number his slides, but on that slide it said the Staff has approved pump operation under cavitation below NPSH-r with or without credit for containment accident pressure based on pump cavitation testing. Well, that may be true, but on the reference plant, the one we reviewed, there haven't been cavitation tests, or at least the licensee doesn't have them nor has the Staff asked the licensee for them. And our point there, Dr. Apostolakis says that there's an uncertainty. There's an uncertainty that somebody could assign a value that could feed into a CDF for pump failure.

Debris head loss more than expected. Again, there's an uncertainty associated with that. It was interesting -- and my goal is no to criticize my colleague's presentation exactly. In answer to a question about debris head, the answer was it's a resolved issue unless it needs to be brought up again. And that's just our point, there's some uncertainty associated with whether the debris head loss is more than expected and it ought to be quantified, and we ought to figure it out before we give up the initial margin that exists -- we voluntarily give up the initial that exists with containment overpressure.

The NPSH margin insufficient, Mr. Lobel spoke about how if we operate at the NPSH-r, we may be operating -- or even a little above it -- we may be operating at the worst cavitation region, and there's a question I believe at the end of his discussion was that the industry needs to do more work there, but our point is it's an uncertainty, and if it were quantified -- you could attempt to quantify that uncertainty and come up with a probability of the pump failure due to inadequate NPSH.

Containment fails to hold pressure. Actually, Mr. Stutzke's presentation only considered that item. The probability that he gave you only considered that item, and our concern is greater than that. Our concern is that you shouldn't give up overpressure because all of these items contribute to the possibility of pump failure, and you ought to hold it in reserve because the uncertainties are great enough.

One comment about Mr. Stutzke's presentation is that he indicated that he had added the MSIVs to his fault tree, which we suggested at the subcommittee weren't included. He indicated that he used failure rate data from NUREG-1493, I believe the number was, from 1995, however, at the subcommittee we provided information for the reference plant over the last ten years of actual tests which indicated, I would guess, a much higher failure rate than that NUREG, though I haven't had the opportunity to look at it. My point then is that there's an uncertainty even with the numbers that he's gotten, and that uncertainty perhaps could be taken into account somehow.

Insufficient developed pressure or sump temperature higher than predicted relate to -- mostly relate to the list of conservatisms that we didn't discuss because of time, but they were discussed by Mr. Lobel at subcommittee. Still, there is some probability of each one of these things, the pressure being insufficiently developed or the sump temperature higher than predicted.

My last item on the fault tree here is operator fails to retain sufficient pressure. That's real interesting. First, one of the members asked a question -- I believe it was you, Dr. Ransom -- asked a question about isn't the operator conflicted, reducing temperature but having to keep it up. And Mr. Lobel's answer was there will be a place in operating procedure which says where the operator can reduce the pressure to, but not on the reference plant because at ASLB one of our assertions was that the licensee stated they were making no changes to their emergency operating procedures, we were not granted a contention because the reference plant basically swore that they did not need to make any change, not that that should be resolved here, only that that's enough to verify that there is an uncertainty, a real uncertainty as to whether the operator will retain the amount of pressure that he's supposed to have.

And if there was any overriding uncertainty, it's the overriding uncertainty of things that haven't happened yet, that you don't know about. It might be trite to talk about Davis-Besse. All of the committee understands the sump/strainer history and the fact that we've had three bites at the apple to try and get that one right. The Fitzpatrick Torus leak is a new issue, it's a containment integrity issue that, again, whether it will be a single event or whether it will be the beginning of a new thing that needs to be reviewed, we don't know, but most likely existing PRA and probability analysis haven't considered that.

Just this last week, there was a Hope Creek vacuum breaker failure. It might be again. It might be isolated. But the overriding thing is that in all these probabilistic analyses, as you well know, the bugaboo is those things which haven't happened yet.

This slide is out of character for the way that I want to be because, again, it sounds a little bit trite, but it is our concern in Vermont, and that is that a most unfortunate situation would be to give up containment overpressure and then to have one of these uncertainties come around and then to have to go through a period like the PWRs are in right now where it is pretty well asserted that until they get it fixed, it's not in as good a safety consideration -- as good a safety position as we'd like to have it. We would hate to have that come true. The reason it's a bad slide is because the "what if" kind of discussions are never very satisfying.

Here's our summary. We believe that the uncertainties that we've identified are real, even using the words that the Staff made in their presentation. If you take it from a deterministic point of view, we think the uncertainties are great enough to direct that you should hold overpressure as a conservatism.

If you take it from a probabilistic point of view --

CHAIRMAN WALLIS: You mean the lack of credit for overpressure?

MR. SHERMAN: Yes. If you take it from a probabilistic point of view, we just don't think that the PRA techniques that we've seen -- and even Mr. Stutzke pretty much identified that there hasn't been a lot of it out there -- are enough to have us give up this overpressure credit voluntarily.

So, here's what Vermont is really requesting, and that is that we're very concerned about this, but we have high trust in your ability to look at it, and we hope that you consider all of this very carefully. I hesitated whether I would say this, but I believe that when you asked the Staff at the subcommittee to quantify the conservatisms, and then they came back today and said, "Oh, gosh, we just couldn't do it", I don't think you should accept that as an answer, or I don't think you should assent to this while accepting that as an answer. I had a man work for me 25 years ago who said to me, "I can't possibly give you a schedule for delivering radiation monitors", and I looked at him and at the next round of layoffs he wasn't with the company anymore.

MR. LOCHBAUM: Duly noted.

MR. SHERMAN: But I don't mean to say that -- I just don't think you should accept that. I think that you should look at it very, very carefully, but we do appreciate the ability to be heard on this. Thank you.

MEMBER RANSOM: Thank you. I guess a little bit of a reply, I'm not sure we're being asked to approve or disapprove of this revision, but rather whether to release it for public comment.

MR. SHERMAN: As I said, we understand that, and if you were able to say anything on it at this point, it could be helpful for the State of Vermont. If not, then next time is another time.

MEMBER RANSOM: Are your concerns, or Vermont's, a fear for possibility of an accident, or what is motivating -- or is it there's not a need for this power uprate, or combination?

MR. SHERMAN: The power uprate is a voluntary endeavor by the utility. In the State of Vermont, as a matter of fact, we have looked at it on an economic basis, and we think that it would be a useful thing, but as all say, safety overrides economic benefit.

We have a high suspicion that there are practicable alternatives well within the bounds of the overall cost of power uprate. And so our basic feeling is that we are not sure what safety -- what the degree of safety being given up in granting this overpressure credit is, but we suspect that it would be better not to grant it, that it would be better to maintain the current guidance, which is where needed or cannot be practicably altered.

MR. LOCHBAUM: Dr. Ransom, I just wanted to add one thing to what Bill said in response to your question -- really, the first question about the -- you're being asked to comment on whether this Draft Reg Guide should go out for public comment or not. That is, indeed, true, but it's also true that the practice outlined in the Draft Reg Guide is really what the Staff has been doing to this point. So,k if there are any concerns about that practice which is in effect today and is being applied to the reference plant and others in the pipeline, it would be great for the ACRS to articulate those concerns now. It would be even better if the final version of the Reg Guide captured that, but it's not that we're going to something and we're on solid ground now, we're not on solid ground now. The hope is that someday that will be corrected, but it would be nice to address that deficiency today as clearly as could be articulated.

MEMBER RANSOM: I'm sure there's going to be an interesting discussion. Thank you.

CHAIRMAN WALLIS: Are we finished now with this?

MEMBER RANSOM: Well, I assume we're out of time, so I won't ask to go around the room. I think we'll do that later, if that's okay with you, Mr. Chairman.

CHAIRMAN WALLIS: Unless a member has some burning desire to express himself on this matter now -- I don't notice that -- so I'm quite happy to move on to the break.

MEMBER RANSOM: I think at some point I need some help if I'm going to write a letter on this subject, and it appears to be difficult.

MEMBER APOSTOLAKIS: You mean you haven't written it yet?

VOICE: I'll lend you my computer.

CHAIRMAN WALLIS: Okay. We will take a break for 15 minutes. We'll come back at five minutes past 4:00.

(Whereupon, a short recess was taken.)

CHAIRMAN WALLIS: I want to call us back into session. I think we have a quorum. I assume we have some speakers.

MEMBER POWERS: We have speakers. We have knowledgeable individuals. We have issues. We have a Draft Resolution.

CHAIRMAN WALLIS: In that case, we have a very interesting technical topic coming up, and I will ask my colleague, Dana Powers, to lead us through it.

MEMBER POWERS: And I will do so gladly. Mr. Chairman and fellow members of the ACRS, we're going to deal with a real reactor issue today, reactor fuel.

As many of you know that I have enjoyed the last few months of re-examining 10 CFR 50.46 and the definition of design-basis accidents, and much of that attention has been devoted to the arcane field of fracture mechanics and the definition of break size, which fails to meet the standards of precise science.

We do have other requirements in the

regulation, and that principally deals with the requirement that we'd like to keep the core coolable, or in thinking about what it takes to keep the core coolable, you would like to maintain the geometry of the core. In order to maintain the geometry of the core, you would like to assure that the cladding on the duel does not become embrittled. As a consequence, a variety of requirements have been included in the regulations that deal with cladding oxidation, and when they were done, they were done in a way that is particularly clad type specific, and it's technology specific.

Well, this has become burdensome for all concerned as we move first to higher burnup fuel and then as a consequence to evolving and improving types of cladding. So, it is evident that if we're in the business of relooking at 50.46 for the definition of a design-basis accident, it might be opportune also to look at the coolability requirements. In addition, some research has been conducted in this area of cladding taking high levels of burnup, and some discoveries have been made that are pertinent to the issue of embrittlement.

Consequently, the RES staff has taken this research and proposed what might be a candidate alternative, and they will speak to that alternative to us and the underlying research. We will also have presentations by EPRI and the industry on their view about this research and the possible alternatives.

They are looking to us for a letter to RES which I believe would say to the effect that there are good bases for us continuing along in this direction. So, the committee, when it looks at this research, I think should be bearing three questions in mind. One is, of course, should be looking to amend or alter the requirements concerning coolability in the Code of Federal Regulations at this time based on the research we have in hand.

If we agree that should be done -- and the motivations for that are both research and the burden imposed by a highly specific regulation -- if we agree that that should be done, the next question is should be looking at an amendment that parallels in specificity the existing regulation, or should we look at a higher level change and relegate specificity that might deal both with cladding type and regulations to regulatory guides.

And, finally, if we agree to the other first two questions, then is the alternative being advanced by RES the one that we would espouse at this time?

With that introduction, I will turn to the first speaker who, on my agenda, is listed as Dr. Meyer, unless the group has some opening comments to make. Dr. Meyer.

CHAIRMAN WALLIS: I have a question. Are we going to hear from NRR at all?

MEMBER POWERS: They are not part of this equation at this time.

CHAIRMAN WALLIS: Okay. Thank you.

MEMBER POWERS: As far as I know. On my agenda, they are not.

DR. MEYER: NRR is fully involved in our discussions, but at the moment the presentation will be made by --

MEMBER POWERS: They are assuredly welcome at any point to make comments and observations as they see fit.

DR. MEYER: In the late 1980s and early '90s, we became aware of burnup effects in fuel pellets and in fuel rod cladding that we hadn't anticipated. We suspected that these might have some impact on fuel damage criteria that are used in licensing, since most of the criteria had been derived from data on unirradiated or low-burnup materials.

In 1995, we initiated a small effort at Argonne National Laboratory to explore these issues, and by 1997 we had organized a significant research program at Argonne to determine the effects of burnup and of the new cladding alloys that had been introduced to achieve higher burnups on the criteria used to analyze loss of coolant accidents. From that time forward, we've had industry cooperation in the effort.

I want to especially acknowledge the Electric Power Research Institute, EPRI, and their early lead in this cooperation. Within a few years after EPRI joined the effort, the cooperation grew to include Framatone, Westinghouse, Global Nuclear Fuel, and the Department of Energy, as well as good international cooperation with organizations like Kurchatov Institute in Russia, Japan Atomic Energy Research Institute, and the Institute for Radiological and Nuclear Safety, IRSM, in France.

Our work is not finished, and we have a formal research plan in place to continue confirmatory work after revising the regulatory criteria, There are remaining uncertainties and there is a need to develop streamline procedures. However, the work has progressed to a point at which we want to define revised criteria that can be used in a rulemaking effort sometime next year.

So, my purpose today is to describe the proposed criteria, to show you the supporting data, to point out where there are holes in the data and to say what we are doing about it. And my challenge has been to try and capture these complicated burnup and alloy effects with simple changes to the embrittlement criteria so that there is little or no impact on the large ECCS evaluation models that are used in the safety analysis. So, I'm going to be talking specifically about the -- what we call the embrittlement criteria in 50.46, subparagraphs (b)(1) and (b)(2). One of these two criteria is the peak cladding temperature limit of 22 degrees Fahrenheit, 1204 Centigrade --

CHAIRMAN WALLIS: I assume 4 is unimportant because in your slides you use 1200 C. The 4 is unimportant. You use 1200 C to mean 2200 F.

DR. MEYER: Yes. That's right. In the rest of the slides, you'll just see 1200. Okay. And the current limit on cladding oxidation is 17 percent. These are numbers that most of us are familiar with.

In Appendix K, where it describes evaluation models, there is a requirement to consider tow-sided oxidation within an inch and a half either direction of the rupture. And more recently, in 1998, there was an information notice that clarified a point in an attempt to make a sort of interim accommodation of the burnup effects, and that point was to consider total oxidation which is stated in the regulation to mean the sum of the pre-accident oxidation or corrosion, and the transient oxidation. So, those two together should be limited to 17 percent.

MEMBER POWERS: Dr. Meyer, I think it might be useful for the committee to note that the first two requirements, the temperature and the oxidation, are intimately coupled phenomenologically, and consequently that peak temperature -- clad can only set at that temperature only for a very, very brief period of time.

DR. MEYER: We may get into some of these technical details just depending on the question.

CHAIRMAN WALLIS: Now, are these just --

MEMBER POWERS: If they're going to ask about 4 degrees Centigrade, I figure we better --

CHAIRMAN WALLIS: Is there embrittlement criteria of the peak cladding temperature, you're only concerned about its effect on embrittlement more than anything else?

DR. MEYER: There was -- as Dana really tried to capture in his opening remark, there was a sort of cascading logic that started from a general design criterion that said make sure you can cool the core following a loss-of-coolant accident, with regard to the emergency core cooling system.

When you go down that cascade, what does cooling the core mean? Keep the geometry, keep the pellets in the cladding, and because there are loads of perhaps unknown magnitude, the Commission, in 1973, concluded that the best way to ensure that was to make sure the cladding had some ductility so that it wouldn't shatter during or after --

CHAIRMAN WALLIS: So it's the oxidation that's most important for determining the embrittlement?

MEMBER POWERS: Just say yes, Ralph.

CHAIRMAN WALLIS: Well, why does the temperature come into it?

DR. MEYER: Why does the temperature --

CHAIRMAN WALLIS: Why does the temperature come into this embrittlement.

DR. MEYER: Okay. I'll tell you now, and we'll come to it again --

CHAIRMAN WALLIS: You'll tell us that.

Okay.

DR. MEYER: The primary effect has to do with the diffusion of oxygen into the metal, and also with the solubility of the oxygen in the beta phase. You're going to be in the beta phase with the high temperature. And up to 1200 degrees Centigrade, approximately, the solubility limit in the beta phase is low enough that the oxygen does not embrittle the beta phase. Above 1200, it can hold enough to embrittle the beta phase. So, when you do empirical experiments, what you see is as soon as you start testing embrittlement for temperatures above 1200 degrees, you see it rapidly deteriorates. And so the 17 percent number did not work for temperatures above 1200 degrees.

MEMBER SIEBER: And the 1200 is not an absolute number, there's lots of margin that was put in --

DR. MEYER: No, actually, I think this is --

MEMBER POWERS: This has to do with phase stability analysis.

DR. MEYER: Yes, there are margins in some other senses, but not in terms of the ductility. It's a -- it starts falling off pretty rapidly above 1200.

Okay. So, what I'm going to do here is to jump right to the end, tell you the bottom line, and then come back and try and show some logical derivation of this.

And I won't read everything that's on here, but first of all we have data from the Argonne program. We are trying to develop changes that are minimal. We're going to stick with the 2200 Fahrenheit limit, it makes sense. What we plan to do with the 17 percent limit is to replace that number with a derived value that's derived from measured tests that we would specify. We would have to have a Reg Guide to go along with this to describe the details.

Now, we've done this. We've decided what tests are appropriate and we've made the measurements and applied it to the current alloys that are used in U.S. reactors -- Zircaloy, ZIRLO, and M5 cladding -- and what we find is that if we're careful, that 17 percent minus the corrosion thickness works. You do need a time limit at the lower temperatures, and I'll explain why you need that.

CHAIRMAN WALLIS: You don't need a time limit at 1200?

DR. MEYER: You're going to run into the

oxidation limit at 1200 before you would run into the time limit.

CHAIRMAN WALLIS: Then the time at 1200 is irrelevant?

DR. MEYER: No, it's not, because the oxidation limit of 1700 percent is going to --

CHAIRMAN WALLIS: You're going to run into that first.

DR. MEYER: Yes.

CHAIRMAN WALLIS: Okay, fine.

DR. MEYER: This is going to be something like 650,000 miles or five years, whichever comes first.

MEMBER POWERS: 50,000 miles or five years -- none of those are on the correct scale by several orders of magnitude.

(Laughter.)

DR. MEYER: We're also going to do all of our calculations with the Cathcart-Pawel oxidation correlation whether it describes the actual amount of oxidation or not because, as you will see, what matters is time at temperature, not how much oxide grows on the surface, and this correlation gives us a time scale that's very handy. When we do all this for these current alloys, we don't find any safety problems and we don't think any reanalysis would be needed.

Now I'm going to start back at the beginning and try to tell the whole story and see how we get here, and try and do it within the time that you have allotted, whatever that is.

I don't want to insult anyone by going back too far, but from a cladding point of view, this is what a loss of coolant accident looks like. The cladding heats up eventually. It gets up to somewhere around 800 degrees. There's a big pressure differential because you've lost the system pressure, you've got a high internal rod pressure, the cladding becomes plastic, it deforms in an unstable manner, and it ruptures just like a balloon pops. There's some thin cooling effect that will slow the temperature rise down at that location. This is not to scale, so not to worry about --

CHAIRMAN WALLIS: When did this rupture, why is this not a bad event?

DR. MEYER: Why is --

CHAIRMAN WALLIS: Why is this not loss of geometry and it's ruptured, just to explain to the public. I mean, rupture sounds like a break. Ballooned and ruptured, it's popped. So, why is that not loss of geometry?

DR. MEYER: Because the concept for loss of geometry was to keep the rod looking more or less like the rod and keep all the fuel pellets inside.

CHAIRMAN WALLIS: It's to keep the pellets inside, that's what matters.

DR. MEYER: Right. And so here is --

CHAIRMAN WALLIS: It still retains the fuel then, still retains it.

DR. MEYER: Right.

MEMBER POWERS: You have to go beyond this, you could lose coolability. You have to contained the pellets in the rods, if you broke the rods up into a fine enough segments. So you want to maintain rod geometry and you want to keep the pellets inside the clad.

MEMBER SIEBER: But ballooning is allowed.

MEMBER POWERS: What did you say?

MEMBER SIEBER: Ballooning is allowed to some extent.

MEMBER POWERS: You've got to give something. It's not going to be a happy event here.

DR. MEYER: Okay. So this happens to be a BWR rod that has a high burnup on it, about 60 gigawatt days per ton, and it was -- this much of it was taken through a LOCA-type temperature transient in the hot cell up at Argonne. It did rupture, and we observed many things about it, some of which I can tell you about in the time that we have.

CHAIRMAN WALLIS: It only ruptures at one place?

DR. MEYER: Only ruptures at one place.

CHAIRMAN WALLIS: Releases the pressure.

DR. MEYER: Releases the pressure, there's no more driving force. One thing that I did want to point out just for you to keep in mind here is that the rupture occurs before the oxidation process really kicks in. So, the oxidation and the diffusion of oxygen into the metal really occurs after the rupture event which, just by coincidence, happens about the time that the material is going through a phase change. It's low-temperature phase is hexagonal close pack, it's high-temperature phase is a body center tube, and we just call them the alpha phase and the beta phase. So, all those things matter in terms of the ductility that is going to be left after it goes through this transient.

So, what you want to do is you want it to have ductility when it gets back down here.

CHAIRMAN WALLIS: When the brittleness is really going to come is when you quench it, is that correct?

DR. MEYER: That's correct, and subsequently, but during the quench and for any loads that might be associated with the --

CHAIRMAN WALLIS: The concern is if it's brittle then it would not exactly shatter, but it would shatter enough to let the fuel fall out?

DR. MEYER: Right.

MEMBER POWERS: I don't know, it exactly does shatter.

CHAIRMAN WALLIS: It breaks up like a glass?

DR. MEYER: Yes, sir.

CHAIRMAN WALLIS: Like a broken glass?

DR. MEYER: Yes, sir.

CHAIRMAN WALLIS: And all these pellets still stand --

MEMBER SIEBER: No, no, no. They go to the bottom of the vessel.

MEMBER POWERS: I'm worried about the physics that goes on at Dartmouth here.

(Laughter.)

CHAIRMAN WALLIS: That sounds like a loss of geometry.

MEMBER POWERS: That will qualify as a loss of geometry.

MEMBER SIEBER: You can cool anything, it's the temperature that it gets to in the process.

(Laughter.)

CHAIRMAN WALLIS: Because of bed reactor or the fuel pellets, is that what they become?

MEMBER POWERS: I suspect that if you shattered the fuel rod, it better be represented as a mud pot, a very hot one. Please continue, Ralph.

DR. MEYER: Okay.

MEMBER POWERS: We're getting a little punchy here.

DR. MEYER: Now the subject turns a little more metallurgical and becomes quite complicated because we're now aware of five sort of separate mechanisms that can lead to embrittlement, and we need to make sure that the regulation accommodates all of them, and only two of them were known when the regulation was developed, so we've got some explaining to do here.

I'm going to comment briefly on these five, but I'm going to try to avoid going into too much detail because it took us a whole day to do this back in July.

This is a sketch of the oxygen distribution in a thickness of cladding at high temperature during the oxidation process. So, you have oxide building up at the surface. You have -- the material has all transformed to a beta phase -- actually, this is a diagram after it has come down. Sorry. I just noticed the word "prior" up there.

Let me just back up and say this is the oxygen distribution that we expect to find after the cladding has gone through the transient. You're going to see an oxide on the surface. You're going to see some of the alpha phase that is rick in oxygen and brittle, and you're going to see some alpha material that was in the beta phase at the high temperature, and remained at a low enough oxygen concentration that it stayed in the beta phase when it was at the higher temperature, and then it came back into the alpha phase it still had low oxygen concentration and was ductile. So, this is the only thing that's giving you the ductility in this cladding after it's gone through the transient -- this prior beta phase.

Now, the first thing that we did was to take unirradiated specimens of the three cladding types and run a series of tests where we ran them through -- where we held them at different temperatures for different periods of time -- this is like a separate effects test, so this is not an integral LOCA test, but we're now going back to try and parse this thing up into the different temperature regimes so that we can put it back together in a LOCA analysis, and we measured the ductility, the deformation of ring specimens just like had been done 30-odd years ago, as a function of temperature. And here are plotted data for I'm going to call it "New Zircaloy" -- and I'm going to distinguish "New Zircaloy" from "Old Zircaloy" and it has to do with surface preparations and some things that affect it, but we'll get to that later. This is the kind of Zircaloy that is currently in operating reactors.

And you see that if you simply plot a measure of deformation as a function of the predicted oxidation, that this Zircaloy material shows ductility out to at least 17 percent. The subtleties of this plot are that zero-ductility is reckoned to be at 2 percent -- for reasons that the guys that did the test would have to explain to you. It's a ring test and it has some bending in it, and some other things, so zero is 2 percent on this parameter. And the 17 percent is a calculated value with the Cathcart-Pawel correlation. And how you need to view this is to think of the Cathcart-Pawel predicted oxidation percentage as a time scale.

So, at all three of these temperatures, the time at temperature needed to embrittle the cladding was about the same as the time needed to predict 17 percent oxidation with that correlation. Found the same thing, more or less, for ZIRLO and for M5 cladding.

So, what we've seen in this series of tests on the unirradiated tubes is that unirradiated modern cladding fits the picture that we have from our existing regulation. There's no burnup, so there's no corrosion on these rods, we'll get to that presently.

But old Zircaloy doesn't fit the picture, and there are other materials that don't fit the picture, and I want to talk about that just briefly. If we take old Zircaloy -- and in this case, it's the archive material for the high-burnup H.B. Robinson fuel rods that we have in the hot cell, it's all fairly old -- this cladding had been etched and the surface was not polished smooth, both of these preparation techniques turn out to be important in terms of the growth of this oxide on the surface -- and it embrittled at about 13 percent rather than 17 percent.

Now, if you look back historically, we had 17 percent in the regulation, but we also had Baker-Just correlation rather than Cathcart-Pawel correlation. And in fact, the time needed to calculate 13 percent with the Cathcart-Pawel correlation is approximately the same time you need to get 17 percent with the Baker-Just correlation. So, in effect, we have confirmed Hobson's results of 30-some-odd years ago, and the rule as it was applied with Appendix K.

The point that I want to leave with this slide is that 17 percent is not a universal number. It is material-dependent.

CHAIRMAN WALLIS: It's correlation-dependent, too.

DR. MEYER: It's what?

CHAIRMAN WALLIS: Correlation-dependent.

DR. MEYER: Well, you could look at it that way. Now, the first two mechanisms, both of them had to do with the diffusion of oxygen into the beta phase -- and let me slough over the distinction between the two mechanisms, unless you really press me on that.

The third mechanism is one that we discovered fairly recently, and this has to do with breakaway oxidation, and we found that all of the alloys tend to experience breakaway oxidation if you hold it at lower temperatures for a long time -- lower temperatures meaning 900, 950, 1000 degrees Centigrade -- and you've got to be up high enough where the oxidation --

CHAIRMAN WALLIS: What is breakaway oxidation? What is breakaway oxidation?

MEMBER SIEBER: Very rapid.

CHAIRMAN WALLIS: It sounds like a fire.

DR. MEYER: Well, here are a couple of pictures. Zirconium dioxide can have several crystallographic forms. The two that we deal with are monoclinic and tetragonal, and it's kind of on the cusp, it doesn't robustly stay in the nice black tight tetragonal form, and if certain things are unfavorable, it can grow this monoclinic oxide which is not protective and tends to start developing blisters and shedding pieces like that.

MEMBER POWERS: Maybe it helps, the rate of oxidation is limited by the development of a product layer --

CHAIRMAN WALLIS: That's what I realize, when it breaks away, once it breaks away, you've exposed something inside.

MEMBER POWERS: The thickness of a

protected layer is lost.

CHAIRMAN WALLIS: Hence, the breakaway.

DR. MEYER: The problem here is not specifically with the rate of the oxide growth because as I should have pointed out on the previous slide, you've got plenty of oxide sitting on the surface to diffuse into the metal. It's not going to matter a whole lot whether you grow a lot more or a little more, what does matter is that this oxide lets hydrogen in. And so when this occurs, if you look at the hydrogen pickup, you will see that for times after this has started appearing, that the hydrogen absorption skyrockets, and the hydrogen then affects the solubility limit and the diffusion limit for oxygen which end up embrittling the material.

So, what we like is to maintain an oxide that looks like this one -- by the way, this is the Russian E110 cladding and the Framatone M5 cladding. Both of those are Conium 1 consent niobium alloys. They are similar in composition, but they have some different fabrication characteristics. And one of the things I've got to mention since I've got an audience here, one of the things that we're very proud of from our research program is we figured out what are the fabrication steps that produce this kind of sensitivity, and they weren't at all the ones that we were expecting. Surface finish, which I've mentioned, is one of them, and the other one was the ore reduction process. It mattered whether you used the chemical Crowel process or an electrolytic process for refining the zirconium sands, the ore, and has to do with impurity. So, all of this is about growing ionic crystals on a substrate and the impurities in the ionic crystal which have different valences than the host, the aliovalent impurities. So, that's another subject, but the practical result of all of this is the hydrogen absorption, and it's this effect that we want to prevent by using a time limit. If you get to the time limit before you get to the oxidation limit, then you're going to lose the embrittlement -- I mean, you're going to lose the ductility.

Here is a recent slide from a CEA publication which was done jointly with CEA, Framatone, and EDF, and this is hydrogen content as a function of time, and this number, if you can't see it, is 5,000 seconds. So, at 5,000 seconds for both Zircaloy-4 and M5, they start seeing a rapid increase in the hydrogen absorption, indicating the onset of the breakaway process. I have this 5,000 second point on a figure later on in the presentation.

Okay. The fourth mechanism that we need to take account of occurs in the ballooned region. This mechanism was discovered in the early 1980s, and we didn't really do anything about it at that time. What happens in the ballooned region is you have a rupture, so you have some steam that gets on the inside, and the steam oxidizes on the inside -- we've always known this was going to happen, it's written into the regulation that you have to address that.

What we didn't understand until the 1980s was that the hydrogen that is freed from the dissociation of the water molecule is kind of trapped on the inside of the cladding and isn't swept away as readily as the hydrogen is swept away on the outside. So, you get an enhanced hydrogen absorption inside the balloon, and this manifests itself in a couple of very high concentration bands which are going to cause brittle locations in the balloon. Even if you stay below the criteria that are in the regulation, you're not going to protect ductility at every location in the balloon.

There's not a lot we can do about changing anything in the ballooned area, and so what we're proposing to do is to do nothing in terms of the prescription that's already in the regulation, but to leave it in place so that you apply the oxidation limits in the ballooned area as is currently done. This will not protect the entire balloon surface from embrittlement, but it will protect some of it from embrittlement. And so the consequence that we expect from this is that if the brittle regions experience a load, that they will fracture in a clean manner. And then we make these arguments to say that this is acceptable.

For the record, that was slide 16 where these arguments are written down.

So, let me go on now to the fifth and last embrittlement mechanism, and this is the one that contains the burnup effect. It's the only one that contains the burnup effect. And it comes from the corrosion process, but not from the oxide itself, but from the hydrogen that is absorbed during the corrosion process. So, during the normal burnup lifetime, as the cladding picks up 20 or 30 or 40 microns of corrosion oxide thickness on the surface, it's also absorbing a small fraction of the amount of hydrogen that was released during this process. And it's that hydrogen then that enhances the solubility of oxygen in the beta phase, also probably increases the rate of diffusion of the oxygen in the metal, and shortens the time required to embrittle that material.

So, the interim requirement was to subtract the corrosion thickness from the oxidation limit, which was at that time engineering judgment was a guess, it was a good guess, and it appears to work, at least approximately. And we have one set of data so far that shows this, and we have a couple of other sets of data that we hope to take very soon on the M5 and the ZIRLO cladding, and we'll see if we can continue to confirm this. This is a little bit plotted in a little bit of a confusing way, but the red triangles in Figure 18 are the actual data points. And what we've done is to add to each of these points the corrosion thickness of that specimen converted to a percentage of the cladding thickness, and then connect those points up with a line. There is another datapoint up here which is how we know where to draw this straight line. So, this straight line just connects the points, it doesn't do anything more than that.

But you can see from this that the ductility loss is occurring at about 13 percent. This is the H.B. Robinson fuel. It's the old cladding type, and this is the same --

MEMBER BONACA: The red dots, right? The

Robinson is the red triangles?

DR. MEYER: Well, both of these are Robinson. These are the data that we took before adding to them the corrosion thickness. So, adding the corrosion thickness is just the opposite of subtracting from the limit, which would be 13 percent for this old cladding type, based on the testing with the unirradiated material.

So, in the next two slides I want to summarize as succinctly as I can the criteria that we're proposing. So, these are to be considered for possible rulemaking. And as I mentioned before, we're not proposing to change the 2200 degree Fahrenheit temperature limit. That still fits into the picture just exactly as it did before. But we could tell from those data slides that for the oxidation limit, that 1200 degrees was the most critical temperature. You had more margin at 1100 and at 1000, provided you didn't have breakaway oxidation.

So, what we propose to do is to replace the 17 percent number in the regulation with a statement that would specify that you perform the test that had been performed to get the 17 percent number, on unirradiated specimens of the cladding of interest.

Now, we've already done this for Zircaloy, ZIRLO and M5, and for the modern varieties of those the number we got was 17 percent. But we also have examples where you would get other numbers --

CHAIRMAN WALLIS: Is this going to be a measured oxidation level or is this going to be a Cathcart-Pawel predicted oxidation time?

DR. MEYER: It's going to be a Cathcart-Pawel calculated oxidation time. And it turns out at 1200 degrees, Cathcart-Pawel and the true oxidation for all three of those alloys are virtually the same. They are not the same at the lower temperatures.

Step 2 now addresses the breakaway oxidation phenomenon, and here one would take additional samples and oxidize them in steam at temperatures in the range of 800 to 1200 degrees, to determine the time required to initiate breakaway oxidation.

You saw one such graph just a minute ago, the CEA data, where they showed that this onset took place at 5000 seconds at 1000 degrees Centigrade. So, you would explore the temperature range where the oxidation process is active, and find the times required at those temperatures to get the breakaway phenomenon.

And then the third step would be to

determine the amount of corrosion or oxide thickness after normal operation on the fuel of interest. So, if you are analyzing a core, you would predict how much corrosion is going to be on the fuel at whatever time you're going to do the -- time in the cycle you're going to do the analysis, and you convert that to a percentage to subtract it from the other numbers.

Those are the three measured parameters, and now this is what you do with them. So, the calculated cladding oxidation during the LOCA shouldn't exceed the oxidation level from the unirradiated material minus the pre-accident corrosion. That's more or less the same prescription that we have right now.

The calculated time spent above any temperature should not exceed the time required to initiate breakaway oxidation at that temperature, and you've explored this, and so you've got that.

And then, finally, all of the calculations should be done with Cathcart-Pawel because we're using it as a time scale, not as a true measure of the oxide thickness, because it's the time at temperature that is important, not the amount of oxide that's growing on the surface.

So, now I'm back to about where I started with the summary at the beginning. The 17 percent number seems to work fairly well for the cladding that's currently in operating reactors, and the calculations have all been done with either Cathcart-Pawel or Baker-Just, so we're pretty sure that there are no situations that would violate the criteria that we're proposing.

I don't think any reanalysis would be needed. We've only relied on temperatures and times which are already calculated by the ECCS model, so there shouldn't be any impact on any of the ECCS models. The criteria applicable to small and large beak, it doesn't matter.

CHAIRMAN WALLIS: So these changes were then implemented in order to allow use of newer fuel, is that what they're for?

DR. MEYER: Yes. It ought to apply to all the zirconium-based alloys because we've looked at quite a number of them, not just the three that I've mentioned -- two varieties of Zircaloy, M5 and ZIRLO -- but also the Russian alloys, E110, E635, and several variants of each of those. And these criteria would catch them. You know, the ones that are going to breakaway, the rule would catch them and give you a very limited time that you could tolerate during a loss-of-coolant accident with those cladding types.

CHAIRMAN WALLIS: So then there might be some accidents where you wouldn't get to 2200, but you would get to 800 and you would exceed the oxidation level.

DR. MEYER: Right, the breakaway time. More likely it would be 950 or 1000, but that's absolutely correct.

When we discussed this with the subcommittee --

MEMBER POWERS: We've got to do something with Kress' intemperate comments.

DR. MEYER: You know I like that one, but let me just go down to the 1, 2 and the 3. The three main comments that I took away from that meeting -- and I did go back and look through the transcript -- was a question about whether the time-related criterion had been fully supported by data, a question about cooldown effects --

CHAIRMAN WALLIS: How many experiments do you need, and you showed us a few very sparse amount of data.

DR. MEYER: I'm going to talk about one and two. I've got another slide.

CHAIRMAN WALLIS: Oh, you do, okay.

DR. MEYER: And there was a question that Dr. Denning asked about the coupling between the changes in the criteria and the other 50.46 changes, and I don't plan to discuss that. I will just stick to the two technical questions here.

The first one was whether we had done enough work with regard to this time limit to prevent breakaway oxidation. At first, I misread the question because I thought there's an easy answer to this. We've done plenty of work to know that the phenomenon exists and that we need a limit for it. But as I tried to examine the details of this limit, I realized that we hadn't done enough in order to specify the limit itself.

So, what I've plotted here is the time in minutes to reach the onset of breakaway. I have one datapoint from the CEA plot that I showed before. I don't have anymore datapoints on M5. This slide is presumably for M5. What I do have is an old study from 1983 by Lystakoff on Zircaloy where he found for Zircaloy that the time to breakaway was minimum at 1000 degrees, and it didn't vary substantially as you went down or up in temperature. But what I also recognized is that for times out in this region, you run into the 17 percent limit. So, there's no need to explore the time to breakaway when you're going to be limited by the 17 percent, and this is where I was thinking about the five years or 50,000 miles, it's whichever one of these catches you first that's going to be limiting.

So, in fact, I don't think one is going to have to do a very exhaustive temperature study to get enough data to completely specify -- to adequately specify this breakaway time, but we clearly need more than one datapoint, and so we have taken this as a good question and we'll take more data.

CHAIRMAN WALLIS: You say time is, say, 100 minutes. This is a sudden precipitous event at 100 minutes?

DR. MEYER: It's fairly rapid.

CHAIRMAN WALLIS: It could be at 50 minutes, or 150, what is the certainty on this time? Is it something which is well-defined, or is it rather vague.

DR. MEYER: You remember the slide that I showed with the CEA data on it at 1000 degrees?

CHAIRMAN WALLIS: So it's pretty well defined.

DR. MEYER: It's slide 14, and it's rather well defined. We've seen the same phenomenon in the

Russian cladding, and it -- when it experienced breakaway, the hydrogen absorption picked up even more rapidly than this. So, it's fairly well defined.

It's also, I think, a very comfortable margin between times on the order of an hour or more, and the time that you would spend at high temperatures during an analyzed LOCA. So, I don't believe this is going to be -- present us with --

CHAIRMAN WALLIS: Are there any LOCAs that stay at this temperature that long?

MEMBER DENNING: Well, they would be intermediate kinds of LOCAs.

DR. MEYER: On my next slide, I have, in fact, a plant calculation here. This is just a plant calculation. It's one that Norm Wildman (phonetic) did. I don't know how typical it was, it was for -- it's a small break, a 2 inch cold leg break in, of all plants, Robinson, and you can see the -- it's holding up at high temperature for a fairly long time, but actually this decline down to 1100 or 1050 is quite significant in terms of the reduction in the rates of oxidation and oxygen diffusion. But the reason I put this slide in was to address the second question.

The second question was about cooldown rates, and the question about cooldown rates is probably the toughest question that we face right at the moment because it interacts with the experimental procedure, and let me try and explain how that goes.

Ideally, what we would like to do in an experiment which is measuring some diffusion-related phenomenon, you'd like to go up instantaneously to the temperature of interest -- say, 1200 degrees -- hold it there for an isothermal period of time, and take it down instantaneously, so that you don't have big heat-up and cool-down corrections to make in your parameters.

The problem occurs on the cooldown because in the plant it doesn't cooldown precipitously, and there is a metallurgical difference between a slow cooldown and a fast cooldown. What has happened here, at the high temperature you have now distributed oxygen into the beta phase and into the stabilized alpha phases, and because the temperature is high, the solubility in the beta phase is fairly high. If you quench it from that temperature and freeze in all of that oxygen in the beta phase, when you get back down near room temperature then the beta phase will been brittle.

If you come down slowly, the beta phase, as its solubility limit decreases, will start peeling off some more stabilized alpha to take that oxygen out of the beta phase, and you'll end up back at low temperatures with some low oxygen material which has ductility. So, the cooling rate is making a difference. We're seeing this difference in the test results. And at this point, I can only say that we're trying to figure out how to deal with it.

CHAIRMAN WALLIS: Well, my question was different. I said were there any plots which actually stated these high temperatures for as long as 80 minutes, and this one is only five minutes at this temperature.

DR. MEYER: This one -- I had the whole plot for this one, and this plant calculation stayed above --

CHAIRMAN WALLIS: So the real time zero is way back somewhere near real zero.

DR. MEYER: Right, this is just 300 seconds here. But I had the whole plot for this plant calculation, and the time above 1000 degrees was 2000 seconds.

CHAIRMAN WALLIS: Thank you.

DR. MEYER: So, we're struggling with the cooldown rate effect. Mike Billone, who is here today, is the principal investigator at Argonne. He's the one who's using this testing profile that's outlined on the figure. The French at CEA saw Clay using a different profile. The two laboratories are actively comparing data and trying to resolve the cooldown rate effects and figure out what is the best way to characterize the results. I think that's the end.

MEMBER POWERS: Thank you. Are there any questions for the speaker here?

(No response.)

Thank you, Dr. Meyer.

We will now turn to a presentation by Dr. Yang. I must say that the subcommittee benefitted very much from the generous contributions that EPRI made to our subcommittee meeting, bringing some of her best qualified staff to appear before us and share their technical views on subjects, as well as speakers from Westinghouse and fuel vendors.

DR. YANG: Thank you, Dana, for that nice introduction. My name is Rosa Yang. I work for Electric Power Research Institute, or EPRI. My job there, I'm responsibility for the Fuel Reliability Program, and today I'm speaking to you on behalf of the U.S. industry. The Fuel Reliability Program was formed in 1998 to address performance, regulatory and reliability issues. So, one of the working groups in this program specifically focused on regulatory issues like LOCA, and a little bit in terms of background is that this working group consists of utilities from both U.S. and international members. It also has active participation of the fuel suppliers, all the U.S. fuel suppliers, and Nuclear Energy Institute.

Interactions with the regulatory side, we go to NEI, and on research issues like LOCA and RIA, we work directly with RES. As Ralph said in his introductory remarks, that we, this program has been actively participating in the LOCA testing at Argonne since the late '90s -- actually 1998 -- and our contribution involved three different parts. The first part is we have been asked by NRC to provide a representative high burnout material, and throughout the years we have provided the high burnout H.B. Robinson lots at about 70,000 burnouts, also together with Nuclear Fuels we have provided BWRs cladding from reactor at 60,000 gigawatt days per metric ton.

In the earlier testing of the LOCA, those materials that were main prime materials for testing, we didn't want to sort of waste them, if you may, so we have actually had some slightly lower burnout, Zircaloy-4, that were available to us and shipped to

Argonne, so those actually were used in an earlier stage to sort of test out the equipment, the setup and everything. And next year, together with Areva, we will be providing some high burnout M5 cladding, so we've been actively providing the material from the U.S. plants.

We also -- I think another contribution we made is to provide analytical support for the design of and the qualification of the setup and the test protocols we made. What is important to point out is that we do perform independent evaluations of the results, so you will not be surprised that given the same data we may interpret and come to different conclusions.

So, at the July meeting, we were informed of the RES proposed approach for the LOCA criteria, and we have discussed among ourselves and the industry is supporting of the NRC overall objective with regard to the new LOCA criteria, and I'll get into specifics about what we like about the approach. We like the performance-based approach, and we expect the new criteria will allow for new cladding advances without need for rule exemptions each time a new cladding is introduced.

The industry has qualified support for

what was presented mainly because we think there is still some data to obtain. W would very much like to see that completion of the Argonne tests to confirm what was proposed. Also, we believe there is some work required in terms of clarification of what are relevant and representative test conditions. I will get into that a little bit more. I think Ralph -- Dr. Meyer -- has alluded to that earlier.

And also, as we go into the rulemaking, we'd like clarification of the application details.

So, what we like about the proposal, the proposal is consistent with the current regulation. And we agree with Ralph, it would require minimal change to implement the new criteria into the current LOCA licensing methods. And the rule is relatively simple and can be implemented quickly.

We also think that the rule is -- what is proposed is conservative. As indicated and discussed earlier, we believe the appropriate yardstick is really surviving the quench, not post-quench ductility. Post-quench ductility represents significant conservatism, and given the type of regulation we're dealing with, we think there is appropriate conservatism here to protect public health and safety. So, although we think the surviving quench is the correct yardstick, we agree with the post-quench ductility theory.

As I indicated earlier, the performance-based criteria allow for easier transition to new cladding type. Some of the data that we believe should be obtained as quickly as possible at Argonne that would confirm some of the discussion here is sort of in the order of priority listed here. The first one is to conduct the ring compression test, as Ralph described earlier, a sample of relevant hydrogen content. What has been performed up to now is at 600 ppm. We want some relevant concentration performed with quench.

Also, the two type of cladding that are mostly in use in the country right now, and pretty much around the world, is ZIRLO and M5. We'd like to see the irradiated ZIRLO and M5 being conducted as quickly as possible.

MEMBER POWERS: Let me interrupt you and ask, do you foresee this to be a phenomenon, ZIRLO and M5, being the predominant forms of cladding for the next 40 years?

DR. YANG: Forty years?

MEMBER POWERS: Well, a license renewal that will carry most of the plants in the United

States out for another 40 years, so I think we have to think in those terms at the minimum.

DR. YANG: Well, this question is probably better answered by the fuel suppliers. Let me give you my own reaction, which is just off the top of my head reaction. I do know there are good advanced alloys being developed, and I also know, being in this business for a long time, it takes quite a while to introduce any new material. So, it probably will take at least another 10-15 years before any new material is commercially used. So, I think it's easier to answer for the next 20 years, yes. For the next 40, I hope we will have materials which are even better.

MEMBER POWERS: You gave the right answer. Go ahead.

DR. YANG: The last one is interesting just to confirm the LOCA behavior. In terms of setting the criteria, the last one may not be as urgent as some of the earlier tests. And some of the other details -- and these are really in terms of questions, and I believe we can address those together later on. So, I think just for the record I would like to say page 6 are some of the issues that I think need to be addressed in either the rules or the Reg Guide.

So, in conclusion, the industry is supportive of the NRC overall objective with regard to the new LOCA criteria. We think that the rulemaking should proceed, and we'll continue to work with the NRC on the test at Argonne, and as you know, there are other LOCA tests around the world, and I think we need to continue to monitor the results of those tests and analyze the results from both Argonne and those other programs, and to confirm that, indeed, the proposed criteria is a good one. Thank you.

MEMBER POWERS: Are there any questions for the speaker?

(No response.)

Dr. Yang, thank you.

Now we'll hear from a third partner in this overall effort. Roger Reynolds, Chief Technology Officer for Framatome, will speak to us now.

MR. REYNOLDS: I'll be brief. I have two objectives. One is to be clear about what Framatome Areva's position is with respect to the proposal, and to make sure there's no confusion because we were not totally positive during the subcommittee meeting, but we were confused about what the proposal was then, I want to make sure there's no confusion today.

As Rosa described, Framatome's been

involved with EPRI, with Progress Energy, and with Dominion, in cooperation with the NRC to provide both irradiated an unirradiated cladding samples for the research program. We've also provided test data from our cooperative research with EDF and CEA as a way to try to understand some of the data that we've seen at Argonne.

Prior to the subcommittee meeting in July, our expectation was that the proposed rule was going to be based on what we considered to be a complicated embrittlement correlation, and our view at the time is that we should not proceed with a rulemaking based on that proposal primarily because of a lack of data, but a much simpler proposal was presented, as Ralph described today, and that establishes a reasonable approach to assuring safety and responded to insights gained through the recent Argonne tests and other research both in CEA and Japan.

Along the lines that Ralph has presented, it provides a broadly based acceptance criteria, that a performance base without excessive conservatism, conservative but we don't believe it's excessive. Through surrogate of corrosion, we think the significant fact that burnup of the hydrogen accumulation is accounted for, specifically calls out the time and temperature criterion so we can establish a core cooling. There's a qualification made for the introduction of new alloys that I completely agree with what Rosa said, takes 10 or 15 years to introduce new alloys. M5 will be the BWR product for probably another 10 to 15 years, and then it will be something else.

The proposal, as Ralph represented, is similar to the current practice in that we take into account the pretransient oxidation. So, if the rule should not be onerous to implement, be relatively simple with no changes in models required, there's no major issue in the calculations that we'd have to do.

MEMBER POWERS: It does seem to change from the Baker-Just to the Cathcart-Pawel.

MR. REYNOLDS: True.

MEMBER POWERS: So there is some change in modeling.

MR. REYNOLDS: But it's relatively simple to implement, it's a subroutine. We agree with EPRI that ductility is not necessarily the metric, that quench survival tests are adequate, which would be less conservative than the rule as we understand it. NRR has agreed with our data previously with the 2200 at 17 percent based on quench survival tests that we provided, that report was approved in 2000, but the rule as proposed is more conservative than this.

We don't think there's any safety issue driving the schedule, so there's no huge rush to change things, so I think we could do it at a measured pace. We support totally the idea of completing the planned test and the current program so that those data and other worldwide data can inform the rule over the next year. And the bottom line is that we support the industry position, we support RES position to move ahead with the rulemaking as proposed.

MEMBER POWERS: Thank you. Are there questions for the speaker?

MEMBER DENNING: Yes, I have a question. As you see it, the value of making the rule change has to do with future simplicity of introducing new cladding materials which is a long way down the road. Is that basically what you see the reason why we would move forward?

MR. REYNOLDS: That's a key aspect.

MEMBER POWERS: We have a problem right now. Yes, the rule is written for Zircaloy and ZIRLO, as it is written now, so that anybody who doesn't use that has to file for an exemption.

MEMBER DENNING: Like M5 right now?

MEMBER POWERS: Yes, has to come in for an exemption.

MR. REYNOLDS: For every relay.

MEMBER DENNING: For every relay?

MEMBER POWERS: It's every core reload. You don't get one to last forever, it's every core reload.

Any other questions for the speaker?

(No response.)

Well, thank you all very much, it's a very useful, very succinct presentation. I will again indicate that I think we had an exceptional subcommittee meeting, exceptional for the technical quality of the presentations and the breadth of material covered. In that meeting, we also covered the latest on the reactivity insertion accidents, and I hope they'll bring the staff back to discuss that at sometime in the future. And with that, I will turn the meeting back to you, Mr. Chairman.

CHAIRMAN WALLIS: Thank you. Well, we have made up the time we spent, overspent, or whatever, we didn't lose the time. We overspent our time budget and now we have made it up, so we're ahead of time. Therefore --

MEMBER POWERS: I will note that that's

been consistently done by one group of presentations throughout the meeting.

CHAIRMAN WALLIS: It doesn't correlate at all with my absence. That hypothesis is now defunct.

MEMBER POWERS: We will note that we did not make up as much with you present.

CHAIRMAN WALLIS: So, on that note, we will take a break until quarter to 6:00, and we don't need the Reporter after that time. We will go to work on our letters.

(Whereupon, at 5:27 p.m., the recorded portion of the meeting was concluded.)