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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

539TH MEETING

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WEDNESDAY, FEBRUARY 1, 2007

**VOLUME I**

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

MEMBERS PRESENT:

WILLIAM J. SHACK, Chairman

JOHN D. SIEBER, Vice Chairman

SAID ABDEL-KHALIK, Member

GEORGE E. APOSTOLAKIS, Member

J. SAM ARMIJO, Member

SANJOY BANERJEE, Member

MARIO V. BONACA, Member

MICHAEL L. CORRADINI, Member

THOMAS S. KRESS, Member

OTTO L. MAYNARD, Member

DANA A. POWERS, Member

GRAHAM B. WALLIS, Member

STAFF PRESENT:

ZENA ABDUALLY
WILLIAM H. BATEMAN
GARY HAMMER
CORNELIUS HOLDEN
MICHAEL JUNGE
RALPH LANDRY
TIMOTHY R. LUPOLD
RALPH MEYER
BOB RADLINSKI
TANEY SANTOS
TED SULLIVAN
JENNIFER L. UHLE
SUNIL WEERAKKODY

ALSO PRESENT:

JOHN ALVIS
MICHAEL C. BILLONE
BERTRAND DUNNE
NAYEM JAHINGIR
CHRISTINE KING
ALEX MARION
ODELLI OZER
JIM RILEY
MIKE ROBINSON
GLENN WHITE

A-G-E-N-D-A

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

(8:33 a.m.)

CHAIRMAN SHACK: The meeting will now come to order. This is the first day of the 539th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the committee will consider the following: five percent power uprate application for Browns Ferry Nuclear Plant Unit 1; license renewal application for the Oyster Creek Generating Station; development of trace thermal hydraulic system analysis code; and preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the designated federal official for the initial portion of the meeting. We have received written comments from Mr. Richard Webster from the Rutgers's Environmental Law Clinic and Senators Robert Menendez and Frank Lautenberg and Congressmen Christopher Smith and Jim Saxton regarding the license renewal application for Oyster Creek.

We have received requests from Mr. Odelli Oser from EPRI and Mr. Alex Marion of NEI for time to make oral statements regarding LOCA criterion for fuel cladding materials and the Wolf Creek pressurizer weld flaws respectively.

In addition, Mr. Richard Webster requests time to make oral statements regarding the Oyster Creek license renewal application.

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 they can be readily heard. I will begin with some items of current interest.

Members should note that we're scheduled to interview two candidates for the ACRS during lunchtime today.

Mrs. Sherry Meter who has been with the ACRS for 11 years will be leaving to join the Commission staff on February 5th. She has made numerous outstanding contributions to support a ACRS and ACNW activities. She was an exceptional technical secretary to the committee. Sherry's enthusiams, patience and dedication to support the committee during the preparation of the reports was very much appreciated. She has been very pleasant to work with, and we will miss her humor and hard work. Thank you and good luck, Sherry.

(Applause.)

CHAIRMAN SHACK: Ms. Zena Abdulahy has joined the ACRS staff as a senior staff engineer on January 22nd. She joined the NRC in 1995 as a participant in two-year nuclear engineer intern program which included required course work, onsite plant training, and rotations to different departments within the NRC where she gained a broad knowledge of NRC activities.

Since 1998, she has been with the Division of Safety and Analysis of NRR where she worked as a technical reviewer in the BWR and Core Performance Group at increasing levels of responsibility. She utilized her extensive background and experience in the areas of reactor neutronics and thermal hydraulics to prepare safety evaluations and review and approve plant license amendment requests. Ms. Abdulahy has a BS in mechanical engineering from the University of California Davis and an MS degree in fluids and energy systems from the University of Maryland at College Park.

I should also note that our colleague, Graham Wallace, will not be joining us for this meeting. He's recovering from a severe cold and didn't make it out of the cold depths of Vermont and New Hampshire.

We'll start this morning with our work on the -- or the review of the power uprate for Browns Ferry Nuclear Plant Unit 1 and Dr. Bonaca will lead us through that.

MEMBER BONACA: Good morning. On January 16 and 17, we met with the applicant and the staff to review the application of Browns Ferry 1 for a five percent power uprate. Much of the work that was submitted to -- as a basis for this uprate has been to perform at 120 percent power, so I think throughout this presentation, it will be important to keep in mind which parts are supported at 120 percent power and which are specific to 105 percent.

During the meeting with the licensee and the staff, some issues related to a number of scenarios for which TVA is asking for NPSH credit came up, and we asked for further clarification and information that I think the licensee and the staff are going to provide today to questions of the committee. These are some new scenarios we have not previously seen for previous plants.

With that, I think I'll -- the introduction anyway -- I'll turn the meeting to the staff and we can proceed with the presentations.

MR. McGINTY: Thank you, Mario. The

intent of this briefing today is, much as you said, to provide some clarifications regarding several ongoing issues. We're also going to discuss the methodology used for the Browns Ferry power uprate submittal and the NRC staff review and provide a status of the three applications. By the way, my name is Tim McGinty. I'm the Deputy Director for Operating Reactor Licensing in NRR. I should have introduced myself first. My apologies.

As a result of this briefing, it is our desire that the ACRS will write a letter to the Commission confirming the staff safety evaluation finding regarding the 105 percent uprate and selected 120 percent review areas and outlining the additional information needed to be presented to the ACRS later this summer in support of these two 120 percent extended power uprate submittals. In that regard, we have an advantage in gaining the insights from the committee, and we look forward to gaining as much as possible in that regard.

As a way of background, the Browns Ferry Units -- and to set the stage, and I'll quickly go through these -- it's a BWR/4 design with Mark I containments. Unit 1's operating license was issued in 1973, Unit 2 1974, and Unit 3 in 1976, and they're rated corth power levels. For Units 2 and 3, they're licensed currently to operate at 3458 megawatts thermal, while Unit 1 remains licensed at the initial licensed thermal power of 3292 megawatts thermal.

To briefly go through some of Browns Ferry's history, in March of 1985, all three Browns Ferry Units were voluntarily shut down by TVA to address performance and management issues. Following the shutdowns, TVA specified corrective actions which would be completed prior to restart. All three Units retained their operating licenses during their respective long-term shutdowns. The restart efforts for Units 2 and 3 were both approximately five years in duration with Unit 2 restarting in May of 1991 and Unit 3 in November of 1995.

The Board of Directors for TVA decided to restart Unit 1 in the 2002 timeframe, and soon thereafter discussions began with the staff to address their intent to not only restart Unit 1 but renew the operating license for all three Units at extended power uprate conditions. Thus in June of 2004, the staff received the extended power uprate request, but issues with the steam dryer review have resulted in the staff being unable to complete their review thus far.

In the interim, TVA requested a two-step approach to support restart of Unit 1. This consists of a 5 percent increase and then the remaining 15 percent after the steam dryer issues are resolved. And it mirrors Mario's earlier comment that throughout these proceedings, we -- clarity in that regard with respect to the safety evaluation and what was evaluated is essential and we'll try to achieve that.

For a current update regarding the steam dryers, TVA has not yet provided all the information needed to support the steam dryer review. As a reminder, in the fall of 2006, TVA shut down Browns Ferry Unit 2 to instrument the main steam lines to gather actual operating data. This data would then be used by the licensee to support a revised stress analysis report and establish appropriate monitoring parameters during extended power uprate power ascension.

Just on January 25th, the staff sent a letter to TVA requesting a summary of the proposed actions going forward to resolve the steam dryer issues and a schedule. We are in receipt of TVA's response. I understand that we got it today. Ongoing discussions with -- it's my understanding that the information on the steam dryer analysis will be available by April 2nd.

With that said, I'd like to turn over the presentation to Eva Brown.

MS. BROWN: Thanks, Tim. My name is Eva Brown and I'm the Lead for the Browns Ferry power uprates. For the Unit 1 uprate to 105 percent, original licensed thermal power, a higher steam flow was achieved by increasing the reactor power along specified control rode and core flow lines and increasing reactor operating pressure approximately 30 psig. This increase in steam flow supports increasing the electrical output of the plant. All of the Browns Ferry uprates were reviewed using the same guidance and process -- let me say it one more time -- all of the Browns Ferry power uprates were reviewed using the same guidance and process. The guidance for such a review is provided in our review standard RS001 while guidance on approach format and technical aspects are also provided in the NRC approved General Electric Power Uprate Topical Reports. Just as a mention, the previous BWR uprates, like Vermont Yankee, were constant pressure power uprates, and this is under a different guidance under the GE Extended Power Uprate Licensing Topical Report, or ELTR1. You may hear me say that interchangeably.

As you're aware, the committee recommended that a standard review plan be developed for our uprates to ensure that the potential for synergistic effects are covered, any reduction in the safety margin is assessed, and a more standard review was conducted. The staff evaluated the EPU application and review process in light of the ACRS recommendation and concluded that increased standardization of the staff's review processes could enhance the consistency, quality and timeliness of the reviews.

A review standard was developed to provide a clear definition of the review scope, references to existing review criteria and provide a template safety evaluation. This effort resulted in a clear definition of the review scope for the EPU and a central listing of existing review criteria allowing the staff to more easily identify their criteria applicable to EPUs and complete the reviews more effectively and efficiently.

The staff provided a draft of the standard in SECY 02-0106 which was recommended for issuance by the committee in September 2003. The committee found that the review standard provided a clearly defined review scope, provided a reference for determining the existing review criteria and provided a standardized safety evaluation template.

A plant seeking a power uprate consistent with the ELTRs is expected to request an amendment to the license consistent with the considerations that govern the current license. The submittal is expected to address several licensing considerations. All safety aspects are evaluated, including the nuclear steam supply and balance of plant systems. The evaluations and reviews are based on the plant's licensing criteria, codes and standards applicable to the plant at the time of the submittal and the evaluation and analysis performed using NRC approved methods for the URSAR accidents and transients affect ad by the power uprate. The reviews of the NSSS and balance of plant systems, structures and components were evaluated to ensure continued compliance to the codes and standards applicable to the current licencing basis and the functional and regulatory requirements specified in the UFSAR and the applicable reload license.

Additionally, all plant structures, systems and components are reviewed to ensure there's no significant increase in the challenges and the existing environmental regulations are met. The staff's review of the Browns Ferry uprate submittals verify that these assumptions were made valid.

The appendices of the EPU Topical Report, or ELTR1, describe the methodology and initial assumptions. As the licensee submittal was performed consistent with the topical report, assumptions are the same unless specifically indicated otherwise. So if we look at the low pressure safety systems, we find that the expectations and assumptions come from Appendix J of the ELTR.

For the low pressure system such as core spray and the residual heat removal system, the hardware is not affected. The ejection set points remain unchanged. The flow rates are not increased as a result of the uprate, and the existing shutdown cooling flow rates do not need to be increased. These evaluation results provide confidence that the LOCA and shutdown requirements were met.

Another example is the CRD or control rode drive system. The previously approved generic review allowed the staff to confirm that the topical report assumptions were met. In this case, the submittal was expected to discuss the system had been evaluated for the affects of increased pressure on scram time and address whether the system performance remains independent of parallel. In this case, the affect of the uprate is as expected, a result of pressure increase.

However, the resulting affect is a slight reduction in scram times. The slightly higher increase loads on the CRD mechanism is found acceptable since original design accounted for these higher pressures. As the licensee submittal confirms, these aspects are satisfactorily met. The staff found this system acceptable for operation at uprated conditions.

As discussed in more detail with the subcommittee, a considerable portion of the Browns Ferry submittals, the generic assumptions and results of the ELTR were confirmed as applicable for the applications. This provided for efficiencies and review due to having an application consistent with a previously defined scope and set of assumptions. Appropriately applying approved methodologies with a common expectation for evaluation results.

The staff's review of the licensee's application found that a significant portion of the review of the submittal followed the guidance and processes for the EPU Topical Reports discussed previously. The remainder of the review focused on plant unique aspects and emerging generic technical issues. We will briefly discuss some of these later in the presentation.

At this time, I'm going to turn the presentation over to TVA for their comments.

MR. BHATNAGAR: Good morning. My name is Ashok Bhatnagar. I'm the Senior Vice President of Nuclear Operations with TVA Nuclear. Since October, I've been predominantly at Browns Ferry in order to support the restart effort and integrate Unit 1 into the rest of the operating fleet. We appreciate the opportunity to be here today to talk about the power uprate of Unit 1 at Browns Ferry. I want to thank the subcommittee and the committee for the scheduling changes that were needed in order to support the restart. We do appreciate that.

The restart at Unit 1 is nearing completion. The reactor building, including the drywell work, is essentially complete with the major focus of the project now shifting over to the balance of plant completion of those systems. Additionally, a significant amount of component and system testing is in progress on the remaining portions of the plant. With the reactor building work essentially complete on time, we were able to move up the Unit 2 refueling outage that was coming up about three weeks from our original schedule.

What happened is if we had stayed on that original schedule, the restart of Unit 1 would have essentially been at the same time as the startup of Unit 2 coming out of this refueling outage. As a conservative measure, we decided not to do that. We decided to separate those two activities so the operators could focus on both of those critical functions that they had to perform.

We have completed many restart reviews and self assessments. The action list has been developed. It's a single action list of all the necessary actions to get to restart. Those actions are in progress and will be completed prior to restart. Additionally, as reviews are ongoing, we have additional restart readiness reviews that are in our schedule and those will be completed prior to restart.

Operations now fully controls the plant, all three Units, and they're using the same standards as we have on the operating fleet. The Operations group has been fully staffed and trained to be ready to restart the Unit 1 and also to complete the remaining testing on Unit 1.

A lot of work has taken place over the last four and half years, but there is still work left to go. We have a couple of very large pieces of work left to go in the integrated leak rate test and the reactor vessel hydro. But I do want to tell the committee we have the time to do this work correctly and do it right.

With that, let me turn the presentation over to Bill Crouch.

MR. CROUCH: Good morning. My name is Bill Crouch. I'm the Site Licensing Manager at Browns Ferry. On page four of your handout, the five percent uprate that we're doing for Unit 1 will bringing it, one, to the point that it is operating very similar to the power uprates we've already done on Units 2 and 3. The plants will be operating with the same steam flow, same feed flows. Everything will be the same as what's currently operating on 2 and 3 so that we can maintain the similarity. And then when we progress on up to an EPU condition in the future, once again, that'll be maintained similar.

MEMBER BONACA: Bill, let me ask you a question regarding that. Now for Unit 1, you modify the impellers in the feed water pumps from the same pumps and the booster pumps, right?

MR. CROUCH: That is correct.

MEMBER BONACA: So you did the same thing for Unit 2 and 3?

MR. CROUCH: On the upcoming outage for Unit 2, which starts here in just a few days, we'll be installing the same pumps and motors and everything.

MEMBER BONACA: The same. Okay. And so now insofar as the piping that you have replaced, the configuration is the same?

MR. CROUCH: The configuration is the same. We -- and I'll get to that a little more in detail, but when we went through the Unit 1 restart effort, we replaced a tremendous amount of piping in the buildings, both out in the turbine building and the reactor building. When we replaced them, we replaced them with enhanced materials, but we went back with the same geometry so that the flow characteristics would be the same.

MR. BHATNAGAR: If I could make one clarification? The high pressure turbine and the modifications to the steam dryers will take place later on Unit 2. If you put the high pressure turbine in now, you actually lose megawatts because you open up steam paths which we don't need until we have EPU conditions. So we would do that in a future outage.

MR. CROUCH: Those two --

MR. BHATNAGAR: On Unit 2, those two

pieces of work will not take place during this outage.

MEMBER ARMIJO: Do you plan to use exactly the same water chemistry in Unit 1 as in Units 2 and 3?

MR. CROUCH: I believe it's exactly -- yes.

MEMBER ARMIJO: Specifically the hydrogen-water chemistry?

MR. CROUCH: Yes, and Noble Chem.

MEMBER ARMIJO: Okay. At the end of the cycle?

MR. CROUCH: Well, Noble Chem, you can't inject it --

MEMBER ARMIJO: Right.

MR. CROUCH: -- right at the beginning, you have to have a --

MEMBER ARMIJO: The end of the cycle?

MR. CROUCH: -- pre-conditioning period.

MEMBER ARMIJO: Right.

MR. CROUCH: And then somehow later on, we'll inject Noble Chem.

MEMBER ARMIJO: Okay.

CHAIRMAN SHACK: So you'll be running under a modified hydrogen-water chem? You'll still aim for the minus 230 corrosion potential even without the Noble Chem?

MR. CROUCH: Robert or?

MR. PHILLIPS: My name is Robert Phillips. I'm with TVA. I wanted to make sure I heard the question again.

MR. CROUCH: Will we be operating with the same minus 230 criteria on Unit 1 as we are on 2 and 3 even though we haven't had Noble metals injection yet?

MR. PHILLIPS: That's what the current plans are is to do that, yes.

MR. CROUCH: Okay.

CHAIRMAN SHACK: So you'll just inject enough hydrogen to do that and you can live with the shine?

MR. CROUCH: Yes.

MR. PHILLIPS: Yes.

MR. CROUCH: Thank you.

CHAIRMAN SHACK: Okay.

MR. CROUCH: As Eva pointed out during her opening portions here, when we started the Unit 1 project, it was our intention at that time when we restarted the Units to go straight to the 120 percent. As she talked about, we've had some questions on the steam dryer analyses, so we're backing up and performing this analysis -- this uprate for the first five percent, but the analyses that were done to support this five percent, we've utilized for the most part the analyses that were done to support the 120 percent. They are bounding analyses that envelop the 105 percent condition. There's a few analyses that we have redone at 105 percent specifically because you cannot use the higher power analyses to support the core itself. So we've redone the supplemental reload analysis and the specific core patterns and all that that does with the core analyses to the 105 percent conditions.

When we restart Unit 1, we'll have effectively the same licensing basis as 2 and 3, meaning we'll have the same five percent uprate. We will have implemented all the same programs on Unit 1 restart as what we did for 2 and 3. We will have implemented all of the upgrades on 1 that we previously installed on two and three so the licensing basis will be the same. It's not identical. There's a few small things that are slightly different, but they don't affect the operation of the plant per se.

MEMBER BONACA: But now Unit 2 and 3 have Areva fuel, right?

MR. CROUCH: Unit 2 and 3 have Areva fuel.

MEMBER BONACA: Unit 1 has GE fuel.

MR. CROUCH: GE fuel.

MEMBER BONACA: So there is a difference. I'm trying to understand how you're going to -- I mean the path to go to 120 percent power for Unit 2 and 3 has to be different than the one for Unit 1 or are you --

MR. CROUCH: That's correct. It is slightly different in that there were analyses that were part of the Unit 2 and 3 submittal that were specifically for Areva fuel, and there's analyses in the Unit 1 submittal that was specifically for GE fuel at 120 percent.

MEMBER BONACA: The reason why I'm asking that question is, you know, 120 is going to talk about it later. I mean right now it's 105. But one question I had during the subcommittee was your analyses of record for Unit 1 were based on old methodology of the 1970's, I mean -- and you have used the SAFERJESTR, I think, to analyze now the power uprate, I mean the 105 percent?

MR. CROUCH: That is correct.

MEMBER BONACA: And the question I have is did you re-perform your regional analysis also with SAFERJESTR or how did you handle that? I mean --

MR. CROUCH: For the 105 percent condition?

MEMBER BONACA: The ELTR1 requires that you -- first of all, if you change methodology, first of all, you run the same analyses with the new methodology, okay, to verify what the effects of the methodology is on your licensing bases. And then you do the uprate which is, you know, you run now the analyses at five percent above that. Did you do that or --

MR. CROUCH: Yes. We have analyses for --

MEMBER BONACA: Because you mentioned to me during the subcommittee that you did that for Unit 2 and 3.

MR. CROUCH: We have analyses at 105 percent for GE fuel and for Areva fuel, and then we have analyses at 120 percent for GE fuel and Areva fuel.

MEMBER BONACA: The question was do you do the analyses at 100 percent?

MR. CROUCH: At 100 percent, no. We've never done any 100 percent analyses with the SAFERJESTR code. On Units 2 and 3, we transitioned to SAFERJESTR at just about the same time as we went to 105 percent. We never went back and re-ran the 100 percent analyses on SAFERJESTR.

MEMBER BONACA: I thought that the ELTR1 requires that you do that, but anyway I have to look at it. Does the staff know about that?

MS. BROWN: Yes, sir. As part of the EPU uprate review, Projects issued a letter, I think, in the late 90's early 2000. What the staff ends up doing is asking the licensee to actually submit the core, so the staff does a core -- a cycle specific review for the first uprate core, in this case for Units 2 and 3 as well as Unit 1, to address the issues with methodologies and to ensure that the thermal limits and stuff are acceptable and regulatory --

MEMBER BONACA: Because I think that's important because, I mean, you want to separate the effects of the methodology from the effects of the uprate.

MS. BROWN: Yes, sir. So we do a plant specific, cycle specific review for the first uprate core.

MEMBER BONACA: Who did that?

MS. BROWN: We did that for Unit 2. That's --

MEMBER BONACA: We? I mean the staff did that?

MS. BROWN: Yes. We did take a look at the Unit 2 core, and we'll be getting information on Unit 3 as soon as it becomes available for the 120 percent.

MEMBER BONACA: Why is it applicable to Unit 1?

MS. BROWN: I'm sorry?

MEMBER BONACA: Why is it applicable to Unit 1? I would like just to have a straight answer.

MS. BROWN: Oh, I'm sorry. We reviewed the Unit 1 core plant specific for cycle seven as well. So we did a plant specific, cycle specific review for each core for a power uprate.

MEMBER BONACA: So you performed the calculation. I thought that the licensee does those calculations?

MS. BROWN: We performed a review. I won't say that we performed a complete --

MEMBER BONACA: We heard that it wasn't done for Unit 1.

MR. THOMAS: This is George Thomas from Reactor Systems Branch. We did independent calculations for LOCA for Unit Number 1. But when you say calculations, you don't do all the calculations. You only do very few calculations like LOCA calculations.

MEMBER BONACA: So you're happy about the way that the licensing basis for Unit 1 has been modified for the regional one to the current one?

MR. THOMAS: Yes.

MEMBER BONACA: Intermediate steps are there?

MR. THOMAS: Yes. Actually, they provided the calculation for 105 as well as 120 for LOCA and that was --

MEMBER BONACA: Yes. I was asking about 100 percent.

MR. THOMAS: Right.

MEMBER BONACA: I wasn't asking about 120. I know you did that. I was asking about, you know, did you supply the affect on methodology. And I really, from the mixed answers I got, I don't understand.

MR. CROUCH: There -- when we did the five percent uprate on Units 2 and 3, we did not at that time go back and re-analyze 100 percent with SAFERJESTR, because we had already transitioned -- like I said, we did them both at the same time, but we -- I know -- I remember back from that timeframe, because I was involved in it, we did look at the answers from 100 percent with the old, was it, SAFE reflow, whatever the codes were and compared them -- looked at SAFERJESTR. We did look at that, but I don't know that --

MEMBER BONACA: The reason why I ask the question is because the change in methodology was so substantial from what was used in the early 70's to what -- SAFERJESTR -- that -- it's a heck of a difference, and typically you want to separate the methodologies effect or results from the uprate -- the actual power uprate. You want to separate them so you can understand where the effects are coming from. And so -- well, let's proceed now. I think we understand the situation.

MR. SIEBER: Maybe I could ask a question that would help clarify this for me. Some utilities do their own reload safety evaluations. Others rely on the fuel vendor. Does TVA doe their own reload safety evaluations or do you rely on your fuel vendor?

MR. CROUCH: The fuel vendor performs them for us and we perform an independent review of them.

MR. SIEBER: Okay. So now at Browns Ferry, you're going to have two different fuel vendors using two different sets of codes to analyze basically identical plants?

MR. CROUCH: Is that the case?

MR. SIEBER: Thank you

MEMBER ARMIJO: I'd like to get a confirmation now. Browns Ferry Unit 1 core is loaded for 120 percent power --

MR. CROUCH: Correct.

MEMBER ARMIJO: -- but you're only going to utilize it at 105 percent. Now is there anything unique or special related to the operation of the core with that kind of loading?

MR. CROUCH: We'll have Greg Story answer that. He's our BWR Fields Manager.

MR. STOREY: Greg Storey, TVA. I understand the question is what are we going to different at 105?

MEMBER ARMIJO: Yes.

MR. STOREY: We have a specific operating strategy, control rod pattern strategy that we have developed for 105 percent operation.

MEMBER ARMIJO: And that's all you have to do?

MR. STOREY: Yes. And the reload licensing, as Bill had indicated earlier, has been redone based on 105 as well.

MR. CROUCH: You will obviously affect

fuel --

MEMBER ARMIJO: Yes. He --

MR. CROUCH: -- patterns and stuff but we have analyzed it specifically for 105 percent condition.

MEMBER BONACA: Okay. That's --

MR. CROUCH: If there's no other questions then let's turn to page five. And I'm not going to go over this whole history here. Eva's already touched on it. A couple of things I do want to point out -- that they've asked that we make sure we clarify them here. There is somewhat of a misperception in that Browns Ferry Unit 1 restart. We are not starting back up from the fire in 1975. That fire occurred. We did restart the Unit back in '76 to '77, and we ran for a few more years before we shut them down in 1985.

As we pointed out, in 1998 and 1999, we did uprate Units 2 and 3 to 105 percent, so we have several years of operating experience at that condition for the two other Units that are sitting right beside Unit 1.

MEMBER POWERS: When were your piping replacements done on 2 and 3?

MR. CROUCH: When?

MEMBER POWERS: Yes.

MR. CROUCH: Some of them were done -- for the restart efforts of each of those, some of the piping replacements were done later. For example, FAC piping replacements on those other Units, we stage those by outage, so we'll go in and perform a portion during one outage. Then we'll go into the next one so that the big major NSSS-type piping replacements were done during restarts. Back piping replacements had been done during subsequent outages.

MR. BHATNAGAR: And some of the fire protection piping also was done during the operating period after recovery, two large pipings.

MR. CROUCH: In 2002, we initiated activities to restart Unit 1, so if you turn over to page six there, the question that's come up is well, we don't understand exactly how all this stuff integrates together. And so we had lots of different licensing actions going on as part of Unit 1 uprate -- as part of Unit 1 restart. And as I mentioned, when we started the process of restarting Unit 1, it was our intention to go to straight to 120 percent. We were also doing a license renewal at this same time. So when we did the license renewal evaluations internal to TVA, they were all done at 120 percent and fed into the license renewal application. But the license renewal application was only for 100 percent, because the NRC staff did not want to infer that they were approving 120 percent through the license renewal application. But all the evaluations were done at 120 percent.

Similarly, as I said, we started out with the intention to go straight to 120 percent, so all the calculations and design work that was done for restart was done at 120 percent, which bounds the 105 percent condition. We were also in the process of implementing all of what we called out special programs or our regulatory programs, the commitments. These were doing things like the EQ program, IGSCC, Appendix R. There's a list of about 30 special programs we went through.

We also went through all the generic letters and bulletins and all that, the different regulatory documents. When we responded to each one of those for Unit 1 restart, we did the calculation or the design at 120 percent, so it was done at a bounding condition feeding into restart. Then when we decided to back up and go to 105 percent, we evaluated which of these documents would have to be represent only 105 percent. We talked to GE. We looked internally. We did internal reviews. And we concluded that the only documents that specifically had to be revised were the fuel-related documents that we just talked about.

Turning on over to page seven then, a little bit more of the history. Once again, I'm not going to do all the points. As Tim pointed out that we do intend to give the steam dryer analyses in early April. Then we also plan to start up in the spring of '07 for Unit 1, and then hopefully transition on off to EPU in the fall of '07 once all the dryer analyses and the other aspects have been reviewed.

Page eight, just to give you an idea of the magnitude of what we've done for the Browns Ferry Unit power uprates, we performed a lot of different modifications, probably more than what most people have performed. And the reason we did that was not only did we want to do an uprate, we wanted to add margin back into the plant. So I'm going to start over on the left-hand side of the slide here and touch upon just a few of the things we've done.

The reactor is shown in red there and internal to the reactor, we have already performed modifications on the Unit 1 steam dryer to beef it up, to make it more robust so that it will be able to handle the 120 percent steam flow. We also performed various modifications inside the vessel such as increasing the jet pump sense line clamps so they'll be able to handle the flow induced vibrations.

MEMBER CORRADINI: May I ask just a question? Maybe you said this in the subcommittee and I don't remember writing it down. Are these modifications identical to what's occurred in 2 and 3?

MR. CROUCH: They have not been performed on 2 and 3 yet.

Moving on to the right a little bit, for the high pressure turbine, as Ashok mentioned, we have -- we will be replacing on Units 2 and 3, and we have already done on Unit 1, replaced the high pressure turbine itself to get the extra work out of the steam as it comes through the system. The turbine is tuned for the specific steam flow and so if you're -- we're operating at a lower condition, like 105 percent, you actually do have a slight de-rate on your megawatts electric coming out. And so that's the reason why for Units 2 and 3, right now, we're not going to do the high pressure mod until we get the EPU approved. We will do that subsequent once we get the approval.

Moving on over, we have rewound the generator to increase it's megawatt output. The Unit 1 generator has been rewound so we'll have a 1280 megawatts output. We added margin back into the plant through the condensate feed water side. We've replaced the condensate booster, the condensate pump impeller and the motor. We've replaced the entire condensate booster pump. We've replaced the flow path inside the reactor feed pumps and the reactor feed pump turbine so that previously the plant, as it was designed, it had three trains of pumps, and each pump was approximately about a 40 to 45 percent capacity pump. We replaced these with pumps such that we will have better than three 50 percent capacity pumps.

What that will do for us is in the event that a single pump trips, we will be able to continue to operate the plant at full 120 percent power without having to de-rate or run back or anything --

MEMBER BONACA: Run back. Okay.

MR. CROUCH: Previously if we tripped a pump like that, we would have to run back to approximately, what is it, 68 percent or something like that, so this will add margin to the plant to eliminate run backs.

In addition to the modifications that were specifically for uprate, we've done a lot of piping replacements that are referred to. Inside the drywell, we've replaced a large amount of the piping in there to eliminate IGSCC concerns. We replaced the entire recert system in Unit 1 all the way from the safe ends through the pumps and back to the safe ends on the emit nozzles. We replaced all that with 316 NG piping. Similarly, we replaced all the RHR piping inside the -- well, all the RHR injection piping inside the drywell, the core spray piping and the RWCU piping with IGSCC resistant material.

Outside the drywell, we've also performed modifications to accommodate the higher steam flows out in the extraction steam lines, we've replaced the number two, three and four extraction lines with the chromoly material. The -- what we did on Unit 1 was we took a proactive approach and went ahead and replaced it. Even though we probably could have gotten a few more years of operation out of it, we went ahead, as part of the recovery, replaced it with the IGSCC material. Not only did we do the large lines, we also took the lessons learned from Units 2 and 3 where on their FAC program, if they were experience a particular problem at a certain location, we went and applied that lessons learned generically in Unit 1 to go replace all typical -- all similar type locations so that we should have a plant that's much more robust and able to handle the higher steam flows associated with extended power uprate.

If there are no other questions, I will turn it back to the NRC staff.

MEMBER BONACA: Thank you.

MS. BROWN: For this discussion, it is the intent to address the guidance and assumptions used by the staff for the Unit 1 105 percent review and briefly discuss the resolution of various special topics such as the included EPU license renewal review or Unit 1 differences regarding power uprate testing. Additionally, the staff added some special items of interest applicable to both the 105 and the 120 percent reviews.

As we discussed previously, the licensee's 105 percent amendment request was made in September of last year. The analysis was conservatively performed at 120 percent using the approach, guidance and assumptions from the EPU Licensing Topical Reports that were discussed previously. This interim submittal included the request outlined here.

The Unit 1 interim uprate was reviewed using the process and acceptance criteria outlined in RS-001. The review confirmed that the information provided was developed using approved codes and methodologies and consistent with the results outlined in approved EPU Topical Reports. This allowed the staff to then focus on the more significant changes to determine whether the information provided met the 105 percent acceptance criteria. Where applicable, the precedent from eight years of operation at 105 percent on Units 2 and 3 was credited. The results of the staff review was then compiled onto the SE template provided in RS-001.

On Unit 1, the 105 percent review was actually conducted after a significant portion of the technical review for the 120 percent was completed This allowed the staff to either re-review the information for 105 percent or confirm that the 120 analysis remained bounding. This approach also required confirmation and technical review for the related license amendments relied to support the 120 percent remained acceptable for the 105. The listed amendments were among those reviewed by the staff. Not all the amendments listed here are necessary for the 105 percent approval, but they are provided for completeness as they were reviewed as part of the bounding at 120 percent staff review.

Similarly, some aspects of the Unit 1 105 percent review also depended on the previous Units 2 and 3 105 percent approval. Additionally, much of the

Units 2 and 3 120 percent review was conducted using the exact same processes, methodologies and acceptance criteria from the review standard and generic topical reports reviewed for the Unit 1 uprate with the same acceptable outcomes. For completeness, the other 120 percent related amendments needed to support the Units 2 and 3 120 percent review are included here.

For the Unit 1 105 percent review, almost all the analyses provided by the licensee were conducted at 120 percent. The staff's review found that either the 5 percent uprate had no affect or no significant increase in the affects on a system. Where a system structure or component was affected, it was confirmed that the effects remained within the previous acceptance criteria. This holds true with plant programs like the EQ, FAC or stress corrosion cracking programs.

One exception was identified in the area of thermal limits where one limit was specifically requested by the staff to be re-evaluated at 105 percent, and this is the discussion you previously had with TVA regarding the 105 percent core review.

MEMBER BONACA: Eva, on the flux or early corrosion issue, if I understand it, the only reason why it seems to be acceptable is that they are going to rely on Unit 2 and 3 for the first cycle, and then they're going to, if I understand it, they're going to use plant-specific information for measurements to support the FAC program? Is that what we heard at the subcommittee?

MS. BROWN: Sounds correct. I can't speak for TVA. I'd have to --

UNIDENTIFIED SPEAKER: Five percent more.

MEMBER BONACA: Well, I mean -- okay. You're saying Unit 2 and 3 programs are applicable to Unit 1?

MS. BROWN: Yes, sir.

MEMBER BONACA: And we questioned that at the subcommittee, in fact. And the answer we got was that at the end of the first cycle, there would be measurements made and those would provide the first baseline information regarding flux corrosion program for Unit 1.

MR. CROUCH: This is Bill Crouch. The -- in Unit 1, we're going out and performing measurements for all the FACs-acceptable locations as a baseline, and then the -- well, we'll verify that we have adequate min. wall to handle a full cycle of operation. But that conclusion, yes, is based upon our experience from Units 2 and 3 so we know the erosion rates from Units 2 and 3. And then at the end of that cycle, we'll perform confirmatory measurements and then project on out to the future.

MEMBER BONACA: Yes. That's why I wanted to verify, in fact, that we discussed this issue, and we considered this approach acceptable because after first cycle, you're going to measure it again and verify that it becomes applicable so --

MR. CROUCH: That's correct.

MEMBER BONACA: -- plant specific. Okay.

MR. CROUCH: Yes.

CHAIRMAN SHACK: How much of that steam piping is chromoly? All of it or?

MR. CROUCH: The main steam piping itself is a carbon steel piping. The extraction steam piping, you've got five extraction steam points, one through five, and we will have replaced number two, three and four with chromoly. In Units 2 and 3, we have seen no impact on the Unit 1 extraction because it's such high-quality steam. And we've seen no impact on the number five extraction, because it's sub-atmospheric. The two, three and four is where we've seen any of the problems at all, and that has all been replaced in Unit 1.

MS. BROWN: Thank you. Moving on. The

validation of the assumptions discussed previously combined with the precedent from the operating units at the same power and the review of any special items resulted in the staff's conclusion that for the 105 percent power uprate, the analyses used acceptable codes and assumptions. An acceptable margin remained at 105 percent, and all regulatory acceptance criteria was met. This provides reasonable assurance that the Unit can be safely operated a 105 percent of the original licensed power.

MEMBER KRESS: Excuse me. Just out of curiosity, what do you mean by an acceptable margin?

MS. BROWN: An acceptable margin to the limit.

MEMBER KRESS: Limit of what?

MS. BROWN: Whatever the performance measure would be.

MEMBER KRESS: Whatever the performance measure for a design basis accident is?

MS. BROWN: Yes, sir.

MEMBER KRESS: So it's -- just as long as it's below that, it's acceptable? I mean is there some range or confidence level or?

MEMBER CORRADINI: When do you get nervous?

MEMBER KRESS: Yes.

MS. BROWN: When do we get nervous?

MEMBER CORRADINI: Yes. And Tom's question basically is there's margin --

MS. BROWN: Yes, sir.

MEMBER CORRADINI: -- and then there's an increase in power. There's less margin.

MEMBER KRESS: Maybe.

MEMBER CORRADINI: So at what point do you start getting --

MEMBER KRESS: Yes. What is an acceptable margin is what I'm asking --

MEMBER APOSTOLAKIS: Because principle -- only when you cross the threshold, right?

MS. BROWN: Yes, sir.

MEMBER APOSTOLAKIS: That's a deterministic word.

UNIDENTIFIED SPEAKER: It's a bright line.

MEMBER APOSTOLAKIS: You are at epsilon below.

MEMBER KRESS: I'm glad to hear you say that.

MEMBER APOSTOLAKIS: What?

MEMBER KRESS: I'm glad to hear you say that.

MEMBER APOSTOLAKIS: I think that's the truth, isn't it?

MEMBER KRESS: That's --

MS. BROWN: Yes, sir.

MEMBER KRESS: Okay. Wonderful.

MEMBER MAYNARD: The margin's actually built into the limit?

MEMBER APOSTOLAKIS: That's right.

MS. BROWN: Yes, sir.

MEMBER APOSTOLAKIS: That's exactly.

MEMBER KRESS: So as long as you're below that limit, you're good?

MEMBER APOSTOLAKIS: Right. Exactly.

MS. BROWN: Yes, sir.

MEMBER KRESS: Okay. That's all I need.

MEMBER APOSTOLAKIS: So a more accurate --

MEMBER KRESS: That's all I wanted to know.

MEMBER APOSTOLAKIS: A more accurate bullet would be --

MEMBER SIEBER: But that's not a bright line.

MEMBER APOSTOLAKIS: -- the limits --

MEMBER BONACA: You're right, George. I mean the special would be margin is maintained --

MEMBER APOSTOLAKIS: Or --

MEMBER BONACA: -- not accept --

MEMBER APOSTOLAKIS: -- or we have respected the limits, something to that effect. And then it's as Eva says, if you do that, then it's understood that you have sufficient margins.

MEMBER BONACA: That's right.

MEMBER APOSTOLAKIS: When they set the limits, that's what they have in mind.

MEMBER BONACA: Yes, I agree.

CHAIRMAN SHACK: Well, that's why 2 and 3 always seem to me to be the same answer.

MEMBER APOSTOLAKIS: Yes. Exactly. Yes.

MS. BROWN: Thank you.

MEMBER APOSTOLAKIS: So then we have reasonable assurance. In fact, all three of them are the same thing.

MS. BROWN: Well, he closed out my slide for me there.

(Whereupon, off the record comments.)

MEMBER APOSTOLAKIS: Interesting points -- risk. Well.

MS. BROWN: The previous discussion focused on those items --

MEMBER POWERS: Let me explore something

a little further with you. Can you describe to us exactly how they use the alternate source term?

MS. BROWN: Michelle, would you like to?

MS. HART: This is Michelle Hart from the NRR staff. For all three units, they had provided a previous alternative source term encompassing 120 percent power. That was approved previous to them even sending in any of these amendments so that for the 105 percent power uprate, that analysis had already included that power range.

MEMBER POWERS: I take it from your answer that you said, okay, we've approved the alternate source term for this and so we're not going to look at the -- we don't need to look at it for the 105, all it does is change the inventory?

MS. HART: That is correct. We did verify that the steaming rates and things like that were also what was done in the alternative source term amendment.

MEMBER POWERS: I bring the issue up for two-fold reasons. One, you know that the alternate source term really isn't directly applicable to very high burnup fuel? And second of all, you know how sensitive they are to the particulars of the alternate source term?

MS. HART: That I don't have right now. I don't know that they are particularly sensitive. I don't even have the doses with me right now. I can say that the fuel types were looked at in the alternative source term amendment. They talk about using the ATRIUM-10 fuel. That was analyzed for the alternative source term amendment.

MEMBER MAYNARD: Do I understand that the alternate source term submittal that you'd looked at, that was done at 120 percent? Okay. So the 105 percent is encompassed by that? Okay.

MS. HART: That is correct.

MEMBER MAYNARD: Okay.

MS. BROWN: Thank you. Our previous discussion focused on those items whose assumptions, analyses, methodologies and results were routine due to the staff's confirmation that the analyses contained in the approved EPU Topical Reports remained bounding. However, as with most submittals, there were some unique or interesting features that arose during this review. Our main discussion will focus on these aspects.

On several occasions, I've mentioned that some of the analyses were performed at both the 105 and 120 percent. For the EPU and the 105 percent, the staff's review concluded that the fuel design and operation review conducted at 120 percent should conservatively bound the 105 percent operation. However, the staff was concerned that prolonged changes in operating strategy could affect core power distribution which could, in turn, require an increase in the SLMCPR. Therefore, the staff requested that TVA and GE re-perform the SLMCPR calc using a limiting control rod pattern and a limiting stay point. The results indicated that the SLMCPR limit calculated remained acceptable.

MEMBER APOSTOLAKIS: So on this slide, when you say analyses currently based on 120 percent, the first bullet applies to this? Therefore, these analyses envelop operation at 105? Is that what you mean?

MS. BROWN: Our only intent with this slide was to compare and contrast some of the analyses that we decided to have re-done at 105 percent to show that they were performed at both powers.

MEMBER APOSTOLAKIS: So the third bullet then says you accept the 120 percent analyses as bounding the 105?

MS. BROWN: Yes, sir, by confirmation.

MEMBER BONACA: Yes, but --

MEMBER APOSTOLAKIS: What?

MS. BROWN: Yes.

MEMBER BONACA: No. I have a -- but why did you have to perform LOCA analyses again at 105 percent power?

MS. BROWN: In the beginning, we weren't sure what the outcome was going to be for the exact concern that you had mentioned earlier. So the staff went back and looked, and the results of that look supported our initial assumption that the 120 percent remained bounding.

MEMBER BONACA: Okay. Thank you. If I understand now, this -- all this information on specifically 105 percent power was part of the submittal which had just come from TVA?

MS. BROWN: Yes, sir.

MEMBER BONACA: Okay.

MS. BROWN: That -- you're talking about the September 22nd, 2006 interim request. And the fuel information came sometime a little later.

MEMBER APOSTOLAKIS: So all these are TVA analyses?

MS. BROWN: Yes. I believe that's true.

MR. BANERJEE: Did you do any confirmatory analysis?

MS. BROWN: George?

MR. THOMAS: Yes, this is George Thomas from Reactor Systems. We did independent LOCA calculations using RAMONA.

MEMBER APOSTOLAKIS: You said they. Who's they?

MR. THOMAS: Sorry. RELAP. Sorry.

MEMBER APOSTOLAKIS: Did you say they?

MR. THOMAS: Pardon?

MEMBER APOSTOLAKIS: Would you repeat your answer, please?

MR. THOMAS: No. You did independent calculations you're saying --

MEMBER APOSTOLAKIS: We --

MR. THOMAS: -- RELAP.

MEMBER APOSTOLAKIS: Okay. Thank you.

MR. BANERJEE: For which conditions?

MR. RAZZAQUE: I'm Mohammed Razzaque from Reactor Systems. As we presented in the subcommittee, results for both 105 and 120 calculated by, of course, Framatome, and what we did in-house with RELAP-5 is 120 percent LOCA. And we have discussed doing -- this represented and detailed the result why we're satisfied, why we did not have to do 105 again independently. Because we understood the -- how 105

-- 120 was sufficient calculation.

MEMBER KRESS: Does that list the dominant risk sequence for Browns Ferry.

MR. RAZZAQUE: I don't understand. What's --

MEMBER KRESS: ATWS -- maybe this is a

MR. RAZZAQUE: Oh, ATWS.

MEMBER KRESS: This is a question Marty may -- is that the dominant sequence --

MR. STUTZKE: No, it's station blackout.

MEMBER KRESS: It's station blackout?

MR. STUTZKE: Yes. It's typical BWR.

MEMBER KRESS: Why didn't we do a station blackout confirmatory calculation then instead of a LOCA.

MR. STUTZKE: Not going to touch that.

MEMBER APOSTOLAKIS: What kind of analyses would you expect?

MR. STUTZKE: With respect to these types of calculations, it's licensing calculations. Yes, these are licensing risk calculations.

MEMBER APOSTOLAKIS: I see.

MEMBER POWERS: The station blackout is a licensing accident?

MEMBER KRESS: Yes. That's one of the

design basis accidents.

MR. RUBIN: This is Mark Rubin from the staff. Some mitigation capability for SBO is, of course, a regulatory requirement but is not per se a licensing basis accident analyzed against acceptance criteria. It's dealt with based on risk insights about 20 years ago with some plant modifications to increase the capability of the plant test field.

MEMBER BONACA: Yes. And I understand that but it's a confusing thing for reviewers. For example, the Appendix R scenario that we'll discuss later on, it's limiting from a perspective of the length of credit for NPSH as well as the amount of credit. Yet it's not even recognized in the SCR up front as a licensing amendment. The SCR only states that two psi or three psi are required for the LOCA event. It doesn't mention the other events and so one is left with the question of are they part of the licensing basis or are they not. And so I guess they are but they're not.

MR. LOBEL: This is Richard Lobel from the staff. There's a difference between a licensing basis and a design basis. The ATWS Appendix are, in station blackout that I talked about, are part of the licensing basis, but they're not design basis accidents in the sense that the plant is designed to mitigate those events. But they are part of the licensing basis and analyses are required, and there are acceptance criteria that have to be met. And in some cases, there is equipment that's taking credit for the function. In some cases, the equipment is there to mitigate but no credit is taken in the analysis. So the difference is between licensing basis and design basis.

MEMBER BONACA: All right. I appreciate it. Thank you.

MEMBER KRESS: I'm curious. Does design basis have a definition or a regulatory position --

MR. LOBEL: Design basis --

MEMBER KRESS: -- as opposed to a licensing basis?

MR. LOBEL: Design basis is defined in 50.2, which is definitions in the Code of Federal Regulations, and licensing basis is defined in Part 54 under License Renewal.

MEMBER MAYNARD: These licensing bases, when we're talking like about station blackout, they really -- they go beyond the design bases. You lose more equipment than you're required to assume in a design basis accident, but they're ones that the regulators have determined to be still of sufficient significance that they have mitigating consequences or mitigation and stuff taken. So they're ones that go beyond design basis accident. You have to lose more equipment than what you're required to assume during design basis to get into these conditions?

MR. LOBEL: Right. There's no single failure assumption as there is a for the design basis accidents.

MR. SIEBER: And your mitigating equipment need not meet class 1A standards?

MR. LOBEL: That's right, too, yes.

MEMBER BONACA: And this is an important issue that I think we'll take again when we talk about NPSH, because that defines some of the basic requirements for Appendix R which are different than design basis requirements. So I understand? So we'll look at it. Okay. Thank you.

MS. BROWN: Thank you. Moving on to license renewal, with most facilities, the licensee has gained approval of the power uprate first and then requested a renewal at the newly approved extended uprate conditions. As Bill mentioned, one of the unique features of this review is the fact that the Browns Ferry facilities had their operating licenses extended for an additional 20 years before the uprate approval. This was not TVA's original intent.

Back in 2002, the licensee had originally indicated that EPUs would be submitted first and then the license renewal. However, TVA ended up submitting the license renewal in 2003, and the staff issued our approval in 2006. Just like the Unit 1 105 review, the license renewal analysis was conservatively performed at 120 percent.

However, the license was renewed at the existing operating license power level, which was 100 percent. This has resulted in the staff having to add a license renewal review for the uprated power conditions. So we performed a review from looking at 100 all the way through 120 percent as part of the uprate review. And this is something we've not done in the past.

MEMBER CORRADINI: Can I --

MEMBER APOSTOLAKIS: Go ahead.

MEMBER CORRADINI: We both were confused. Can I just say it back to you to make sure I get it right?

MS. BROWN: Yes, sir.

MEMBER CORRADINI: When you said all the way through, you mean you were looking at it at 105 and then you're going to have to re-look at it at 120? That's what I interpret that to mean?

MS. BROWN: No, sir.

MEMBER APOSTOLAKIS: No, that's not what she meant.

MS. BROWN: Just like we started up at the beginning, we had essentially completed a majority of our review at the 120 percent, including those aspects for license renewal, aging management and the time-limited aging analysis.

MEMBER CORRADINI: Okay.

MS. BROWN: So we just had to confirm that there was nothing created through the 105 percent that would change our conclusions that we obtained at 120.

MEMBER CORRADINI: Thank you

MEMBER APOSTOLAKIS: But that doesn't mean that there is document that say you have approved the 120 -- I mean the license? Okay.

MS. BROWN: In the --

MEMBER APOSTOLAKIS: You have done the analysis? That's all you are saying?

MS. BROWN: Yes. But we do have a discussion that addresses -- in some specific topics, there is a discussion on extending operating conditions. That's, you know, our code for licensing renewal conditions.

MEMBER CORRADINI: But the way I interpret -- if I just might -- the way I interpret everything you've let up to except that statement, I heard it as if calculations were done at 120, you looked at them, you reviewed them, you even did confirmatory calculations, but all conclusions derived today are at 105 and only 105, although the 120 calculations may be bounding. But that's how I'm interpreting all the presentation. I'm looking at the Chairman because I want to make sure we're on the same page.

MEMBER BONACA: We are looking at 105 percent.

MEMBER CORRADINI: Right.

MEMBER BONACA: That doesn't --

MEMBER CORRADINI: And all conclusions derived even from 120 percent calculation are only focused at 105? Yes. Because --

MEMBER BONACA: This is the licensing action --

MS. BROWN: For this discussion --

MEMBER BONACA: -- we're considering now.

MEMBER CORRADINI: Yes. That's fine.

MR. SIEBER: That doesn't mean that we're going to avoid or redo all of that review --

MEMBER CORRADINI: No. I didn't expect --

MR. SIEBER: If it's approved at 120, it's approved at 120.

MEMBER BONACA: Yes. But I think it's an important point that we're discussing here because, I mean, we're not going to say at the end of this meeting that we approve at 105, and by-the-way, we have reviewed everything for 120. We're not going to say anything like that. I mean clearly --

MEMBER APOSTOLAKIS: That would be another review, right?

MEMBER BONACA: Yes. And when it comes to that, we are reasonable people. We recognize that what we already have looked at the 120 and we felt comfortable with, we're going to accept it.

MEMBER APOSTOLAKIS: Right.

MEMBER BONACA: But we can't put a fence now and say we cannot ask questions at 120.

MS. BROWN: Not at all.

MEMBER BONACA: And then -- so that's a different licensing action. That will come in the summer.

MR. RUBIN: This is Mark Rubin again. I believe from the subcommittee meeting, the subcommittee staff members indicated two areas they wanted to follow-up prior to the 120 percent. One was the core analysis and I forget the second, but not a complete re-evaluation.

MS. BROWN: Steam dryers.

MR. RUBIN: Thank you. Steam dryers. I should have remembered.

MEMBER BONACA: But again, I want to point out that --

MS. BROWN: But most --

MEMBER BONACA: -- the 120 percent to be in front of us, we may come on an issue that we have not recognized yet and have questions for it, and I don't think that we are limited in asking those questions.

MS. BROWN: Yes, sir.

MEMBER MAYNARD: The way I understand our job today, we may or may -- we may agree that the analysis is bounding for 105, but we're not saying that it's bounding for 120 percent?

MS. BROWN: Yes, sir.

MEMBER MAYNARD: We can revisit anything.

MS. BROWN: And the staff echoes that. The staff's review at 100 percent is not complete and none of my statements should be construed to infer that the staff is in effect approving the 120 percent power uprate. We are not there. Thank you.

The staff, using some information provided during the license renewal review, went back through the submittal focusing on the time-limiting aging analysis and aging management programs that might be affected by the uprate. For the aging management review, the staff required evaluation of EPU modifications to determine any impact on the license renewal. Preliminary reviews of EPU mods of all three units found that the progress of these mods range from design status to complete. More importantly, it was found that no additional components, materials or environments had been introduced.

Therefore, the staff found that no TLAAs needed to be re-performed and the aging management review performed remained acceptable at uprated conditions. Licensee will be performing confirmatory reviews of the as-built configuration regarding the addition of new components, materials or environments to ensure that the conclusions regarding the renewal analyses remain valid.

Moving on to testing. The power uprate test program was reviewed again the criteria in the staff's review plan for its Section 14-2.1 as well as Appendix L of the EPU Licensing Topical Report to ensure that it included adequate system, component post-mod, component maintenance, tech spec surveillance and restart testing. It should be noted that the proposed Unit 1 restart and power ascension tests up to the old 100 percent are similar to tests conducted for the Unit 3 restart which occurred in the 90's.

MEMBER BONACA: But this test program is the restart test program. It's not necessarily the uprate?

MS. BROWN: Exactly.

MEMBER BONACA: So for example, some of this testing will not be done at the 105 or 120. It will be done at what power?

MS. BROWN: It depends. There was -- it's a very integral test program that we provided yesterday during the subcommittee.

MEMBER BONACA: Yes.

MS. BROWN: And give me -- roll to the next slide. For the testing from 100 to 120 percent which is more of our focus. In support of the uprate, the original test plan up to 120 was intended to be performed in 2 to 5 percent increments. At each increment, the licensee intended to assess the core power distribution and perform testing, not unlike the pressure regulator condensate feed system, do single pump trip testing and verify vessel water level, rad level --

MEMBER BONACA: Exactly. And I --

MS. BROWN: -- monitor --

MEMBER BONACA: -- I see those --

MS. BROWN: Right.

MEMBER BONACA: -- as power uprate. I mean --

MS. BROWN: Yes, sir.

MEMBER BONACA: -- you have these new pumps, etcetera. You want to test the logic, too. You want to make sure you have individual pump trips --

MS. BROWN: Yes, sir.

MEMBER BONACA: -- to verify performance and also that you have the transient tests. I mean -- okay, so those are -- all right.

MS. BROWN: Yes. So additionally, the licensee has proposed steam dryer monitoring similar to Vermont Yankee's test program with the exact increments and data submission requirements to be determined at the completion of the staff's dryer review.

MEMBER BONACA: Now that's an uprate test.

MS. BROWN: With the Unit 1 interim request, the licensee will still perform the testing listed previously, but naturally it will be limited to 105 percent as far as the increments. The balance of the plant will be monitored as listed here.

Due to the extensive restart and uprate modifications on Unit 1 as well as the extended shutdown period and lack of relevant operating experience, the NRC staff found that consistent with the guidance in the Standard Review Plan and Appendix L of the EPU Topical Report, additional tests were needed for Unit 1. Therefore, the staff imposed two license conditions requiring the single pump trip testing for the condensate and feed pumps and the performance of two large transient tests.

The integrated testing achieved by performing the MSIV closure and load reject test on Unit 1 will serve to effectively confirm plant response and analyses. Additionally, the transient testing of the condensate feed system will confirm the acceptability and consistency of pump operation with analytical results as you just mentioned.

From this proposed test program, as supplemented by the imposed license conditions, the staff found that the power ascension testing meets the acceptance criteria outlined in our Standard Review Plan Section 14-2.1, the suggestions of Reg Guide 168 and the guidance in Appendix L of ELTR1, and therefore provides reasonable assurance that effective system structures and components will perform satisfactorily in service at 105 percent.

Lastly, the status fo the steam dryer review is changing frequently. However, although there are issues at the EPU condition of 120 percent, the licensee has seen no cracking attributable to the increase in power on the two operating units who operated to 105 percent in 1998. As there are no concerns with vibration at 105 percent, Units 2 and 3 have successfully operated at 105 percent for 8 years and the Unit 1 steam dryer has been modified so it's more robust than the Units 2 and 3 dryers. The staff has determined that Unit 1 operation at 105 percent is acceptable.

However, TVA will be monitoring the main steam line strain gauges, moisture carry over and vibration for dryers and conduct walkdowns during the 105 percent power ascension to support the ongoing Browns Ferry steam dryer 120 percent review.

MEMBER ABDEL-KHALIK: It's my understanding that neither the steam line instrumentation nor the model used to relate the steam line measurements to what's happening in the steam dryer would actually predict performance at low frequencies below 30 hertz. The question is what plans, if any, does the applicant have to monitor vibrations at low frequencies?

MS. BROWN: Bill, do you guys want to -- Rick?

MR. CUTSINGER: This is Rick Cutsinger, TVA Civil Manager. At the steam line measurements on the infrequencies, you can see the amplitudes as we come up in power. We have also worked with our contracting, Continuing Dynamics, to develop a low frequency fluctuating pressure load distribution to put on to the dryer to make sure that we have good capacity.

MEMBER ABDEL-KHALIK: I guess I -- from the subcommittee discussions, I guess the point was made that below 30 hertz, there is no indication that whatever you're measuring at the steam lines has any sort of bearing or relation to what's happening in the steam dryers.

MR. CUTSINGER: I think in the subcommittee, my recollection was we talked about how we could see the low frequency fluctuations. Now in some units, like Quad Cities, there were no low frequency fluctuations in that plant, and also inside the steam dryer they saw no low frequency. However, at Browns Ferry, we do see low frequency amplitude in our steam line measurements and we have taken those into account when we developed a load definition. And we'll be discussing that with the staff here when we make our submittal in April.

MEMBER ABDEL-KHALIK: Thank you.

MS. BROWN: And just, in conclusion, as Tim and TVA mentioned earlier, that staff will be getting the additional steam dryer information around April 2nd, which will take a look at the Unit 1 and Unit 2 steam dryer analyses. So we'll be going through this in a lot more detail when we return to the subcommittee in the summer or fall, whatever the date ends up being.

MEMBER KRESS: What can you see with the walkdown? I see you got -- that's part of the assessment?

MR. VALENTE: This is Joe Valente, TVA. What we expect to see in a walkdown is balance of plant piping. We have intentions to place out some accelerometers, LVDTs, plus in addition, have our AUOs and System Engineers monitor portions of the plant.

That's during normal ops up to 105 and then beyond in to the power ascension.

MEMBER MAYNARD: A couple of things. You know, experienced operators can certainly tell a difference when they're walking around if there is a different vibration level, or also hangers and other attachments, you can --

MR. SIEBER: Fasteners --

MEMBER MAYNARD: -- Fasteners, you can -- there are some things you can see, but it is limited.

MEMBER KRESS: But you're comparing that to what you normally see.

MR. SIEBER: Yes or what you should see.

MEMBER KRESS: Or what you should see.

MR. SIEBER: What you should see.

MEMBER KRESS: Okay. That's different.

MEMBER CORRADINI: It's like a car. If it's humming differently, you start investigating.

MEMBER KRESS: Okay. I'm not against walkdown, it's just --

MS. BROWN: So at this point, we're going to turn it over to Mr. Marty Stutzke who's going to look at -- address EPU risk.

MR. STUTZKE: Good morning. I'm Marty Stutzke, a Senior Reliability and Risk Analyst in the

Office of Nuclear Reactor Regulation Division of Risk Assessment.

MEMBER KRESS: You might note that George is here today, and I don't have to be George. I was you at the subcommittee.

MEMBER APOSTOLAKIS: And there you shaved?

MEMBER BONACA: No. We also have a presentation by the licensee, right, on the NPSH issues?

MS. BROWN: Yes, sir. It's going to follow the --

MEMBER BONACA: Going to follow that. Okay.

MR. STUTZKE: I'm personally delighted to be the first staff member to provide you with the technical presentation. Usually, I get stuck with the end of the day. At the same time, I find it remarkable that we're here to discuss --

CHAIRMAN SHACK: You're the last one before the coffee break, though.

(Laughter.)

MR. STUTZKE: Right.

UNIDENTIFIED SPEAKER: You're very brave.

UNIDENTIFIED SPEAKER: And moving right along.

MR. STUTZKE: I also find it interesting that the PRA guy's up here talking to you first and yet it's a non risk-informed application.

MEMBER KRESS: All applications to the ACRS are risk-informed.

MR. STUTZKE: Well, I would certainly agree all presentations to the ACRS are risky.

(Laughter.)

MR. STUTZKE: Okay. I would point out that with respect to power uprates, we don't routinely look at the risk aspects of power uprates that are below extended power uprate that's about 7 percent. With respect to the Browns Ferry 5 percent uprate that we're here to discuss today, we realize they needed credit for containment accident pressure in certain situations to provide adequate net positive suction head to the emergency core cooling pumps, and that has a risk element to it. In fact, the way the analysis is conducted is it's difficult for us to look at the difference in risk between 105 percent and 120 percent with respect to the containment accident pressure and I'll explain why. It has to do with the crudeness of the model and assumptions.

MEMBER POWERS: Let me understand correctly. You're only looking at Level 1 PRA?

MR. STUTZKE: We're looking at Level 1 PRA and the large early release frequency calculation.

MEMBER POWERS: But nowhere in these analyses do you take into account inventory?

MR. STUTZKE: Correct.

MEMBER POWERS: Then why is this useful? If the one feature of a power uprate is increasing the inventory and you neglect it in a risk analysis, why is it useful?

MR. STUTZKE: Well, I would argue that you know the inventory's roughly proportional to the amount of power so that you know the overall risk goes up proportional to the increase in power. The reason why it's useful is that the power uprate does, in fact, change the aspects of the Level 1 PRA success criteria, operating timing. These are things that we can control and can look at them. But I believe it does have benefit.

MEMBER APOSTOLAKIS: All right. Keep going.

MR. STUTZKE: Okay. Slide 2, the affected PRA elements, specifically what was done to examine the risk at 120 percent EPU was there were changes in success criteria, enhanced CRD flow, control rod drive flow, main steam relief operations, varying anticipated transients without scram scenarios and, of course, the containment accident pressure credit. As a result of the changes in success criteria, there were corresponding changes in the event trees and the fault tree logic itself. In addition, some of the post initiator operator action failure probabilities were changed as well.

Okay. Moving on to the impact on success criteria. The licensee did a rather large set of analyses of the MAAP code to re-evaluate the success criteria, and they discovered there was a change in the enhanced CRD success criteria. Specifically for Units 2 and 3, they found that at the extended power uprate conditions, enhanced CRD flow was not adequate for the first six hours following reactor trip. What that implies is that if you're in a high pressure scenario where you've lost main feed water or reactor feed water, IPSI and RPSI, the operator would then have to depressurize early on in order to get down to use the low head pump, the operators.

Beyond six hours, if that depressurization failed, they could still run enhanced control run drive. For Unit 1, at the extended power uprate conditions, the enhanced CRD system is not even modeled.

MEMBER CORRADINI: After six -- just one clarification. You mean six hours after shutdown?

MR. STUTZKE: Six hours after shutdown. Okay. And of course, for the 105 percent, plant conditions enhanced CRD always -- is always available.

It turned out to have a notable impact on the core damage frequency in the large early release frequency, size of the impact we have never seen before power uprates.

In addition, there were changes to the MSRV success criteria, a change of 9 out of 13 to 11 out of 13. It's a small impact because the failure probability is driven by the common cause and you can't really see the difference --

MEMBER CORRADINI: Can I -- just -- you said this in the subcommittee. I just want to -- just if you could just repeat it in detail. So the reason is that without the -- with the unavailability of this enhanced CRD, then the chance of not being able to depressurize becomes more significant and that's the reason --

MR. STUTZKE: That's correct.

MEMBER CORRADINI: -- that your CDF goes up? And the LERF only goes up because the CDF goes up? It doesn't go up because of anything -- to get back to Dana's point, it goes up only because of it's coupling to the CDF.

MR. STUTZKE: That's correct.

MEMBER CORRADINI: Okay.

MR. STUTZKE: Okay. Containment Accident Pressure Model -- basic notion is that under certain plant configurations, conditions, the loss of containment integrity implies you lose the over pressure, the core spray and RHR pumps cavitate which is a loss of their functionality in the PRA model. When we look at the loss of containment integrity, the only failure modes that are considered are pre-existing leaks and the failure to achieve the containment isolation. So we're not looking at any time-dependent failure modes such as loss of the containment isolation once it's been achieved, perhaps spurious valve transferring open, this soft of thing. We're certainly not looking at leaks that were developed in the containment post trip, for example, degradations of seals or things like that.

MEMBER APOSTOLAKIS: When you say we're not looking, what is the basis for that? I mean --

MR. STUTZKE: Well, the argument is that they're low probability.

MEMBER APOSTOLAKIS: So we're really

screening them out? It's not we're not looking at -- okay.

MR. STUTZKE: Okay. With respect to the success criteria for large LOCA, I'll remind the committee of the discussions we had on Vermont Yankee. In that PRA, we assumed that if you lose containment integrity, the core spray and RHR pumps would always cavitate regardless of the plant conditions and the equipment configuration That was going on. And the committee challenged us and future licensees to give this a harder look. This was done for large LOCAs at the Browns Ferry, and you end up with an interesting set of success criteria here. You find if you're running several RHR pumps, three or four RHR pumps in suppression pool cooling mode, you don't need containment integrity at all. In other words, the pumps won't cavitate.

If you're running two RHR pumps for suppression pool cooling, you may need containment integrity under certain plant conditions. Of course, it depends on the power level, the initial suppression pool, inventory, the temperature of the river water and the temperature inside the pool.

Thus, if you're only running one pump for suppression pool cooling, you always need the containment integrity regardless of the plant conditions.

MEMBER CORRADINI: And what you're quoting here is Vermont Yankee?

MR. STUTZKE: No. These are the conditions found expressly for Browns Ferry.

MEMBER CORRADINI: At --

MR. STUTZKE: At Vermont Yankee, we assumed you always needed the containment integrity regardless of what was going on in the plant.

MEMBER CORRADINI: Okay. And maybe it's later to explore this, but somewhere I want to ask because I have the Vermont Yankee letter, and I want to get clear what you just said versus what's expressed in the letter in terms of this. But for Browns Ferry, this is all at 120 percent, correct?

MR. STUTZKE: That's correct.

MEMBER CORRADINI: And then if this was a -- I'm going to go back, because I -- this is a licensing calculation, not a design basis calculation. So in a licensing calculation, any one of these possibilities is allowed to be considered? You see where my question is going?

MR. STUTZKE: Well, be careful. These are not even licensing calculations. These are PRA success criteria calculations.

MEMBER BONACA: Yes. For the licensing basis --

MEMBER CORRADINI: I'm sorry. Excuse me. Can you repeat that, Mario. I'm sorry.

MEMBER BONACA: For the licensing basis, it's two RHR.

MEMBER CORRADINI: Okay. Thank you.

MEMBER BONACA: Because it's one train -- one train of two RHR is lost, then you have this four RHR.

MR. STUTZKE: Right. There are no deliberately introduced conservatisms in these types of calculations. It's realistic.

MEMBER ARMIJO: How does this chart change for 105 percent power?

MR. STUTZKE: You know what? To be honest, I don't know, because we did not calculations -- the licensee did no calculations for 105 percent.

MEMBER KRESS: It's probably about the same.

MR. STUTZKE: My judgment says --

MEMBER BONACA: No, no. Quite less.

MR. STUTZKE: -- it should be roughly the same.

MEMBER BONACA: But --

MEMBER CORRADINI: But the function of the power in this --

MEMBER BONACA: But at 105 percent, you're total temperature is much lower. It's -- original would be close to 100 percent.

MR. STUTZKE: Correct.

MR. BANERJEE: Did the staff check any of these calculations?

MR. STUTZKE: No, we did not.

MR. BANERJEE: Who did the calculations?

MR. STUTZKE: I will refer to TVA.

MEMBER APOSTOLAKIS: Aaron Engineering?

MR. BANERJEE: Who?

MEMBER APOSTOLAKIS: Aaron --

MR. STUTZKE: Aaron Engineering.

MEMBER APOSTOLAKIS: Consulting firm?

MR. ANDERSON: Yes. My name is Jason Anderson with Aaron Engineering. Yes. I was the guy who did the risk assessment for the containment accident pressure. Same -- I did the same thing for Vermont Yankee. As Marty said, for Vermont Yankee, they wanted to do the conservative route which was just for the risk assessment, just throw the need for containment integrity across the entire PRA, which the

ACRS, at the time, didn't like the conservative approach. So this time around, we were a little bit more specific trying to integrate specific accident scenarios.

MR. BANERJEE: I meant -- maybe I didn't ask my question well, but, for example, the temperatures, pressures and --

MR. ANDERSON: Yes. And those --

MR. BANERJEE: -- pressure losses, you did all those calculations?

MR. ANDERSON: There were deterministic calculations done for the thermohydraulic issues on when NPSH was needed. Those were performed by GE. The statistical review of plant experience as far as the historical river temperatures and the exceedance frequencies, of all those items in the second bullet, we did those. We gathered plant data and reviewed them statistically to come up with exceedance frequencies and then addressed the tendencies between things such as river temperature and torus temperature. Obviously, they're not independent.

MR. BANERJEE: So you took the results of the GE calculations and put it in your own --

MR. ANDERSON: Yes. We looked at the GE calculations, determined which were the key contributors and then had GE perform a host of different calculations, varying input parameters. And then we used that to determine which accident scenarios to modify in the PRA and reviewed plant experience for power level -- excuse me -- not power level but suppression pool volume, river water temperature and torus water temperature and came up with exceedance frequencies for meeting the temperatures of interest in the deterministic calculations that required NPSH.

MR. BANERJEE: Are we going to talk about these deterministic calculations later? Then we can just defer that part, because that's my -- my interest is in deterministic calc --

MS. BROWN: You're talking about --

MEMBER BONACA: I see from the TVA calculation, they're going to have --

MR. ANDERSON: Yes, separate.

MEMBER BONACA: -- talk specifically so we're going to talk about that.

MR. BANERJEE Thanks.

MR. ANDERSON: Okay.

MR. STUTZKE: Okay. With respect to the other initiators, the credit for containment accident pressure also affects station blackout scenarios, ATWS scenarios and the Appendix R scenario. Briefly, the Appendix R scenario is a loss of all the high pressure sources of feed water, the reactor feed water system, LPSI/RPSI. Then it's assumed that the reactor is manually depressurized and that single RHR pump is started in LPSI mode with it's heat exchanger also connected to service water.

As MEMBER BONACA pointed out, that seems to be the driving scenario for this. When it became apparent that that was, in fact, the driving scenario, we put on our risk analyst eyes and said, gee whiz, that looks like most BWR sequences to us. It's a classic high pressure scenario sequence, so therefore it was generalized to include all other types of PRA scenarios. By that I mean all types of initiating events that lead to -- that includes a loss of the main condenser heat sink less than two trains of suppression pool cooling and either depressurization or stuck open relief vale types of scenarios. So we tried to pick up those broad range of initiating events that are considered in the PRA.

However, you'll notice we did not look at the influence of the equipment configuration or the plant initial conditions on the need. Rather the assumption was the containment integrity is always needed, and that's just what we've done at Vermont Yankee because we have no evidence to let us back off on it.

Okay. When you look at the results for the containment accident pressure credit, they are like -- as you see here, that total is approximately 10 percent of the post-EPU core damage frequency. In other words, the post core damage frequencies throughout 2 times 10 to the minus 6 per year, so it's roughly 10 percent. Now we did use the licensee's success criteria stated, and we did our own risk calculation to confirm these numbers.

MEMBER APOSTOLAKIS: Can you explain the numbers a little bit. I mean the title is Containment Accident Pressure Credit. I mean what does all this mean?

MR. STUTZKE: What it means is if you were to lose the containment integrity for some failure mode, this is the core damage frequency attributable to that. So it's like looking at a before and after where before you don't need the credit and after, you do.

MR. RUBIN: This is Mark Rubin from the staff. It's not a conditional though. It includes the likelihood of losing integrity. Isn't that correct, Marty?

MR. STUTZKE: That's correct.

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

MR. STUTZKE: These are not conditional failures. It includes the probability that containment integrity is lost.

MR. BANERJEE: And what is that probability? How much of that is that?

MR. STUTZKE: It's approximately 10 to the minus 3. So I mean overall, the mode is --

MEMBER APOSTOLAKIS: Ten to the minus three. So you lose containment integrity and then I get, for that sequence, including the probability that I do. I get a core damage frequency of 1.7, 10 to the minus 7 --

MR. STUTZKE: That's right.

MEMBER APOSTOLAKIS: -- for all these

MR. STUTZKE: Yes. Literally, it would be some transient occurs, say, perhaps loss of main feed water, a subsequent failure of IPSI and RPSI demanding depressurization. Depressurization is successful, but now you've lost containment integrity, and that cavitates the pumps.

MEMBER APOSTOLAKIS: Then your last

sentence says the staff's confirmatory risk calculation produced -- so these are TVA results?

MR. STUTZKE: right. These are TVA results. We did our own calculations on the SPAR model to check the logic. The reason why is -- I'll point it out -- the TVA's PRA implemented a risk model, so it's a large linked sort of model. And we have no good way to check it, so we just built our own. The reason --

MEMBER POWERS: Were the seismic initiators all lumped into other transients?

MR. STUTZKE: No. And that's a good point. These are internal events only. We are not looking at any external sequence such as seismic.

MEMBER POWERS: One is puzzled then about the utility of this.

MR. STUTZKE: Say again?

MEMBER POWERS: One is puzzled about the utility then.

MR. STUTZKE: Yes. Well, the fact is that our procedures, our review process allows us to look at external events qualitatively and the licensee did look and decided that there were no changes in the seismic margins for the containment as a result of the power uprate, and so wouldn't -- one would not suspect that at post-EPU plants that the occurrence of an earthquake would change the fragility of that containment. Failure probability is the same before and after.

MEMBER APOSTOLAKIS: So this -- I mean, again, to understand it, this assumes a 20 percent uprate?

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: The plant is running, then for some reason you lose integrity of the containment, and then you have a transient or you have a --

MR. STUTZKE: No. It's --

MEMBER APOSTOLAKIS: -- a LOCA?

MR. STUTZKE: -- post transient. In other words, the initiating event would occur through the failures of systems. You get a demand to depressurize the reactor system. And at that time, when you depressurize, you need to establish the containment integrity parallel actions.

MEMBER CORRADINI: So if I might just say so. So the synergistic effect is with their deterministic calculations, then at some time when you needed an over pressure to make everything work, you didn't get it, therefore the pumps failed, therefore you take yourself down these pathways?

MR. STUTZKE: That's correct.

MEMBER CORRADINI: And this is the probability in any one of these pathways?

MR. STUTZKE: The frequency, yes.

MEMBER CORRADINI: Okay.

MEMBER KRESS: And the reason that other transients dominate is that their initiating frequency is the highest?

MEMBER CORRADINI: They're high.

MEMBER BONACA: some of this information is new, Martin, right, from the subcommittee meeting?

MR. STUTZKE: No, not deliberately.

MEMBER BONACA: No. Okay. Well --

MR. STUTZKE: Maybe I'm explaining it more --

MEMBER KRESS: Yes. You're explaining it differently but that's fine.

MEMBER BONACA: The question that I have is that the Appendix R sequences and the other transients, right, is lumped together?

MR. STUTZKE: Right. It's because I generalize --

MEMBER BONACA: Yes. That's right.

MR. STUTZKE: -- the sequence.

MEMBER BONACA: I understand.

MEMBER APOSTOLAKIS: And this slide includes the information you gave us on slide 5 regarding the number of RHR pumps?

MR. STUTZKE: Right. But remember, that's only for the large LOCA.

MEMBER APOSTOLAKIS: Five is only for the large LOCA?

MR. STUTZKE: Right. For ATWS station blackout and other -- the presumption is you always need to prevent --

MEMBER APOSTOLAKIS: You always need it. Okay. But this distinction for large LOCA is built into this?

MR. STUTZKE: That's correct. And so you drove it down pretty small.

MEMBER CORRADINI: If you hadn't -- now maybe that's the next question to ask you. If you hadn't graded it and made it more sophisticated, where would large LOCA likely fit in all of this, up an order of magnitude? Because the other transient, I wouldn't have expected it to go up two orders of magnitude to essentially -- you see what my question is?

MR. STUTZKE: Yes. And I would estimate

between one and two orders of magnitude.

MEMBER CORRADINI: Okay.

MEMBER BONACA: We need to, you know, for this presentation and the next two that we have, to focus on the Appendix R sequence oftentimes. I mean because that's really the critical one. That is -- and there -- reason why I say it's critical is that it's done on a best estimate, if I understand it. There is no single failure taken. There is no other consideration. So there it's difficult to say go back and do a best estimate calculation. Essentially, it's a realistic calculation. So the question is, why is it an acceptable sequence? The question is, you know, the licensee has made statements that says it's an unlikely situation that you have only one RHR, you're going to have two. We have to understand this logic. And hopefully, it will come through over the next presentations, the logic behind the statement that -- and also the logic behind the low value of risk under transients where you included the Appendix R sequence.

MR. STUTZKE: That's right. What I'm thinking of -- let me try to explain the 10 to the minus 7 number in some broad terms.

MEMBER APOSTOLAKIS: Is that the mean value?

MR. STUTZKE: Point estimates.

MEMBER APOSTOLAKIS: So how high would it be?

MR. STUTZKE: A quarter of magnitude higher.

MEMBER APOSTOLAKIS: But that's your -- just judgment.

MR. STUTZKE: I don't know. It's my guess.

MEMBER APOSTOLAKIS: Yes.

MR. STUTZKE: I mean I do have -- I did do parametric uncertainty for the total CDF, but I don't have the breakout for this sequence. My guess. Let me try to explain the 10 to the minus 7. If you look at a reactor trip frequency of about once per year, you need failure of your high pressure sources. That's about 10 to the minus 4. You can look at it as IPSI and RPSI would have reliabilities of two nines, meaning the failure probability is 10 to the minus 2 each multiplied together. Then the loss of containment integrity, as I told you before, is about 10 to the minus 3. And you can see, you've reproduced the minus 7 power, so it's believable.

MEMBER BONACA: It's -- which number are you discussing here? The other --

MR. STUTZKE: The bottom line.

MEMBER BONACA: The bottom line.

MR. STUTZKE: To give you an argument why 10 the minus 7 is plausible without the high powered risk assessment behind it.

MEMBER APOSTOLAKIS: But now if you had an earthquake, did -- you say they did a margins analysis?

MR. STUTZKE: Well, they argued their margins analysis is not changed, but no, margins analysis is not the seismic risk. It's something less.

MEMBER APOSTOLAKIS: But I wonder whether the margins analysis includes a possibility of all these events being coupled that you mentioned, 10 to minus 3, 10 to minus 4? I mean --

MR. STUTZKE: No, it won't.

MEMBER APOSTOLAKIS: It won't?

MR. STUTZKE: So then we're coming back to Dana's question. That would seem to be an important consideration here, would it not? Because I don't recall them -- the margins analysis is very stylized, and it doesn't really say, right?

MR. STUTZKE: Yes. It's stylized to the point where you couldn't calculate seismic CDF from it.

MEMBER APOSTOLAKIS: Right.

MR. STUTZKE: Maybe general -- let alone to pick on this aspect.

MEMBER APOSTOLAKIS: The moment you started describing it, I said, you know, I get 10 to the minus 3 from -- this 10 to the minus 4 from that. Well, I mean if there is an earthquake, then most likely you're not going to have those independent frequencies.

MR. RUBIN: This is Mark Rubin again from staff. Yes, Dr. Apostolakis, that's a very good observation. I would point out that as you said, the margins assessment is so stylized that it just identifies a couple pathways and equipment sets that will get you to safe shutdown. It may not even reflect other equipment that is important for reducing seismic risk but one might consider that the first order of seismic coupling would be the loss of off-site power initiation due to seismic, and the frequency of a seismic-induced loss of off-site power would be roughly an order of a magnitude or two below the other costs of loss of off-site power, which is the dominant vulnerability to these plants. Marty, is one or two order about right?

MR. STUTZKE: It seems about right.

MEMBER APOSTOLAKIS: So what you're saying is that yes, there may be coupling but then the earthquake that will do will have a very low frequency, so somehow you have to balance the two?

MR. RUBIN: I would say yes but to the modeling of the actual contributions where seismic would come into play, it would be lost in the noise with respect to the loss of off-site power frequency which is the primary driver to risk on this design. So if we included it, it would be --

MEMBER APOSTOLAKIS: The same thing.

MR. RUBIN: Yes.

MEMBER APOSTOLAKIS: The frequency --

MR. RUBIN: Two or three --

MEMBER APOSTOLAKIS: -- of the earthquake --

MR. RUBIN: -- figures --

MEMBER APOSTOLAKIS: -- would be so low then to --

MEMBER POWERS: I really don't follow the logic there, George. If we'll take those plants that have done a seismic PRAs that we have a frequency of about 2 times 10 to the minus 5 exceeding a safe shutdown earthquake?

MEMBER APOSTOLAKIS: I don't remember, Dana, but you may be right.

MEMBER POWERS: Okay. So let me -- so could we argue that an earthquake that threatens the integrity of the plants have roughly 2 times 10 to the minus 6?

MEMBER APOSTOLAKIS: Right.

MEMBER POWERS: And the potential for 2 times 10 to the minus 6 earthquake of causing a station blackout, seems to me, is 1.

MEMBER APOSTOLAKIS: And then?

MEMBER POWERS: Well, I mean the numbers were all order a magnitude bigger than anything that you've got up there.

MR. RUBIN: This is Mark Rubin again from the staff. I can only give you a partial answer to your question, because of the limitations to the methodology that was used to assess seismic risk and vulnerability on this plant. The safe shutdown earthquake is part of the design basis. The seismic margins assessments are typically done at a higher g level loading. However, the g level required to give you loss of off-site power but not station blackout is much less, .05 g, something along that order. So the frequency would consequently be higher, but the equipment is quite robust and has been demonstrated in the seismic margins analysis to give you capability of about .3 g or well above.

MEMBER POWERS: But that's -- I mean all you're saying is that as long as the earthquake's below the safe shutdown earthquake, the on-site power will work. And I'm saying, okay, yeah, what happens when you exceed that, and what's the probability of exceeding that? I mean I don't know for this particular plant, but the median of those plants that have done seismic PRAs, it's about 2 times 10 to the minus 5th. So say it's 10 to the minus 6th. Okay, now -- but still in order of magnitude more than any number on that charge on there.

MR. RUBIN: Well, we don't have a seismic PRA for this design nor is one required unless the change can be demonstrated to require a very extensive analytical treatment. This is not a risk-informed application, so basically we'd be looking for issues related to adequate protection and at a screening which is somewhat coarse to make that determination. I thin what Marty's done is made a determination based on the licensee's qualitative assessment that there are not such overriding or significant seismic concerns that it would significantly change the conclusions and findings. But again, the on-site emergency AC power system is assessed for well beyond SSC seismic loadings in the safe shutdown analysis part of seismic margins. But, of course, at some g level, they will indeed fail and you'll lose both off-site power and AC. That's absolutely correct. So your observation is true.

MEMBER POWERS: I mean -- see, the question is is it okay to have pumps that need containment pressurization in order achieve that positive suction head? It seems to me we have looked from a risk perspective at the wrong classes of accidents, by an order of magnitude, we've looked at the wrong classes of accidents.

MEMBER APOSTOLAKIS: I mean we have heard numbers, even here in the last five minutes. It doesn't appear to be too difficult to go back and look at some of these numbers and see -- and make a case but maybe, you know, the number is higher or lower or the same.

MR. STUTZKE: I would argue a little bit differently. When you look at the station blackout, what you're talking about is once off-site power is recovered, okay, once you're out of the blackout, you need the over pressure credit. Okay? During a station blackout, you don't need the credit or not because you can't run the LPSI pumps anyway. So who cares? Okay? Like this -- like the issue with seismic risk is that if I have a larger earthquake, I will generate an off-site -- loss of off-site power, and I may create a LOCA somehow. Okay? And during that -- in order to mitigate that LOCA, then I need to run low pressure systems, and I need to make certain that they're okay. So the question is can I make a LOCA at the same time I've reached the containment because of the earthquake? Okay? And my argument would be you need a really big earthquake to break the containment, well above the SSE. They're very robust structures like this. Break the reactor coolant system piping due to a LOCA requires another pretty good size --

MEMBER APOSTOLAKIS: So essentially, again, the argument comes down to what is the frequency of that huge earthquake?

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: And Dana mentioned 2 times the minus 5. He was willing to go down to 10 to the minus 6.

MR. STUTZKE: But that's --

MEMBER APOSTOLAKIS: But you are arguing

that even that is a high number?

MR. STUTZKE: That's a high number because the capacity, you know, the seismic capacity for things like the containment or the LOCA piping itself is on the order of 2 to 5 g's. It's well above the safe shutdown earthquake.

MEMBER APOSTOLAKIS: For this plant, 2 g's?

MR. STUTZKE: For seismic fire, not the SSE saying to actually break the containment, but in response, it's a pretty large number.

MR. RUBIN: As part of this -- Mark Rubin, again -- as part of the seismic margins analysis, that's what they do. They validate fragility of the essential components needed to demonstrate the two safe shutdown paths. And typically the components Marty just mentioned come nowhere near to being the limiting components where you might run into some difficulties. There are a number of others with much, much lower fragilities.

MEMBER CORRADINI: Like what, Mark, for example -- gee, it's been a long time. There may be some instrument racks, relays that shatter when they don't use rotary relays, a whole number of things.

MEMBER APOSTOLAKIS: Relays are a big

problem.

CHAIRMAN SHACK: And again, it's the delta we're looking at. I mean if the seismic, you know, will the EPU make a difference to the seismic risk? You know? I mean if you're losing all this equipment whether you've got an EPU or not, you're in trouble. You know? This is focusing not on the -- again, it's not an absolute risk -- I think Dana's right. In absolute risk terms, seismic dominants this point. The question is whether that's really affected by the EPU or not. But we have to move on.

MEMBER BONACA: We need to move on, yes. We also need to take a break soon, so.

CHAIRMAN SHACK: Maybe this is a good point just to --

MEMBER BONACA: Should we stop now and take a break.

MEMBER KRESS: Let's finish the risk.

MEMBER BONACA: Let's finish this part here and then --

MR. STUTZKE: Human reliability. Okay. Glasses on. Okay. When the licensee looked at how the impact of the EPU changed post operator human reliability, they did go back to their math calculations and looked at how much time was available for operator response, and you know that the time gets shorter. And they also looked at how that affected their estimation of the cognitive error portion of the human reliability. Now they're not running a time reliability correlation, so a small change in the time doesn't necessarily change the cognitive error probability. That's because time has discretized it's bin, and if it doesn't change from one category to the other, there would be no change from the probability. They did recalculate some of the events using the EPRI HRA calculator. They're using cost-based decision tree. In some cases, when they judged the time, it's not the important driver, but there may be other causal factors. In other cases, they used an HCR for time-sensitive types of errors.

MEMBER APOSTOLAKIS: So what was the shortest time and how much shorter did it become?

MR. STUTZKE: I knew you would ask. Well, for an example, okay, operator fails to inhibit ADS during an ATWS scenario. Okay? Fourteen minutes pre-EPU, 12-1/2 minutes post-EPU.

MEMBER APOSTOLAKIS: That's the shortest?

MR. STUTZKE: That's the smallest sort of change, 95 seconds versus 80 seconds, no change, no change, no change.

MEMBER APOSTOLAKIS: Oh, 95 seconds? What?

MR. STUTZKE: Okay. For example, he fails to inhibit ADS when he has an isolated reactor vessel.

MEMBER APOSTOLAKIS: Right.

MR. STUTZKE: It changes from 95 seconds to 80 seconds.

MEMBER APOSTOLAKIS: And they were able to tell us how much the probability changes?

MR. STUTZKE: Yes.

MEMBER APOSTOLAKIS: That's a remarkable achievement.

MR. RAZZAQUE: I think --

MR. STUTZKE: But again, it's looking at small changes.

MR. RAZZAQUE: I think the point is numbers that short, the probability of error is very, very high to start with, and it's reflected in the baseline as well as the delta change. And we wouldn't expect a difference in HRA numbers to be realistic. It would be within the uncertainty bounds of the modeling techniques.

MR. STUTZKE: One thing I will --

MEMBER APOSTOLAKIS: So why are you trusting the HCR? I mean this staff has never reviewed it?

MR. STUTZKE: No. That's not true.

MEMBER APOSTOLAKIS: Has it?

MR. STUTZKE: NUREG-1842 --

MEMBER APOSTOLAKIS: No --

MR. STUTZKE: -- is a comparison of the known HRA methods.

MEMBER APOSTOLAKIS: Yes. But that was just with practices. I mean there was never any review of an actual model. It was just a discussion of they do this, they do that.

MR. STUTZKE: That's true.

MEMBER APOSTOLAKIS: But nobody really looked at how they do it. But we have already --

MR. STUTZKE: Well, I mean the --

MEMBER APOSTOLAKIS: -- an SRM to address this.

MEMBER BONACA: The only time that it is reported in the SCR, and we discussed it at the subcommittee, was the containment, that atmospheric dilution time. It went from 42 hours to 32 hours.

MEMBER APOSTOLAKIS: That's fine with me.

MEMBER BONACA: Well, that's right. We were told that nothing else really changed significantly and so. We didn't see that table that you're quoting.

MEMBER APOSTOLAKIS: Yes. The table is very good. I don't know why -- is it part of the public record now?

MEMBER BONACA: No.

MR. STUTZKE: It'll be part of the 120 percent safety evaluation.

MEMBER APOSTOLAKIS: We can't have that now?

MR. STUTZKE: I think we can arrange something.

MEMBER APOSTOLAKIS: I think the rule is if you refer to a document, it becomes part of the record.

MEMBER BONACA: I mean this is new information.

MR. STUTZKE: Well, my point is this, let's flip on to slide 9. It's all of the human errors that they changed for related to ATWS, these are the ones: ADS inhibition, isolated/non-isolated reactor vessels, dropping water down to top of active fuel, running slicks and backup scram.

What I think is important about this is shown on 10. It's not necessarily what the actual numbers were. What we need to know from a non-risk informed license amendment is did human failure events become more or less significant as a result of the power you uprate. As you look at the bottom half here, these are human errors that were significant prior to the EPU and they remained significant post EPU. The ones with the asterisks are the ones that had their probabilities changed.

I think what's more interesting about this, first of all, significant is as defined in Reg Guide 1-200 that says it has a raw value bigger than two or a fussel vessely bigger than 5 e minus 3. What's more interesting about this is some human events became significant as a result of the EPU controlling level using HPCI-RCIC. Initiating depressurization -- that's because of the influx of the enhanced CRD success criteria. These actions, even though their probabilities did not change, became more important because the structure of the model changed.

So I think that's the real message here, and to --

MEMBER APOSTOLAKIS: So what -- in terms of the decision that the Agency is facing, what does that mean? It's just information?

MR. STUTZKE: It's information. When I

get to the summary slide, my conclusion is that the changes of these human error probabilities is a small influence on the total change of the core damage. What's really driving it is the change in success criteria for enhanced CRD. And that's what we've never seen.

MEMBER APOSTOLAKIS: Now we keep saying this is not a risk-informed application. Of course, it's true. But how does the human performance -- how is the human performance taken into account in the non-risk-informed -- not risk-informed application? It can't be, right? I mean unless you go through this, you will never really see anything because you don't address that issue. Not you personally.

MR. STUTZKE: That's true.

MEMBER BONACA: I'm really troubled by it. I mean we had a full two days' of committee meeting that we asked questions about time, and we had -- this information wasn't provided. We didn't see the table. We didn't discuss the table. In fact, we asked specifically the question, and the answer was the only time that it is affected is the one for 42 hours and 32 hours.

MS. BROWN: I believe we said at that point we were addressing the most significant time.

Through the presentation, we had other examples where the time had changed.

MEMBER BONACA: Yes. But it was verbalized and said, oh, yeah, but it is nothing. I mean I was there so I think I --

MS. BROWN: Yes, sir.

MEMBER APOSTOLAKIS: You were probably chairing it.

MEMBER BONACA: No. I'm only saying it because this introduces many different kind of discussion, and I -- you know --

MEMBER CORRADINI: Can I ask you a question just to verify. Just to repeat what you said, because I thought I -- what I remember is similar -- is that these change in the human performance are small compared to the success criteria relative to the prior discussion we had in terms of internal events driven by this containment to over pressure or I'll say containment integrity issue --

MR. STUTZKE: That's correct.

MEMBER CORRADINI: So there are still effects here, but these effects are swamped by the previous effects? Am I --

MR. STUTZKE: That's correct.

MEMBER CORRADINI: Okay. And again,

that's what we did here. I think it's --

MEMBER MAYNARD: For my clarification, these time changes you're talking about are really done at 120 percent, not the 105 percent? Is that --

MS. BROWN: Yes, sir.

MR. STUTZKE: Correct.

MR. RUBIN: And what's -- Mark Rubin again -- what's interesting from the assessment of this plant is normally for the BWR power uprates, the only place we see an impact is from the timing effect of the operator responses. And we -- so we look at it in some amount of detail. And you're seeing more detail here than perhaps was given at the subcommittee, and I apologize for that. As was mentioned, our analysis doesn't -- was done at 120. These same conclusions would not necessarily apply at 105 percent.

MEMBER BONACA: Yes. I understand that but the point is that nothing specific was presented about the 105.

MR. RUBIN: Right.

MEMBER BONACA: Everything was presented about the 120 with a generic statement that there were no significant changes and is applying to the 105 percent case, too. So the distinction really was not made.

MR. RUBIN: Yes, sir. What drives the risk impact, I think about 90 percent of it is the change in the CRD success criteria capability which si a hardware issue. That's kind of unique for a BWR uprate. And that was what Mr. Stutzke focused on, and if we were misleading or incomplete in any way, I apologize. This is about 10 percent of the contribution.

MEMBER APOSTOLAKIS: So, again, come back to the main conclusion that it's the acceptance -- I mean the success criteria that really dominate the --

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: And the impact of those changes in the success criteria is already part of the review of the traditional deterministic analyses?

MR. STUTZKE: No.

MEMBER APOSTOLAKIS: No?

MR. STUTZKE: Only for the containment accident pressure curve.

MEMBER APOSTOLAKIS: I don't understand this. I mean it's a not risk-informed application because the rule is not risk-informed, right? So presumably, the major impacts of the power uprate are investigated in the traditional -- you know, in the rule -- the rule --

MS. BROWN: Yes, sir.

MEMBER APOSTOLAKIS: -- and the regulatory guides.

MS. BROWN: Yes, sir. We have a different group that reviews the --

MEMBER APOSTOLAKIS: Right. I understand that.

MR. RUBIN: I think I can provide perspective for you, sir.

MEMBER APOSTOLAKIS: So now we have -- let me finish the thought here. Here comes a risk analyst and says from the PRA perspective, I have changes in the success criteria and I have changes in the human factors or the human performance. We have agreed that the changes in the human performance are not captured by the rule. When I say the rule, I mean the deterministic evaluation. Are the changes in the success criteria or the impact of those on the plant captured by the rule so at least I will feel better given the conclusion that Marty's giving me that the impact of the human factors is secondary to the impact of the success criteria.

MS. BROWN: Sir. Are --

MEMBER APOSTOLAKIS: Are these captured?

MS. BROWN: -- are you asking whether or not the staff, the human factor staff went back and used these risk insights --

MEMBER APOSTOLAKIS: No.

MS. BROWN: -- as part of their review?

MEMBER APOSTOLAKIS: No. What I'm saying is we have two conclusions that -- or two messages that I, at least, perceive from Marty. One is if I were to do a PRA, another uprated plant, for the uprated plant, I would have to revisit the success criteria, and I would also have to look at the performance of the humans, right? But this is not a risk-informed application.

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: So in principle, I can completely ignore what you're saying and make my decision using the rule. The question is now are parts of what Marty is saying captured by the rule itself so I will feel better that at least something has been done about these things? And we have agreed that the human performance is not captured, because we don't look at timing and all that in the rule. And the question now is the success criteria, when you go form two to three or from three to two, would that be investigated within the rule so I'll feel better that, you know, at least we caught what the PRA says is dominating?

MS. BROWN: Mark?

MR. RUBIN: Yes, sir. Tough question. I'll try to give a tough answer if I can. Having come from both the deterministic teach analysis side and PRA, I'm going to give you a bifurcated answer. The answer to your question is yes and yes. But you have to differentiate design basis analysis requirements from severe accident beyond design basis success criteria and plant response and capability. Changes in success criteria due to the power uprate will indeed be reflected as they impact the Chapter 15 design basis accidents and their acceptance criteria.

For example, if success criteria for a large or small break LOCA changed from one to two pumps, that would be reflected in the staff's safety analysis, and there would be thermohydraulic calculations that would either be reviewed or possibly confirmatory analysis to verify it. So in DBA space, it would be reflected. The reason the CRDs are not reflected changes in success criteria in the steps traditional deterministic response is they're not a safety-related system and are counted on to respond to design basis accidents. Though as we all know, they have considerable capability, as the fire at this plant showed us, to respond to a lack of high pressure makeup. But that capability is only reflected in the plant's PRA because it's beyond design basis, and they're not safety systems.

In PRA space, we try to show the realistic capability of the success criteria for sequences that go well beyond design basis.

MEMBER BONACA: I think this is becoming an extension of the subcommittee meeting and we had a problem.

CHAIRMAN SHACK: Yes. We need to get to the conclusion.

MEMBER BONACA: That's right. I mean we're -- this is new information --

CHAIRMAN SHACK: One response to your question, George. You know, it's important but it, you know, it's changed the CDF by, you know, 1.8 times 10 to the minus 6. In deterministic space, you know, you're not looking at changes like that.

MEMBER APOSTOLAKIS: No. But that was not really my question.

CHAIRMAN SHACK: Well --

MEMBER APOSTOLAKIS: My question is because we keep -- I mean it's not just --

CHAIRMAN SHACK: Well, no --

MEMBER APOSTOLAKIS: -- the operate. It's also the license renewal --

CHAIRMAN SHACK: Let's move on to the slide.

MEMBER APOSTOLAKIS: We have rules --

CHAIRMAN SHACK: We just got to move on.

MEMBER APOSTOLAKIS: We have rules that were promulgated before risk information was used to the extent it is being used now by the agency. And in order not to open up again the rule and start revising it, we have agreed to go with those rules, even though they're kind of old, and have the PRA information as an additional piece of information. And I'm wondering how much of the insights that we gain from the PRA are, one way or another, covered already in some deterministic way. That was really the question, not the 10 to the minus 7. I mean there you can argue, you know, whether it's correct or should be higher or low.

CHAIRMAN SHACK: Okay. We need to move this --

MEMBER APOSTOLAKIS: And then Mark's answer really focused on the design basis issue, right? The basis of the approval is whether your design basis is still acceptable.

MR. RUBIN: I would say it focused on both, sir, because the deterministic analysis looks at the design basis accident response capability changes while PRA looks at everything. Well, everything is too strong a statement.

MEMBER APOSTOLAKIS: No. It does. It does. It does.

CHAIRMAN SHACK: In the ideal world, it does.

MR. RUBIN: Yes, sir.

CHAIRMAN SHACK: Just leaves out seismic. Okay. Let --

MEMBER APOSTOLAKIS: No. PRA doesn't.

CHAIRMAN SHACK: Okay. Let's move on.

MEMBER APOSTOLAKIS: The humans do.

CHAIRMAN SHACK: Let's try to wrap up this prior to the end.

MR. STUTZKE: Let me move on. Briefly, about PRA quality, the conclusion is that the model has adequate quality to support --

MEMBER APOSTOLAKIS: But, you know -- excuse me, Marty -- because there is another session tomorrow. We're going to look at Regulatory Guide on fire protection and similar issues come up there.

Okay? So it's a bigger issue than just the Browns Ferry.

MEMBER BONACA: Let's get to the last -

MR. STUTZKE: Yes. Just go to the last slide.

MEMBER APOSTOLAKIS: Go to the one after last.

MEMBER BONACA: To the bottom of the last --

MEMBER APOSTOLAKIS: Go to the thank you.

MR. STUTZKE: Okay. So you can see the changes in the post-EPU risk metrics for all the units. Summarize again -- it appears the largest, in fact, is the change in success criteria on enhanced CRD flow, then the CAP credit, and then finally the HRA, the point being we have not found any speckle circumstances that rebut the presumption of adequate protection afforded by compliance with the Regulations.

MR. BANERJEE: This is all for 120 percent?

MR. STUTZKE: Yes, 120 percent. Okay, Mario. Thank you.

MEMBER BONACA: Why don't we take a break.

CHAIRMAN SHACK: Okay. Be back at five

of.

(Whereupon, off the record at 10:44 a.m. and back on the record at 10:58 a.m.)

MR. CROUCH: On the record. Before we get started on the next discussion, I'd like to go back and clarify a point from an earlier question raised. The question about the injection of hydrogen, would we be running it, the cycle, unmitigated or how would we handle it and we responded we would increase the hydrogen so it would be mitigated, we conferred back with your staff at the plant and we want to clarify that. That's not what the plans are. The plans are that we would run at a low level of hydrogen, the same as what we're running on 2 and 3, until we do the noble metals applications which is going to be done in a mid cycle application after approximately 90 days. You have to wait a short period of time for the proper layer of oxidation to build up on the fuel. So I just wanted to clarify that before we went on.

We have with us today Jim Wolcott and Bill Eberley who are our managers responsible for containment overpressure analysis and I will turn it over to Jim.

MR. WOLCOTT: Good morning. Today's presentation is going to focus on the conservatisms that are in our licensing basis, MPSH analysis, that we showed and discussed at the subcommittee two weeks ago, a comparison of Browns Ferry's COP credit to the rest of the industry. We'll show some realistic analyses of MPSH and COP dependency and we'll discuss a little bit more about the risk evaluation that we used to determine COP risk based on probability.

This is an ECCS schematic that's simplified to show the parts of the ECCS system that are of interest to an MPSH analysis. Brown Ferry has four RHR pumps which are shown in blue there and each one of them has its own RHR heater exchanger that it's lined up to. So there are four RHR heater exchangers.

The RHR system takes suction from the suppression pool and it performs several functions. It can perform core cooling which is labeled LPCI there. It can perform containment cooling by spraying either the drywell part of the containment or the torus part of the containment and it can return water directly to the suppression pool for direct suppression pool cooling.

We also have four core spray pumps which are shown in yellow on the right-hand side of the diagram and they also take suction from the suppression pool and they just perform a core cooling function.

This diagram also shows our ECCS strainers symbolized on here. We have GE stacked disk strainers. There are four of them and they are on a common ECCS ring header. So all of our pumps share all of the strainers through a common header. Next slide.

The MPSH analyses that we presented for Unit 1 are done at 120 percent of original licensed thermal power and that would bound any result we would expect to see at 105 percent. There are four design basis events or licensing basis events at Browns Ferry that require containment overpressure in order to satisfy vendor's required net positive suction head for the RHR or core spray pumps and that's the loss of coolant accident, anticipated transient without scram, station blackout and Appendix R fire. Next slide.

This slide shows a table of containment overpressure magnitudes and durations that are used by other BWRs that are licensed for extended power uprate. The two columns to the right there are the most important ones. They show the peak containment overpressure required for a LOCA and the duration column shows how many hours that's needed for. Browns Ferry is in the bottom row there and as you can see, what Browns Ferry is needed is in line with other uprated plants.

MEMBER BONACA: But the Browns Ferry ones you are listed here, the bottom, is the LOCA, the long-term LOCA.

MR. WOLCOTT: Yes. These are all LOCA comparisons.

MEMBER BONACA: Okay. So you have not -- You're talking about the other special events later?

MR. WOLCOTT: We'll show charts of the special events. As far as comparison is concerned, analyses of the special events for containment overpressure is somewhat new and so all these plants wouldn't have anything docketed one way or another on special events. So we just chose that one event.

MEMBER BONACA: I understand.

MR. SIEBER: It's unlikely.

MEMBER BONACA: It serves the purpose, but you will talk about the Appendix side of the scenario.

MR. WOLCOTT: Yes.

MEMBER BANERJEE: Was Appendix R considered for Vermont Yankee?

MR. WOLCOTT: Yes, starting at Vermont Yankee is when power uprate licensing started to look at these special events in detail and Appendix R was considered for Vermont Yankee.

MEMBER BANERJEE: So when you show your results, would you please put it in the context of what we saw at Vermont Yankee as well or somebody could?

MR. LOBEL: This is Richard Lobel from the staff. For Vermont Yankee, are you questioning Appendix R?

MEMBER BANERJEE: Yes.

MR. LOBEL: Appendix R, they did not require containment overpressure. They went back and reassessed and found that they could take credit for a second service water pump and with the addition of another service water pump, they didn't need containment overpressure for Appendix R.

MEMBER BANERJEE: Thanks.

MR. LOBEL: Or for station blackout. They needed a little for ATWS.

MEMBER BANERJEE: So the only events they needed it for was LOCA.

MR. LOBEL: LOCA and a little bit for ATWS, less than the value that's up there for ATWS.

MR. WOLCOTT: Next slide. We're going to present event analysis for two of the events, LOCA and Appendix R. That's the same two events that we looked at at subcommittee. We have these slides sequenced such that we can sequence different parameters onto this graph one at a time. So there are like four slides there that sequence things off and on.

I'll start by talking about the same thing that we presented at subcommittee. That's kind of our base case. The top red line there is the amount of containment pressure that we expect to see in a LOCA event based on the long-term analysis by using assumptions that drive the containment pressure to its minimum value.

MEMBER ABDEL-KHALIK: Excuse me. How would this red line change if the analysis were done at 105 percent power?

MR. WOLCOTT: It would be a little bit lower.

MEMBER ABDEL-KHALIK: Okay. So why do you say the 120 percent analysis is bounding for 105 percent?

MR. WOLCOTT: Because the other two lines would also be lower by the same amount. The difference between the power levels for this line has to do with the vapor pressure contribution from the pool and that vapor pressure contributes to containment pressure and it takes away from the MPSH equation by the same amount really because they're both -- The vapor pressure term is really in both of those and so the margin between, say, the red line and the green line as you change power levels would not get smaller. The green line would go down and the red line would go down, too.

MEMBER ABDEL-KHALIK: So you have calculations to support that the red line would go down by a smaller amount than the green line, for example.

MR. SIEBER: By the same amount roughly.

MR. WOLCOTT: We have the red line, I think, for 105 percent, but this analysis for Unit 1 was done only at 120. So I'm giving a little bit of change judgment when I say that.

MR. SIEBER: Now that step change at eight hours, that's a change in the calculational method, is it not?

MR. WOLCOTT: That's correct. So moving on down to the green line, that would be the amount of containment pressure in psia that we need to add into the net positive suction head equation for a core spray pump in order to just equal for the required MPSH.

The disk continuity that's in the middle of that green line there is a reflection of the vendor's time-dependent MPSH requirements and the way we've implemented that is we've just chosen to implement it in steps. So at eight hours, we go to the 24-hour MPSH.

MR. SIEBER: Yes.

MR. WOLCOTT: We just took it in discrete steps. So that's not a real phenomena. It's just a change in the rules to make it more difficult to meet the MPSH requirement if the duration of the event reaches eight hours.

The blue line down is the same information for RHR pumps. It's significant here that in the licensing basis LOCA the RHR pumps don't require containment overpressure. The dotted line across the middle of the chart is atmospheric pressure at Browns Ferry. So any of these lines that are below that dotted line represent not needing containment overpressure.

MEMBER CORRADINI: So can I just say back to you what you just said so I have it right. If we were to go from 120 back down to 105, the green line would fall below the dotted line.

MR. WOLCOTT: No, the green line would still be above the dotted line. What I was trying to describe there is that the green line and the red line would fall together.

MEMBER CORRADINI: Right. That's what I remember when Said asked the question about it. But the green line would still stay below the dotted line. So let me just ask a different question because I'm trying to unwrap it. So this is a design basis calculation.

MR. WOLCOTT: Yes, sir.

MEMBER CORRADINI: Okay, and the red line is representing the lowest that the containment pressure would be.

MR. WOLCOTT: Correct. By selecting assumptions to drive the pressure to its lowest rather than its highest.

MEMBER CORRADINI: Okay. And then in the -- I should have this written down. I apologize. I don't. Depending on the sequencing, you need the containment spray as the limiting one under this time sequence. Is that correct?

MR. WOLCOTT: The containment is being sprayed in this event.

MEMBER CORRADINI: Right.

MR. WOLCOTT: Because it's one of the things that drives that red line down. Maybe I misunderstood.

MEMBER CORRADINI: The core spray.

MR. WOLCOTT: The core spray. Yes, sir. The core spray pumps are the only pumps that require containment overpressure just because of the difference in what their required MPSH is. So the RHR pumps don't require containment overpressure for this event in order to meet the vendor's MPSH. That's significant because the RHR pumps are a lot more important to safety. They're able to cool the core and the containment at the same time; whereas, the core spray pumps can just cool the core.

MEMBER CORRADINI: So just one more summary question to get back to what Tom was asking at the subcommittee meeting which is you're defining degradation in eight hour and 24 hour increments and then also the degradation is assumed not -- I'm not to restate what he asked in the subcommittee which is it's not a degradation in flow. It's just essentially a failure to perform.

MR. WOLCOTT: No. The time dependency would be cumulative wear and tear on the pumps caused by the cavitation. So in this time duration, there's no performance issue with that degradation.

MEMBER CORRADINI: You would expect --

MR. WOLCOTT: In other words, the head flow performance is expected to stay the same.

MEMBER CORRADINI: Thank you.

MEMBER BANERJEE: I guess the issue that came up at the subcommittee meeting was how inventory and energy was being partitioned in these calculations which we, if I recall, were done by GE or some part of them anyway. So there was implicit in this some maximum fraction of the energy that was going to into heating up the pool and some portion of the inventory that was going into the containment.

So depending on how you assign or partition these, you could get different answers. I guess the question still remained in my mind after the subcommittee meeting as to what was the basis for this partitioning. What was giving you the lowest containment pressures and the highest pool temperatures.

MR. WOLCOTT: Let's go to the next slide and talk about that.

MEMBER BANERJEE: Okay. And this is true for all of the cases we're talking about.

MR. WOLCOTT: The next slide may go some way to answer that question. What we've added here then is what is now the highest red line and that would be containment pressure we would expect for the exact same event sequence by taking assumptions, one of which is how we partition the energy flow there. We take all the assumptions so as to maximize containment pressure.

MEMBER BANERJEE: Minimize or maximize.

MR. WOLCOTT: The upper one is maximize.

MEMBER BANERJEE: Okay. Right.

MR. WOLCOTT: So as we range our assumptions from assumptions that drive it to its minimum to those that drive it to its maximum, this shows us the range of results that you get in the actual containment pressure.

MEMBER BANERJEE: And what about the CS range? Presumably when you go to conditions where the energy maximized going into the containment, it's minimized going into the pool. I don't know exactly how you're partitioning this. I'm just guessing.

MR. WOLCOTT: I plotted that out and there is almost no different in the pool temperature here. So from an energy standpoint, it's not so much as a partitioning in energy just from what I looked at, but rather assumptions such as how much noncondensable gas is present in the containment to start with which varies over the operation of the plant. It's assumptions like that that make the big difference between whether you get minimum pressures or maximum pressures.

MEMBER BANERJEE: So the partitioning of energy doesn't significantly affect the pressure or the pool temperatures. It's just the assumptions regarding noncondensables which primarily affect it.

MR. WOLCOTT: Yes. Dilip from GE is going to talk about this a little bit. When we plotted this out, there was very little difference in pool temperature. So I didn't even bother to put it on here.

MR. RAO: Dilip Rao from GE. For this time duration and the order of hours, all of the energy within the vessel internals as well as the inventory and the fuel has been transferred from the vessel into the suppression pool and into the containment air space.

MEMBER CORRADINI: So just to follow up your question to Sanjoy's question, so it is where the noncondensables are that's causing this red line to move that much. That's what I -- To get to the nub of it. I mean I think Sanjoy's question was that he thought it was energy partition. I assumed that, too. Is it mainly where the noncondensables are?

MR. RAO: Yes. The upper line essentially reflects the fact that we assume an initial relative humidity in the drywell of 20 percent versus 100 percent for the lower red line. So the presence of more noncondensables in the drywell would then result in a higher pressure.

MEMBER BANERJEE: So all the energy is assumed to go into the water in the pool?

MR. RAO: The energy is going to be flushed out of the reactor vessel and initially will enter the drywell air space. A fraction of that is assumed to be directed immediately and directly into the suppression pool. The rest of it is assumed to mix with the drywell atmosphere and then flow into the pool, the liquid then flow into the pool.

MEMBER BANERJEE: But then what fraction is initially assumed to go into the water and how much into the atmosphere? What's that fraction?

MEMBER CORRADINI: There's no bypass. I think the way I interpret his --

MEMBER BANERJEE: No, the initial peak. So there are two stages to this. So let's talk about the first ten minutes. What fraction is supposed to go into the water and into the air?

MR. RAO: The assumption we have is that

100 percent of the water coming out of the LPCI is sprayed into the drywell and this is for the purpose of minimizing containment pressure air and 40 percent of the hot water from the vessel is assumed to mix with the drywell before flowing down to the pool.

MEMBER BANERJEE: What about the steam?

MR. RAO: This is the total energy from the break.

MEMBER BANERJEE: I'm still not understanding. How much of the total energy that's coming out in this LOCA or whatever event is going into the water in the pool and how much of that energy is going into the atmosphere? Maybe I'm missing something, but --

MR. LOBEL: This is Richard Lobel from the staff. Maybe I can try to approach it from a different way. You have to understand that this is all one calculation. The reactor vessel and the containment are both modeled together. They're coupled and the break is going to put the mass and the energy out into the drywell and then the containment model is going to determine how much stays in the drywell and how much goes to the suppression pool. So the fraction that goes one place and another is controlled by things like volume and break flow and humidity and those kinds of things that are put into the model and the differences that you see in the two red lines are just the different assumptions that are made. But all the energy and mass is coming out into the drywell first for a LOCA.

MEMBER BANERJEE: Thanks for that. I think that's very helpful. But now when you exercise this model, what fraction is going into heating up the water? I realize that you're not doing two separate calculations which are actually bounding calculations separately for the pool temperature and the pressure. You're doing one calculation which has a model in it and this model by some magic is doing this partitioning based on some science somewhere. But what is the fraction --

MR. LOBEL: The simple -- flow and heat transfer --

MEMBER BANERJEE: All right. But what is the fraction that's coming into the liquid and how much is staying? I'm just asking for a result of that model, that calculation. How much is going into the water and how much is going into the atmosphere?

MR. RAO: Forty percent of the mixture is going to stay -- is going to be mixed with the atmosphere and then flow into the pool.

MEMBER BANERJEE: Is that the energy or the mass or what is it?

MR. LOBEL: It's the energy.

MEMBER BANERJEE: So forty percent of the energy is going into the pool and 60 percent is staying in the atmosphere. What happens if it's 50 percent?

PARTICIPANT: (Off the record comment.)

MEMBER BANERJEE: Well, whatever the number is? Let's change it by a factor of 25 percent. Let's say your model is wrong by 25 percent. What happens then?

MR. RAO: I don't believe we have the results for that here.

MR. LOBEL: Well, let me --

MEMBER BANERJEE: Would you get a higher pool temperature and a lower atmospheric pressure?

MR. LOBEL: This is Richard Lobel with the staff again. I think the question isn't so much the partitioning. Again, it gets back to the assumptions you make. You make assumptions that force the energy to be one place or another. For example, for the peak pressure calculation, you make assumptions that are going to maximize the pressure. For an MPSH calculation, you make assumptions that are going to minimize the pressure and you bias us the assumption. They bias the assumptions in a conservative way and so it's you're not aiming for a certain fraction of energy one place or another. You're biasing the assumptions to give you the high suppression pool temperature and the low containment pressure.

MEMBER BANERJEE: Yes. Thanks, Rich.

MEMBER CORRADINI: Let me just try --

MEMBER BANERJEE: I understand that. What you're really doing is you're playing just with the initial conditions because that's all you can play with.

MR. LOBEL: Well, and some of the assumptions in the calculation, too.

MEMBER BANERJEE: Right.

MR. LOBEL: The other thing to remember too is that TVA can correct me if I'm wrong, but my understanding is that the suppression pool temperature is much more important than the pressure and MPSH calculations because of the behavior of the vapor pressure curve. A little change in temperature reduces MPSH margin more than a linear change in the pressure. So the temperature has a bigger effect. So though --

MEMBER BANERJEE: You're scaring me even

more now by saying that. The reason is --

MR. LOBEL: But you're doing one calculation.

MEMBER BANERJEE: I realize that.

MR. LOBEL: And where there is a parameter that can affect both the pressure and the temperature you usually aim it to maximize the suppression pool temperature because that has the bigger effect.

MEMBER BANERJEE: What you have is, if I understand this, correct me, let me just give you back what you said, you have, all of you, and you can correct me, a code of some sort into which you put some inputs. You have control over these inputs. So you can play with them. But within this code is hardwired some model which includes the flows from the drywell to the wetwell and the mixing or whatever.

MR. LOBEL: No, it's not hardwired. It's determined by the assumptions you make, assumptions for the geometric flow path through the bends and the downcomers for the short term, the heat exchanger characteristics that control the temperature out in these times, the volumes, the humidity that you started with, the suppression pool temperature you started with. All those things are inputs that you biased to give you whatever result you're after.

MEMBER BANERJEE: But ultimately you're releasing a certain amount of energy into the containment.

MR. LOBEL: Sure.

MEMBER BANERJEE: And there is an issue as to how that energy is being partitioned into the water or into raising the pressure. Ultimately, that energy goes into the -- mixes the noncondensables, raises the temperature, raises the pressure. Some of it goes into the water, raises this temperature.

MR. LOBEL: And it's -- response.

MEMBER BANERJEE: That is an outcome of this calculation. Right?

MR. LOBEL: Right.

MEMBER BANERJEE: And that number is 40 percent or something. Let's say -- Take it as 40 percent going into the water. Suppose it was 50 percent. What would happen there? That's the question I'm asking.

MR. LOBEL: Maybe they can answer the question but the point is that you're biasing this calculation very conservatively and so you don't have to answer the question of suppose the energy partition was different. You've --

MEMBER BANERJEE: You're biasing it within the bounds of the code calculation.

MR. LOBEL: You're biasing it within the input more than the code. Super-HEX as I understand, and GE can correct me again, is more of a best estimate code. You bias it by the input.

MEMBER BONACA: What code was used? Is this a licensed code?

MR. CROUCH: Yes.

MR. RAO: The effects we're talking about would be applicable for within the first ten minutes, not after that.

CHAIRMAN SHACK: Yes. I don't think we can review super-HEX here. Let's let him go on with their presentation.

MEMBER BANERJEE: All right. But --

MEMBER CORRADINI: Can I get to -- I think I know what Sanjoy is after. So let me ask it broadly and then you can think about it. I'm still struggling with the top red line and the bottom red line and you're saying that the difference there is primarily relative humidity. That is, one is 20 percent and one is 100 percent which means that the amount of noncondensables in the wetwell and then as I essentially do the blowdown and all the subsequent flow-through the wetwell condensation and blow back the noncondensables into the drywell that causes the difference in pressurization.

So I think where he's going with this is have you done a hand calculation, a site calculation, a confirmatory thing, to say that that is truly the dominant difference. It's not energy partition. It's not heat transfer coefficient. It's not all the things where I know he's going with.

MEMBER BONACA: No, I understand that.

MEMBER CORRADINI: It's a basically --

MEMBER BANERJEE: I can do a hand calculation I assure you which gives you very different results.

MEMBER BONACA: But what I would like to do if we could let them finish the portion on the LOCA because they're moving from curve to curve. I would like to know where they're going and then we can ask questions at that point if the answer is not there. At least we understand that. Then we move to get the scenario. So let's do that. Let's complete the LOCA portion.

MR. WOLCOTT: Add the next set of curves.

MEMBER BONACA: It will be interesting.

MR. WOLCOTT: We've added -- This slide adds curves that are focused on the core spray pumps by themselves. We'll show the RHR pumps separately. This adds two additional net causes of suction head curves for the core spray pumps. The green one in the center there is the same scenario for the core spray pumps, but it uses less restrictive input. So it's a bounding analysis using input assumptions that are less restrictive than the licensing basis one above it.

MEMBER BONACA: Which curve are you talking about here?

MR. WOLCOTT: The green one in the middle.

MEMBER BONACA: The green one in the middle which is right below atmospheric pressure.

MR. WOLCOTT: Yes. It's labeled CS realistic parameter.

MEMBER BONACA: Realistic parameter. Okay.

MEMBER CORRADINI: And can you explain a little bit more about what are those things that make it?

MR. WOLCOTT: Yes, the basis for choosing different parameters to do the middle curve there is we chose important plant input parameters and took them at their values that we don't exceed 95 percent of the time based on plant historical data. The licensing basis curve here would done taking all of those things at their tech spec limits which we never see. So we backed off a little bit for the middle line to the ones that we don't exceed 95 percent of the time just to use that as a basis for something that is a bounding analysis heading in the realistic direction.

MEMBER POWERS: I'm just curious. You chose 95 percent just because it was a nice number. Right? There was no reason for picking 95 percent.

MR. WOLCOTT: I felt comfortable with it. So that's what we chose.

MEMBER POWERS: It is roughly one out of 20 times that you'll be wrong or something like that?

MR. WOLCOTT: So as you can see that little line there, if I make those assumptions, then containment overpressure is barely required for a core spray pump a tiny bit for a very short period of time.

The lowest green line is that same analysis, but rather than to alter the input parameters, we did it without a single failure and that would be without a specific single failure affecting the RHR systems. So all the RHR system is running in the bottom line there and makes the results a little bit better. We have also generated a new red line for that event and it lays right on top of the other red lines.

MEMBER BONACA: So the single failure in this case was a loss of RHR train, right?

MR. WOLCOTT: That's correct.

MEMBER ABDEL-KHALIK: How can that realistic parameter red line be less than the bounding minimum value?

MR. WOLCOTT: Some of the realistic parameters move the containment pressure line down. Some of it move it up, for example.

MEMBER ABDEL-KHALIK: But presumably when you're coming up with the red line which you call the minimum containment pressure, you're biasing the analysis to give you the lowest possible red line.

MR. CROUCH: That just confirms that.

MEMBER ABDEL-KHALIK: It doesn't.

MR. WOLCOTT: That needs to be explained. It's important. The red line is determined by the pool temperature. There are really two big components that we need to talk about here. One of them is the vapor pressure coming from the pool water. When I back off on input assumptions for the green lines, I'm effectively lowering the pool temperature profile. So I'm lowering the profile of vapor pressure that is contributing to the red line.

Another assumption though we're changing to a more realistic assumption is how much noncondensable is present in the containment to begin with. That shifts the red line also. The licensing basis red line is done with 100 percent relative humidity which reduces the amount of initial noncondensable and drives this line to its minimum. But that's not realistic because we can't thermal dynamically.

We couldn't be within our tech spec limits on other things and still have 100 percent relative humidity in there. So the realistic relative humidity is 50 percent. So that shifts the line the other direction. So these two things offset each other and it's purely coincidence that the two lines fall on top of one another. So I've shifted the line up with one set of better assumptions and I've shifted the line down with another set. Those two offset one another and it just so happens that they lay on top of one another.

MR. RAO: This is Dilip Rao. Just by a point of clarification, I think you really want to look at the delta between the red line and the corresponding red line.

MR. WOLCOTT: Yes.

MR. RAO: And observe that the gap is increasing when you use realistic assumptions.

MEMBER ABDEL-KHALIK: No. Regardless of what happens at the pumps, I'm looking at one parameter, real parameter, which is containment pressure which we're modeling. Right? I'm not looking at a difference and I'm comparing the original thick red line which is labeled "Available Pressure Minimizes Containment Pressure" against the line that's pretty close to it which says "Available Pressure Realistic Parameters" and I'm asking why does the line that says "Minimizes Containment Pressure" exceed the line that says "Realistic Pressure" by a tiny amount.

MEMBER KRESS: It's because that first line that says "Minimizes Containment Pressure" is a misnomer. It minimizes it according to the prescribed calculational process that is prescribed. EPU is the process. It's the minimum in that process.

MR. WOLCOTT: I'm not sure -- I'm not sure I quite agree with that. Driving this entire thing is the heat up of the suppression pool. If I don't heat up the suppression pool, I don't have an MPSH problem and I also have a lot less containment pressure.

MEMBER ABDEL-KHALIK: We're not talking about MPSH. I'm just comparing the two red lines. Okay? I'm not talking about the differences.

CHAIRMAN SHACK: But his containment pressure depends on his vapor pressure and his suppression pool temperature.

MR. BOLGER: This is Fran Bolger from GE. In the derivation of the process, we developed the line that's called "Minimize Containment Pressure." You also have to consider various sort of input assumptions and how they impact the suppression pool. There may be assumptions that may yield a lower suppression pool temperature and that could also indeed lower this line called "Containment Minimum Pressure." Well, those type of assumptions are eliminated because the overall effect is an improvement. So when you develop this "Minimum Containment Pressure" it has to be looked at in combination with the impact of the suppression pool temperature.

MEMBER MAYNARD: I'd like to -- I think I understand Said's question here. To me it looks like any realistic pressure should fall between the minimum and the maximum and you have areas where the realistic parameters are falling below the minimum.

MR. WOLCOTT: Right. That's correct.

MEMBER MAYNARD: A pretty simple look at the graph there, I think.

MEMBER BANERJEE: Therefore, it's not a minimum. It cannot be defined as a --

MR. WOLCOTT: The minimum would be generated if I did not heat the pool at all, but that would not be meaningful to this analysis. I mean, if I didn't heat the pool at all, that's how I could generate the minimum. But, of course, if I didn't heat the pool at all, we wouldn't be here. In these things we are heating the pool and letting the pool heat as a driver to this.

MEMBER MAYNARD: I understand. I'm still not seeing why the minimum pressure is higher than the available pressure under realistic program though, the parameters.

MR. WOLCOTT: Do you mean what the physical explanation is?

MEMBER MAYNARD: Yes, just looking at the graph, I don't understand why the minimum isn't the minimum, why you have realistic analysis that shows less than the minimum.

MEMBER BANERJEE: It's not the minimum. It's the minimum under a certain set of assumptions.

That's all. I mean, that's what's been getting us confused right from the subcommittee. When you see minimum pressure, it assumes a whole lot of things in that minimum and when you see maximum pool temperature, you assume a whole lot of things in that maximum. So these are -- I think that are total misnomers.

MR. LOBEL: Maybe I could give an example that -- Let's pick one parameter, the heat exchanger effectiveness. If the heat exchanger was removing more heat, the suppression pool temperature would be lower and the water that's sprayed into the drywell and the wetwell would have a lower temperature. So I'm lowering the suppression pool temperature and I'm lowering the pressure.

But in order to do a conservative analysis in terms of MPSH, I want to keep the suppression pool temperature high. So in order to do that, I minimize the effectiveness of the heat exchanger. Now I'm spraying a little hotter water into the drywell and the wetwell. So I'm not minimizing the pressure but I'm giving the most conservative calculation that I can use for MPSH.

Everything is connected to everything else in this analysis and, like I say, sensitivity studies have shown that that suppression pool temperature is much more important than the pressure. So where there is a tradeoff like that, the analysis is done to give you a higher suppression pool temperature even though you may not have the minimum pressure anymore. I don't know if that helped.

CHAIRMAN SHACK: We're getting so far behind here. We're just going to have to let them move on to this presentation.

MEMBER BONACA: And then make a judgment.

CHAIRMAN SHACK: Make a judgment.

MEMBER BONACA: Apart from what we see. And particularly we really need to get to the Appendix R scenario too.

MR. WOLCOTT: The next slide here just adds the same information for RHR pumps since they don't need containment overpressure in the first place.

The conclusion that we draw from this sequence of slides and analyses is that we only need containment overpressure for the core spray pumps even in the licensing basis which is the least important set of -- And that if we use more realistic results, we don't need containment overpressure at all.

Now we get to Appendix R. We'll start out

--

MEMBER BONACA: Yes. Let me explain for this scenario. We all understand the LOCA, the assumptions you have to make, all this conservatism and we know how you are playing with parameters as inputs to go to realistic. For Appendix R, we don't understand that. We understand the scenario and one question that I'm going to ask at some point is is your minimum safe shutdown equipment just one RHR and two SLBs.

I mean, I would like to have answers to that question because the statement made to us was that it's a very conservative scenario. It's very low probability scenario. In reality, you have two RHRs. I'm trying to understand under what condition you would have these two RHR pumps and why this one RHR pump is just a very low probability scenario.

MR. WOLCOTT: The first slide here is the same thing we saw at subcommittee. So if there's no questions about that, I'll move on to the next sequence, the next thing on here. Here we've added the Appendix R containment pressure curve that you would see if you used maximizing assumptions rather than minimizing assumptions and the delta between those two red curves shows you how the results of the containment pressure would range as you range input assumptions. They are the same sorts of assumptions that we talked about when we talked about LOCA. The next curve.

We ran an Appendix R net positive suction head analysis with the same idea in mind of using less restrictive input parameters, again based on 95th percentile not exceeding.

MEMBER BONACA: So your RHR analysis was being done before the tech spec's values.

MR. WOLCOTT: No. In Appendix R, we chose values that if they are variable, we chose variables that we had never seen rather than tech spec values. They may have been one and the same, but we backed off from tech spec to values that we had never seen. This analysis backs off to numbers that we don't exceed 95 percent of the time. And as you can see, that lowers the amount of containment overpressure required and it increases the margin between the blue curve and the red curve that goes with it. It also makes a new red curve which is lower because the water temperature is lower for the same reason that we saw before.

MEMBER POWERS: I think it's an important point if I understand things correctly. When I look at this in isolation I say "Gosh, these guys are good.

They are confident that they can calculate within two psi. I can't do that." It doesn't really matter. If the pressure that you say minimizes containment pressure is off, so is your requirement. Is that correct?

MR. WOLCOTT: If it was due to pool temperature, yes.

MEMBER POWERS: It is.

MR. WOLCOTT: It would be off by approximately the same.

MEMBER POWERS: Yes, it would just shift up and down. So you really aren't claiming fantastic accuracy here. You're claiming that the delta is what's correct.

MR. WOLCOTT: Because these are bounding analysis which either drive things to the lowest or the highest depending on which we're interested in, they're not meant to be accurate. They're meant to make sure that they bound. So what would really happen would be somewhere in between these curves.

MEMBER BONACA: Now if I understand this, so the scenario is the limiting fire.

MR. WOLCOTT: Correct.

MEMBER BONACA: You're going to a safe shutdown feature here. In this case, you're abandoning control room. You are using your remote shutdown panel.

MR. WOLCOTT: That depends on where the fire is.

MEMBER BONACA: Depends on where the fire is.

MR. WOLCOTT: But some of these.

MEMBER BONACA: Yes. Some of them you can initiate from the control room. You're opening two SRVs. You're pumping with an RHR pump. You're bleeding. I mean, you're bleeding and fitting.

MR. WOLCOTT: Correct. We're in what we call alternate shutdown cooling which is injecting with an RHR pump, letting the water come out of the relief valves and return to --

MEMBER BONACA: Now a statement has been made that again this is a very low probability situation because you expect to have two RHR pumps available for this scenario. Could you expand on that?

MR. WOLCOTT: Yes. What our point is here is that the Appendix R scenario given the amount of detection, suppression, low fire loading, separation that we have in the plant, the probability of getting here with respect to having this much equipment degradation is very unlikely. This is coupled with an unrelated loss of offsite power which is kind of driven by the rule. If we get to keep offsite power and keep the main heat sync, we wouldn't be adding heat to the torus and we wouldn't be talking about this. So this is, you know, Appendix R lays out rules that's meant to drive us to analyze a severe loss of equipment. If all of these things didn't happen, then there are many angles at which you would not need containment overpressure either because you would be adding heat to the torus, but you would have more cooling of the torus or you wouldn't lose the balance of plant and you wouldn't be adding heat to the suppression pool to start with.

MEMBER BANERJEE: Let me ask you a question about does MPSH vary more or less linearly with vapor pressure.

MR. WOLCOTT: Yes.

MEMBER BANERJEE: Because ultimately, what you have in this system doesn't really matter as the containment pressure is determined by the vapor pressure plus the pressure exerted by the noncondensables, Dalton's Law more or less. And the MPSH, if it's varying with vapor pressure, then you have a situation where the two are in competition. So because of the noncondensables, you essentially, depends on the pump characteristics for MPSH, will always have some margin due to that.

MR. WOLCOTT: That's correct.

MEMBER BANERJEE: If you just do a hand calculation, that should come out.

MR. WOLCOTT: That's correct.

MEMBER BANERJEE: It just depends on how the MPSH varies with the vapor pressure.

MR. WOLCOTT: We get to keep our initial noncondensables.

MEMBER BANERJEE: Yes.

MR. WOLCOTT: The physics of the rest of the event of heating up the pool will guarantee net positive suction head. But I think what we're worried about here is the possibility of not being able to keep all those noncondensables.

MEMBER BANERJEE: It would be interesting to look at that curve. Maybe we have it.

CHAIRMAN SHACK: We can't be interested at the moment. We have to move forward.

MEMBER BANERJEE: Okay.

MR. WOLCOTT: So the purpose of this slide is to show which direction this thing goes as we back off on assumptions into getting more and more towards realistic and away from nonmechanistic assumptions. The amount that we backed up off here using the 95 percent parameters still shows us requiring containment overpressure for this event. But we have a three psi difference between that and the containment pressure we would expect to have at the pinch point where the curves are closest together. Next slide.

MEMBER ABDEL-KHALIK: Excuse me. This may be just the way this graph is drawn but could you explain to me why the difference between the two sets of graphs near the peak is larger for the blue lines than it is for the red lines?

MR. WOLCOTT: Try that one.

MR. EBERLEY: Why aren't they equal distance?

MEMBER ABDEL-KHALIK: Right. I mean if the main effect is a change in temperature.

PARTICIPANT: I think in the second case one of the more realistic assumption was an issue of time for the heat exchange.

PARTICIPANT: That wouldn't change that though.

MEMBER MAYNARD: You need to speak into the microphone there and identify yourself.

MR. EBERLEY: Bill Eberley with TVA. The two lines are slightly different, I think, because the initiation time for the RHR heat exchanger on the lower line is made a little bit earlier. We waited two hours to initiate the cooling on the --

MEMBER ABDEL-KHALIK: But the direct parameter that affects the change is temperature. Right?

MR. EBERLEY: Right.

MEMBER ABDEL-KHALIK: So whatever causes the temperature to change is really something that happened earlier. We're looking at why --

MR. EBERLEY: I think it gets to the discussion we had earlier where this is not one parameter effect being shown here. This is the effect of all these parameters together, the net effect of them, and I don't think there is an easy answer to that of why.

MR. WOLCOTT: I don't think we can figure it out on the fly without examining it a little bit.

MEMBER ABDEL-KHALIK: I think it would be -- For me at least, it takes away from the credibility of the result if there is no sort of physical explanation for something that we can see and the primary mechanism for changing the required net positive suction head is an change in the inlet temperature of the water. Right?

MR. EBERLEY: Right.

MEMBER ABDEL-KHALIK: And the question is what other parameters affect the red line that causes this to go down other than the temperature of the water.

MR. WOLCOTT: I think if we had a few minutes to think about it we could answer it.

MR. EBERLEY: Right.

MR. WOLCOTT: Perhaps maybe we could get back to you.

CHAIRMAN SHACK: Get back to you, but I think you're going to have to move forward.

(Several speaking at once.)

MR. WOLCOTT: All right. Moving to the next slide. Now we'll move away from bounding analysis and talk a little bit about the risk analysis we did. We made a PSA model change in LOCA, ATWA and station black events to apply probability distributions to the various parameters that drive containment overpressure. We did this following ACRS guidance that was given in the Vermont Yankee licensing.

We did probability distributions on those parameters I have up there which are river temperature, pool temperature, pool volume, and those are the important things that govern whether you need containment overpressure or you don't and the model would recognize based on the results of some deterministic analyses whether you needed containment overpressure or not in a particular situation and then could apply the probability of having a containment isolation failure which would take away the overpressure or having a pre-existing containment leak large enough to take away containment overpressure. From that we were able to measure for those events the risk of depending on containment overpressure for ECCS function as opposed to having no dependence recognized and that turned out to be a very small increase for those events of 2.4 X $10^{-8}$ per year $\Delta$CDF and $\Delta$LERF.

MEMBER BONACA: Appendix R?

MR. WOLCOTT: No, Appendix R is not modeled in our PSA model. So we were not able to make a quantitative measure on that.

MEMBER BONACA: Okay. So the numbers we received on the subcommittee, they were staff numbers. The staff did the calculation in fact.

MEMBER BANERJEE: Do you have any calculations for Appendix R for 105 percent?

MR. CROUCH: Calculations for?

MEMBER BANERJEE: Off these equivalent curves you were showing for 105 percent.

MR. WOLCOTT: Not like these. This level of analysis for special events really came into being when we began to license 120 percent. And in doing that, we reviewed ourselves against Revision 3 of Reg. Guide 1.82 and made a lot of changes to that way we did the analysis to come into compliance with that. So they wouldn't be very comparable because we uprated those.

MEMBER BANERJEE: But when you did Units 2 and 3 at 105 percent, what did you see with Appendix R calculations there? Do you require containment overpressure?

MR. WOLCOTT: Yes, it would have required containment overpressure. The figure of comparison that I do have is peak temperature. I'll give you some example. The peak temperature that you see in the analyses I'm showing you today is 223 degrees and it was about 213 degrees when done at 105. So you can kind of scale things with that.

But many other aspects of this analysis didn't come into being for special events until we went through the licensing of 120 percent. So a lot of the comparison at the level I'm showing you today there isn't one.

MEMBER BANERJEE: Do you recall how long you needed containment overpressure for?

MR. WOLCOTT: I sure don't because we didn't -- It's not laid out in time functions like this for the special events. In other words, the level of analysis is not nearly as much.

MEMBER CORRADINI: Just to repeat then, so then the 105 calculation analysis predates the special events concern that we're talking about here. That's what I heard you to say.

MR. WOLCOTT: Yes. To the level of detail we do here today.

MEMBER CORRADINI: Thank you.

MEMBER BONACA: Okay.

MR. WOLCOTT: Any other questions about that? In summary then, our licensing basis analyses that we use for MPSH are conservative, that our overpressure credit is in line with the industry, that we have if you do more realistic analyses we show that COP dependency is reduced or we don't need any at all and that there's a very low risk of dependency on containment overpressure when done following ACRS guidance.

MEMBER APOSTOLAKIS: That fourth bullet is very interesting. I read it differently. Does anyone else read it differently? "Very low risk following ACRS guidance." Okay?

(Laughter.)

MEMBER BONACA: George, you shouldn't have.

MR. WOLCOTT: That concludes our presentation.

MEMBER APOSTOLAKIS: It took a few seconds.

(Laughter.)

CHAIRMAN SHACK: Let's move on.

(Off the record comments.)

MR. LOBEL: Are we ready? Good morning. My name is Richard Lobel. I'm a Senior Reactor Systems Engineer in the Containment and Ventilation Branch and I'm here to talk about containment accident pressure. Actually, in my slides, there's a slide to talk about the other aspects of the containment review, but let me just say as a summary that there really were no issues in the other parts of the containment review for 105 percent that all the criteria were followed and all the temperatures were within margin.

Rather than go through my slides, I thought I'd just make a couple comments and leave time for questions if that's okay.

MEMBER BONACA: Yes.

MR. LOBEL: The main issues that were raised in the review of containment accident pressure, there were really three areas that had the majority of the questions and the majority of the review time and one was cavitation of the RHR pumps for the short-term LOCA. The Licensee didn't talk about the short-term LOCA because I'd been doing that for the subcommittee.

But for the short-term LOCA even crediting containment accident pressure and some pump vendor reduced required MPSH values, the RHR pumps were predicted to cavitate for approximately four minutes and we spent considerable time and the Licensee spent a lot of time and effort justifying that in terms of conservatisms in the analysis, the tests that had been run by TVA back in 1976 for basically the same purpose and an evaluation by the pump vendor, the maker of these pumps. We asked TVA to go back to the pump vendor and get an assessment from the pump vendor and they came back, the pump vendor came back, and said that the pumps would survive the cavitation for the short time and still perform their safety function.

MEMBER BANERJEE: This was for design basis LOCA.

MR. LOBEL: Yes. Part of the conservative argument was that if you didn't use design basis conservative assumptions, that containment accident pressure would still be necessary using the reduced required MPSH curves, but that the pump wouldn't cavitate. The pumps wouldn't cavitate. So you still needed credit for containment accident pressure. This is for the short-term LOCA, just for that one event.

MEMBER BANERJEE: Okay.

MR. LOBEL: And short-term, the way the MPSH analyses are done, there is a short term which is the first ten minutes when you assume there's no operator action. So the pump flows are essentially determined by the system and relatively high and then after ten minutes, operator action is allowed and the operator throttles back the pump flow.

And in talking to some senior reactor operators and STAs at Vermont Yankee and in answer to a question from Browns Ferry, both verified that ten minutes is a pretty long time for the operator to throttle back the pumps. Typically, it could be done in a couple minutes after the start of the accident.

MEMBER BANERJEE: Does this also, the same sort of scenario, curve for any of the other accidents, ATWS, any special events, Appendix R?

MR. LOBEL: No.

MEMBER BANERJEE: Only for the large --

MR. LOBEL: Only for this event because you have the RHR pumps pumping into the broken loop which are essentially pumping against containment accident pressure and so there are very close to run-out flow. They would be at run-out flow if it wasn't for orifice plates that are in the piping, orifice that are in the piping. So it's just for the short-term one. The operator isn't reducing the flow and you're essentially at run-out flow.

So it's not so much suppression pool temperature and pressure that are the problems for the short-term LOCA. It's the high pump flow which gives you a very high required MPSH.

MEMBER BANERJEE: I remember I had a question about in this situation whether you could get vortexing and some behavior like that right when you pull through the strainer.

MR. LOBEL: I thought the Licensee answered that question last time.

MEMBER BANERJEE: Right, but then we had an issue with approach velocity they used if you recall. Was that satisfactorily resolved?

MR. EBERLEY: Bill Eberley with TVA. Could you repeat the question please?

MEMBER BANERJEE: I think the issue arose under these conditions when these pumps are running pretty flat out whether you would get some vortexing and suck-down to the strainers because they are all pulling through strainers still. Right?

MR. EBERLEY: Right.

MEMBER BANERJEE: And I had an answer based on Froud number, but then I suggested that the approach velocity would not be the approach velocity based on the area of the strainers but simply on the projection of that onto the surface so that you would get -- In any case, I wonder whether this issue has been addressed since that time.

MR. EBERLEY: In answer to your question, yes, we did go back and take your question a little more seriously and have time to calculate the Froud number using different flow areas or different areas, projected areas. In one case using the hydraulic area of the outside of the strainer, we get a Froud number of 0.07 and approach velocity there would be 0.8 feet per second.

If we treat it as a bottom, open pipe exit just using the pipe cross section, I don't have the Froud number that we got from that, but we would require a submergence of six feet for that open pipe suction and ours is 8.4 feet submerged. So in any case, we don't expect any vortexing to be supported.

MEMBER BANERJEE: You have about eight feet. Right?

MR. EBERLEY: Yes. To the 29 inch pipe that's attached to the bottom of the strainer. Plus these strainers are very good vortex suppressors as far as they have veins inside them.

MEMBER BANERJEE: I'm talking about more what will come to the strainer from the surface.

MR. EBERLEY: Right.

MEMBER BANERJEE: Okay.

MEMBER ABDEL-KHALIK: But wouldn't vortexing of six foot reduce the available MPSH by more than 2 psi?

MR. EBERLEY: If you could pull air into the suction and break suction, that would be a challenge. But we don't have the flow rates through the strainers to support a continuous vortex. We don't expect to see a vortex.

MR. SIEBER: You have to pull the air through the strainer.

MR. EBERLEY: Yes.

MR. LOBEL: Also keep in mind that these pumps now for the short-term LOCA, all they have to do is survive. They have no safety function for the short-term LOCA.

MR. EBERLEY: Right.

MR. LOBEL: There are two trains of RHR pumps. One train is cavitating. The other train is not cavitating and it's the train that's supplying injection to the core for the short term. So the reason we have this concern with cavitation is that when we go to the long term after the operator has reduced the flow, we can take a single failure of the train that was injecting into the core and now this train that was cavitating has to perform the safety function of suppression pool cooling. But in the short term, it has not safety function. That train has no safety function.

MR. EBERLEY: I would add one thing to what Rich said and I agree that the numbers that I quoted were based on the short-term, high flow rates where our worst strainer is taking 15,000 or thereabouts gallons per minutes flow which gets reduced to about 5,000 gallons per minute in the longer term.

MEMBER BANERJEE: The situation is the worse when everything is working here.

(Laughter.)

MEMBER BANERJEE: Right. It gets sucked down this.

MR. LOBEL: Okay. The other two things that we spent most of our review time on was the behavior of the drywell fan coolers since for Browns Ferry the fan coolers are assumed to continue to operate for some events and we questioned the pump flows that the Licensee had assumed. There were a few questions and answers clarifying that and some revised calculations. So those were the three areas, cavitation of the RHR pumps in the short term, use of the drywell fan coolers and the pump flows that were used.

MR. SIEBER: Are the motors on the fan coolers sized to take the -- to operate under the increased pressure?

MR. LOBEL: They're not assumed to operate for the LOCA. No.

MR. SIEBER: Okay.

MR. LOBEL: Because just the atmospheric conditions, the energy that you're putting into the drywell --

MR. SIEBER: You'd burn out the motors or they would trip. They would trip.

MR. LOBEL: And it doesn't matter for the LOCA.

MR. SIEBER: Right.

MR. LOBEL: The other two things I mentioned is we looked at the impact on the operator and concluded that there was no impact on the operator. The operating procedures already cover guidance for detecting cavitation and response to cavitation and for all these accidents, the design basis and the special events, part of the guidance is to assume containment integrity. The accidents analysis is done assuming containment integrity and that's based on all the tests and procedures, start-up procedures, and procedures for verifying valve position and that kind of thing, Appendix J leak testing, 50.55(a), containment inspections that are done to verify containment integrity prior to an event. That's a fast summary of what I was going to say.

MS. BROWN: All right. At this time, we're going to have Mr. Jim Dyer, the Office Director.

MEMBER BANERJEE: Do you need this credit for Appendix R or -- I'm sorry. The LOCA in the short term at 105?

MR. LOBEL: Yes. I haven't seen any 105 calculations. But based on the calculations for Units 2 and 3 even though there had been a few changes that have been made and assumptions and things, I'd say yes. You still need containment.

MEMBER BANERJEE: But for a briefer period?

MR. LOBEL: Well --

MEMBER BANERJEE: But it wouldn't cavitate at 105. Is that it?

MR. LOBEL: It probably -- Yes, it wouldn't cavitate at 105.

MEMBER BANERJEE: It wouldn't cavitate beneath the pressure?

MR. LOBEL: I'm looking at --

MS. BROWN: Licensee.

MR. LOBEL: -- man from GE there. She ought the question.

MR. RAO: Dilip Rao from GE. In the first ten minutes, what drives the containment response is the inventory in the vessel, not really the metal internals and inventory in the vessel. It's the energy. Even the decay heat is not that significant in the first ten minutes. It's over the long term that you see the cumulative effects of decay heat.

MEMBER BANERJEE: So nothing would change in the first ten minutes.

MR. RAO: If you set the same containment pressure and the same enthalpy, no. Nothing will change and I think this is a constant pressure for both 105 and 120. So really the thermal dynamic conditions in the vessels are the same for both.

MEMBER ABDEL-KHALIK: Let me just follow up on a question I asked earlier. Does the calculation for the available net positive suction head take into account the change in hydrostatic head above the suction point due to vortexing?

MR. EBERLEY: The answer to that is no. There is no vortexing and therefore there is no change in the elevation due to vortexing.

MEMBER ABDEL-KHALIK: The change in the elevation of the free surface?

MR. EBERLEY: We don't --

MEMBER ABDEL-KHALIK: The hydrostatic head.

MR. EBERLEY: We don't reflect that in the MPSH analysis because we don't expect that there is a significant change in the free surface.

MEMBER ABDEL-KHALIK: But you just said

that it's six feet.

MR. EBERLEY: No, I said that we have submergence of 4.3 feet to the top of the strainer and if we were to treat it as an open pipe suction as opposed to suction with the strainer on it, the elevation of the open pipe would need to be at least six feet submerged. It depends on the flow velocity. If you're only treating the small area of the pipe the velocity is much higher than if you're treating a strainer with a larger area.

MEMBER ABDEL-KHALIK: Regardless of what the depth of the vortex is.

MR. EBERLEY: There is no vortex. There is no vortex. That's the answer.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. LOBEL: The level of the water does change during the accident and that's included in the calculation of MPSH.

MEMBER ABDEL-KHALIK: I understand, but --

MEMBER CORRADINI: So can I ask a general question?

CHAIRMAN SHACK: No, we're going to move on.

MEMBER BONACA: Yes, we have to stop it.

MR. SIEBER: Jim.

MS. DYER: Thank you, Mr. Chairman. I wanted to come down here for the closing remarks and it started off the same way I did to Chairman Bonaca when he was at the subcommittee meeting and thank the ACRS for accelerating their schedule and the review of the safety evaluation for the Browns Ferry Unit 1 105 percent uprate in that at the time we originally set the schedule, we anticipated the restart sometime in February, possibly could be in February, based on the Licensee's workload and between the subcommittee meeting and this full committee meeting, we had a Commission meeting and TVA had adjusted their restart schedule now for some time later this spring and for other business reasons and coordination with other outages and that. I actually took a deep sigh of relief when that happened because from a safety perspective I think it's good to get the licensing issues done in time to let them soak and let the Licensee reflect on the final safety evaluation.

With that, I still thank the Committee for their prompt review of this issue. I learned a lot from the subcommittee debrief and what I learned is there's a lot of things to do for 120 percent power and this is kind of a unique being 105 power but having many of the attributes, many evaluations, for the 120 percent extended power uprate which was the original Browns Ferry Unit 1 request that was subsequently delayed when the staff was having challenges coming to a conclusion on some key issues which are a lot of the same key issues that the Committee is reviewing.

With that, I would also note that these are issues that I think need to be dealt with industry wide and through the Owner's Group or all the vendors anticipating coming in, I mean, the utilities anticipating coming in for extended power uprates and we do have the three Browns Ferry units with anticipated extended power uprates as well as Hope Creek and Susquehanna in-house right now doing the reviews and we're struggling with the same challenges that had been discussed at length here. So thank you very much for your support.

MR. SIEBER: You're welcome.

CHAIRMAN SHACK: Thank you.

MEMBER BONACA: Okay.

MS. BROWN: That concludes our presentation. Thank you.

MEMBER BONACA: Concludes it. Through.

CHAIRMAN SHACK: Okay. We're going to recess now. I remind the Committee we have interviews which are already delayed. So promptly get whatever you're going to eat for lunch and come back up for the interviews. We want to start up again in an hour.

MEMBER APOSTOLAKIS: What time are the interviews? Right away?

(Off the record comments.)

CHAIRMAN SHACK: Immediately. We'll start the next session at 1:15 p.m. because again it's a noncontroversial one that we ought to get through quickly without much trouble. Off the record.

(Whereupon, at 12:14 p.m., the above-entitled matter recessed to reconvene at 1:18 p.m. the same day.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

1:18 p.m.

CHAIRMAN SHACK: On the record. I'd like to come back into session now. We're going to be discussing the final review of the license renewal application for Oyster Creek Generating Station and Otto Maynard will lead us through that. Thank you.

MEMBER MAYNARD: Thank you, Mr. Chairman. As many of you know, we've had two subcommittee meetings on this subject, one in fact last October. The other was January of this year. During those meetings, a number of questions have been asked, raised, answered, developed. We've had the benefit of looking at a lot of data. A lot of information has been provided to the ACRS members to review. Some of that has answered questions. Some of it generates questions and that's the purpose of this meeting.

We've also received input from the public and we've received some letters from the Congressional representatives from New Jersey. We've also received a letter, actually I think the Commissioners did, from the governor inviting us if we needed to to come to Oyster Creek for a meeting there and discuss information further. So getting a lot of interest.

We also have some people on the telephone listening today. We need to make sure that everybody does speak up so the people on the phone can hear us. We'll do our best to keep that going.

The presentation today, we're going to be going over some of the material in the beginning just to bring everybody up to speed and I would caution the members. If there's something from clarity from the beginning of that on the history, that's fine. But we're going to be getting a number of the specific details of certain issues after the Licensee, the Applicant, has gone through some of those. So we'll keep an eye on that so we don't spend too much time on history that's already been gone over in some of the various meetings there.

After all of our discussion, there are two key areas that have still generated a lot of questions and interest. One is the continued leakage that is seen for refueling outage and stuff, although it's put in the drain capacity, I think there's still some interest in discussing that. The other gets into the analysis done for the containment shell, the drywell shell and the use of certain code cases, the applicability of that, and I understand we're going to have some good discussion on that as well as some other things. So there is a number of key issues that are going to be addressed.

With that, I'd like to turn it over to Bob Schaff of the staff just to get us started with the staff and then I think turn it over to the Applicant.

MR. SCHAFF: Thank you, Mr. Maynard. My name is Bob Schaff. I'm the Acting Branch Chief for License Renewal Branch A in the Division of License Renewal. To my left is Pat Hiland who is the Director of NRR Division of Engineering. To his left is Louise Lund who is Acting Deputy Director for the Division of License Renewal. To my right is Donnie Ashley. He is the Project Manager for the review of AmerGen's application for the renewal of the Oyster Creek operating license. We also have a number of members of NRR's Technical Staff in the audience who are available to provide additional information and answer any questions that the Committee may have today.

As Mr. Maynard noted, several questions regarding the Oyster Creek drywell shell remain the following last license renewal subcommittee meeting held last month. Today's meeting will allow the Applicant and the NRC staff an opportunity to respond to those questions as part of their presentations.

With that, I'd like to turn the meeting over to Mike Gallagher, Vice President of Exelon's license renewal group to begin the Applicant's presentation.

MR. GALLAGHER: Okay. Thank you, Bob. Good afternoon. My name is Mike Gallagher and I'm the Vice President of License Renewal Projects for AmerGen and Exelon. Also with me here today from our senior management team is Rich Lopriore, our Senior Vice President of MidAtlantic Operations and Mirshak Rame, our Senior Vice President for Engineering and Technical Services.

On January 18th, we presented to the subcommittee the details and basis for our overall conclusions on the Oyster Creek drywell corrosion issue and just to recap, our overall conclusions are the corrective actions to mitigate drywell shell corrosion have been effective; drywell shell corrosion has been arrested in the sand bed region and continues to be very low in the upper drywell elevations; and the service life of the drywell shell extends beyond 20.29 with margin. The corrosion on the embedded portion of the drywell shell is not significant due to the environment of embedded steel and concrete. The drywell shell meets code safety margins and we have an effective aging management program in place to ensure continued safe operation of Oyster Creek.

For today's presentation, we will provide a summary of the drywell shell corrosion issue. Can we go to the agenda? However, we can go into any level of detail that you desire.

We also will have discussed five issues that the subcommittee had from our last meeting and our proposed resolution and you mentioned two specifically, Mr. Maynard. We have those covered. We will also provide an overall summary of our license renewal application at the end of the meeting.

Our handouts today are we have the presentation. We have the reference material booklet which is the same reference material booklet we provided last time. It has the pictures and the detailed graphs of the entire drywell and we also are providing to you today this table which is a summary of all our drywell inspections and that's one of the five issues we want to talk to you about later in our presentation.

Also this week, I did send in a letter, Subcommittee Chair Maynard, with AmerGen's response to issues presented to the subcommittee during the public comments session of the subcommittee meeting just for your consideration.

Presenting for AmerGen today will be Fred

Polaski, John O'Rourke and Ahmed Ouaou from our License Renewal group. We also have with us here today Dr. Hardiyal Mehta from General Electric for our presentation on the capacity reduction factor which is in our buckling analysis and we also have Dr. Clarence Miller, the author of Code case N-284 which relates to the capacity reduction factor. And both Dr. Mehta and Dr. Miller will be making a presentation later on in our presentation.

I'll now turn the presentation over to Fred Polaski who will go through some background and then the drywell corrosion issue.

MEMBER MAYNARD: Before you, since you brought up your letter, I need to mention that at the beginning of the full Committee meeting this morning we acknowledged letters that we had received. But some of the people may not have been in the room at the time and in addition to your letter, we also received a letter from Mr. Webster and others mentioned earlier from Congressmen and the Governor. So there is other correspondence and I believe Mr. Webster also is going to be making comments at the end of the meeting today. So just to put that on the record, although it was stated this morning also.

Go ahead, Mr. Polaski.

MR. POLASKI: Thank you. My name is Fred Polaski. I'm Exelon's Manager for License Renewal. I would like to begin today with an overview of --

(Off the record discussion.)

MR. POLASKI: I would like to begin with an overview of the physical layout of the drywell to provide the background on the presentation in drywell corrosion. This slides shows a cross section of the Oyster Creek reactor building. The reactor vessel is shown in green in the middle. The recirculation piping and pumps are also shown in green. The drywell is shown in red. Outside the drywell is the concrete shielding which forms part of the reactor building.

The drywell connects to the torus through these ten vent headers which are depicted here in green. This picture is shown in the refueling condition. At operation, the reactor head would be installed up here and the reactor cavity and also the drywell head. This is shown with the heads removed and the reactor cavity is shown in blue with cross-hatch to indicate it's full of water in the refueling condition.

Inside the drywell, the orange depicts the concrete floor in the bottom of the drywell and this also depicts the reactor pedestal. The red band here indicates the sand bed region or the external surface which goes circumferentially around the entire drywell.

In our next three slides, I'm going to show you details of the reactor cavity liner, the refueling bellow seal area and then the sand bed where it will show how water leakage from the reactor cavity would leak through this liner and get to the sand bed region. This occurred prior to corrective actions that were taken in 1992 to address the leakage issue. Next slide please.

This is a detail of the reactor cavity liner. The pink indicates the 1/8th inch stainless steel plates that form the reactor cavity liner. They were welded together in the field. There are numerous small cracks in that liner which allowed water to leak through the liner and then the leakage is indicated here in the dark blue where the leakage comes through the liner and then will run down inside of the concrete wall down into this area down here. We'll go to the next slide which will show the details of this.

This is a detail of the bellow seal area. Depicted here in purple is the refueling bellows. There has been testing performed at Oyster Creek to determine that this bellows does not leak. Also part of the design of the plant below the bellows is a concrete leakage collection trough which is built into the concrete structure to collect any leakage coming from the bellows or any other sources and would route it through this one single drain line out of this collection trough which is only two inch diameter to the rad waste system.

CHAIRMAN SHACK: And that's just one drain, the whole 360.

MR. POLASKI: That is correct. There's only one drain line for the trough and later when we get to the sand bed I'll show you that there's five drains out of the sand bed region but there's only one here and it's only two inches in diameter.

The other things to note here, this is the drywell shell. Depicted here is the gap between the drywell shell and the concrete. The red shows firebar D insulation. It was installed on the outside of the drywell during construction. That was compressed to form a one inch gap between the concrete and the firebar D.

This is the leakage path that gets the water down to the sand bed. So if I trace the leakage path, pick it up here at (2) behind the liner, underneath the stainless steel plate and behind this plate, and then (3), it will come out from behind the liner into the trough. The design is such that the leakage should go down this drain line. But what happened was there was damage here indicated at (4) to the lip of this trough which allowed water to overflow into the gap.

After the repairs were made to this in 1988, they still continued to have problems with water getting into the gap because the volume of leakage coming from the liner exceeded the capacity of this drain line and so we still continued to overflow. In 1990, the plant began to install -- Actually, in 1990, for the first time, they installed metallic tape and strippable coating on the reactor cavity liner which greatly reduced the leakage to within the capacity of this trough and drain line to prevent the water from getting into the gap and then reaching the sand bed region. Next slide please.

This is the sand bed region and the water leakage. We'll pick it up here at (5). Depicted in blue. Comes out of the gap. It either goes, you know, comes out between the vent headers or around the vent headers into the sand bed region here. Now this is shown with the sand removed and you can see the diameters of that.

Below the sand bed, the drywell shell is embedded on concrete on the inside and the outside. The sand bed region provides a transition from the embedded section of the shell to above where it's a free-standing pressure vessel. The green cross-hatch here are the drywell vents that I showed you before.

I would also like to point out inside the drywell the red cross-hatch is the floor inside the drywell and then this shows there are two different -- There's a curb on the inside here at two different elevations. The lower curb is depicted here in red and then the upper section in blue cross-hatch and I've have a three-dimensional model that shows that a little bit better. The other thing to point out is there are one of the five drain lines out of the sand bed region.

So at this point, I would like to go to the 3-D model. And after I'm done showing you this, we'll pass it around and you can look at it in more detail. What this depicts is it's a 90 degree section of the lower part to the drywell. This gray out here and below it, this is the concrete shielding around the drywell. Down below is the mat for the drywell. The black depicts the liner, the carbon steel liner or actually the shell.

Because of the modeling limitations, we can't show the gap, the one inch gap, on the outside of that, but there's a gap between the shell and the concrete. The green here are the vent headers. It's the same as on the other ones that come out on the outside and get into torus.

Inside the drywell, we have the concrete floor. This is the reactor pedestal for the reactor. It would sit above that. Inside of this is what we call the sub-pile room and later in our presentation today we're going to talk about the water leakage in here and some issues with water on the inside of the shell and at that time we will mention the sump, the drywell collection sump, and also the leakage collected in the trough which is around the inside of the sub-pile room.

The region of most interest of course is the sand bed region which is shown here on one end and over on the other end. I would point out too that I mentioned the two different elevations of the curb. Inside here the curb is about nine inches higher than the four underneath these vent headers and then in between it gets higher and the top elevation of this, the 12 foot three inches corresponds to the level of the sand that was in the sand bed region before it was removed. So the sand would fill up almost the entire volume of the sand bed region. There was an air space at the top with the level corresponding to the top of this curb and you can see that when we get into -- We can take reading from the inside.

There are five drain lines out of the sand bed region. This depicts one of them in the core section and on the outside you can see another one over here. The only thing I'll point out is these larger holes are the 20 inch diameter personnel access holes that were drilled or pried into the concrete to gain access to the sand bed. So there's ten of these, one to each of the bays that we use for access during inspections.

Any questions on the model or anything on the physical configuration? We'll pass this around if you'd like to take a look at it.

(Off the record comments.)

MR. POLASKI: I would now like to introduce Mr. John O'Rourke who will present a summary of the corrosion of the drywell shell. This will be a brief summary of the cause and corrective actions, the analysis that was performed to determine the minimum required thickness of the shell, the removal of the sand and application of epoxy coating in 1992 and the current condition of the shell, specifically results of inspections during the refueling outage in October 2006. Mr. O'Rourke.

MR. O'ROURKE: Thanks, Fred. Now that Fred has truly traced the leakage baths in the reactor cavity liner down to the sand bed region, I'll summarize the important points regarding the Oyster Creek exterior drywell corrosion.

First, as Fred demonstrated, leakage from the reactor cavity liner accumulated in the sand bed region and corroded the exterior surface of the drywell shell. Corrective actions have been taken and have been demonstrated effective in arresting corrosion in the sand bed region. These corrective actions completed in 1992 include preventing water from entering the sand bed region, removing the sand, cleaning the drywell shell and coating the exterior shell with an epoxy coating and performing analysis to determine the Code required thickness of the shell.

At this point, I will provide a brief summary of the analysis performed on the drywell. We will discuss the capacity reduction factor and buckling in more detail in the next part of the presentation. General Electric performed the analysis of the Code required thickness in 1992. A buckling analysis based on Code Case N-284 for the refueling condition with no sand in the sand bed region and a Code safety factor of two resulted in 736 mils being the Code required thickness for buckling in the sand bed region. Additional sensitivity analysis performed by GE established a local required thickness criteria of 536 mils for a 12 X 12 inch area.

GE also performed a Section 8 analysis for the internal pressure based on the original design pressure of 62 psig which was later revised to 44 psig which is the Oyster Creek plant-specific maximum design pressure. The use of the 44 psig was approved in 1993 via tech spec Amendment. This analysis demonstrated increased margin for the minimum required thickness versus the original analysis at 62 psig.

The results of our monitoring performed during the October/November 2006 refueling outage are as follows. There was low leakage for the reactor cavity liner of approximately one gallon per minute and it was controlled by the reactor cavity leakage trough. There was no water in the sand bed region. This was monitored on a daily basis while the cavity was filled either through direct physical inspection of the bays or by monitoring the sand bed region drains. The epoxy coating was 100 percent visibly inspected in all the bays and found to be in good condition and I will shortly show you pictures of the coating.

The ultrasonic grid measurements in the sand bed region from the inside of the drywell indicated no corrosion. The local ultrasonic measurements in the sand bed region from outside demonstrated that the drywell shell exceeds designed thickness requirements. The ultrasonic grid measurements taken in the upper drywell elevations indicate no corrosion except at one location which shows a very low corrosion rate of less than one mil per year.

The next several slides will show you the pictures of the external drywell shell. This first picture taken in 1992 after the sand was removed shows the condition of the exterior shell prior to preparing the surface for coating. The loose rust would have been removed with the sand, but you can still see some rust still adhering to the shell which was easily removed during the surface preparation activities.

This picture also taken in 1992 shows the external shell after cleaning and application of the epoxy coating. It also shows the cloth seal between the drywell shell and the sand bed region floor. And this picture taken during the October/November 2006 refueling outage shows the epoxy coating and caulk seal condition observed during that outage. As you can see the coating continues to remain in very good condition. This picture is also representative of all the bays and in the reference books that we provided to you, there are more pictures of the external drywell shell.

This slide shows a pictorial representation of the location of the ultrasonic measurements taken during the October/November 2006 refueling outage in the sand bed region. But since this slide is hard to see, if you refer to the last tab in your reference books, you'll have a bigger picture of this slide if you want to refer to that.

Both are the extensive coverage of the shell in the sand bed region with increased monitoring points in the areas determined to be the thinness. The triangles are the individual points taken from outside the drywell. The squares are the seven point grids taken from inside the drywell. The rectangles are the 49 point grids also taken from inside the drywell and the small yellow squares within the rectangles are individual points within the 49 point grids that are less than 736 mils thickness. The long rectangles represent the points monitored in the trenches in Bays 5 and 17.

The green color indicates readings that are above 736 mils which is the minimum required general thickness I noted earlier. Note that all the average grid readings exceed this value. Also all the white area denotes shell thickness that is greater than 736 mils. The yellow indicates readings between 636 and 736 mils and we have one read individual measurement indicating a reading between 536 and 636 mils with the 536 mils being the minimum-required thickness for a localized area no greater than 12 X 12 inches. When we identified this point, we interrogated the area around it to confirm that we had identified the thinness point for future monitoring.

This representation demonstrates that all the areas we're monitoring in the sand bed region exceed the minimum required thickness requirements for either the average or local measurement.

CHAIRMAN SHACK: That big white area that I see there, am I to assume that that's really practically the original thickness? There's no sign of attack or it's just it wasn't thin enough to warrant measurements?

MR. O'ROURKE: It was not the thinness

area that we are continuing to monitoring on an on-going basis and it is above 736 mils.

CHAIRMAN SHACK: But I mean I see no measurements there in that whole white region.

MR. O'ROURKE: There's no on-going measurements in that region. We had interrogated the region --

MR. GALLAGHER: He's talking -- Dr. Shack, are you talking just the general what ifs?

CHAIRMAN SHACK: Yes, that big white area.

MR. GALLAGHER: We're just trying to say simply when we went into the sand bed and looked externally, those individual triangle points, they were the thinness locations after we looked at 100 percent of the sand bed. So in general, the white area is much thicker than 736 and that's what we're saying.

MEMBER MAYNARD: And these are the areas that with the sand removed you can physically see the condition, the outside of that.

MR. GALLAGHER: That's correct.

CHAIRMAN SHACK: But if I'm going to do my full three-dimensional mapping of the degradation, I can't assume that that white region then is 1.154. It's degraded some dimension I don't know.

MR. O'ROURKE: That's correct.

MR. GALLAGHER: Yes, and one thing you could use in an analysis like that is the general thickness in each bay and, you know, as measured by our grids because those are the thinnest areas in each bay and then if you look at, actually it's the next page, page 15 where it shows you additional margin in each bay, you could input those numbers and apply it to the -- I would probably say an average thickness in that bay, and it would show you that there's more margin because of more metal in those other bays.

MR. O'ROURKE: And those numbers were established by interrogating from inside the drywell about 500 points around in the sand bed region to determine where the smallest margin was.

MEMBER ABDEL-KHALIK: If we go back to slide 14, those clusters of yellow squares, they are sort of too close to each other. Would one -- Can one assume? I mean you have in some areas seven of those yellow squares and each one is presumably six inches by six inches. Can one assume since they are so close to each other that there may be a contiguous area that has a thickness between 636 and 736 that is larger than a square foot?

MR. GALLAGHER: No. Those individual

yellow boxes, yellow squares, they are individual points within the 49 point grid. So the six by six grid that we take from the inside which is depicted by those long rectangles, what we're just trying to show is when measuring those 49 points some of them are less than 736 and they're included in the average for that particular grid. So to say if you look specifically, Fred, if you could point to one of those, just the one all the way on the end, so that's one grid with 49 points and there would be five individual points that are less than 736 but greater than 636. We have the actual numbers and there were included in the thickness calculation for that.

MEMBER ABDEL-KHALIK: Those are individual data points then.

MR. GALLAGHER: They are individual data points.

MR. O'ROURKE: They're five out of the 49 in that particular case.

MEMBER ABDEL-KHALIK: Thank you.

MR. O'ROURKE: Slide 15. This slide summarizes the monitoring performed in the sand bed region from inside the drywell and the minimum available margins in each of the ten bays based on the lowest average reading in each bay. This data indicates measurements taken in 2006. However, these margins are based on the lowest average readings regardless of the year it was measured.

On the next slide I'll show you the trend graph for bay 19 which has the smallest margin and which is the bounding margin. But as you can see, we have up to 439 mils of margin in some of the other bays which is essentially nominal wall thickness.

This slide graphically represents the ultrasonic measurement data for one of the monitored locations in the sand bed region and all of the graphs are in your reference books. However, we selected two representative samples to include in this presentation and this is the location with the least amount of margin shown on the previous slide, bay 19. Note the lines representing the nominal wall thickness and the required wall thickness.

Prior to removal of the sand from the sand bed regions in 1992, this location exhibited a wall loss of 15 mils per year. Since 1992, the curve has been flat indicating there has been no additional wall loss. The numbers above the curve from 1992 to 2006 are the standard errors for the data and not the corrosion rates and this slide demonstrates how we track and trend the data from inside the drywell.

Slide 17 is another example of one of the monitored locations in the sand bed region. This particular location shows close to nominal wall thickness and no corrosion since monitoring was started in 1988 and as I said, the remainder of those graphs are in your booklets behind Tab No. 3.

Slide 18 summarizes all the areas of the drywell and the minimum available margins based on the minimum measured average thicknesses at the various locations including the sand bed data I just discussed. Again, note the additional margins available in the areas above the sand bed region.

To summarize the commitments we've made that are part of our aging management program for the drywell, we will continue --

CHAIRMAN SHACK: Just a quick -- The minimum thicknesses required above the drywell are based on pressure loads for the thinnest section. The minimum load in the sand bed is the buckling load and that's the margin for buckling.

MR. O'ROURKE: That is correct.

MEMBER ARMIJO: Just to clarify. Now that buckling load is limiting in all cases or just in the case of refueling?

MR. O'ROURKE: In the refueling case.

MR. GALLAGHER: The refueling case is the limiting load combination.

MEMBER ARMIJO: If you weren't in the refueling condition, would that buckling issue still be limiting?

MR. GALLAGHER: Yes. We did all the load combinations and so one of them is the accident load combination. So it would just say that the thickness requirement would be higher, excuse me, lower so that there's more margin.

MEMBER ARMIJO: You would have margin in a non-buckling load in a nonrefueling situation.

MR. GALLAGHER: That's correct.

MEMBER ARMIJO: Margin against buckling and how much would that margin be?

MR. GALLAGHER: Maybe we could ask -- Ahmed, do you have that number handy? This Ahmed Ouaou from our License Renewal Group.

MR. POLASKI: Ahmed, why don't you just come up on front because you'll be up next. I don't know if we have that number handy, Dr. Armijo, but let's see. Ahmed.

MR. OUAOU: Dr. Armijo, the --

MR. GALLAGHER: Introduce yourself.

MR. OUAOU: Ahmed Oauau with License

Renewal. The buckling stress for the fueling load cases is 7.59 and the allowable is 7.59 with the safety factor of two and the assumed uniform thickness of 7.36. For the post-accident case, the allowable compressive stress is 12.93 and the applied stress is 12.0. So there is some margin, but it's not a very --

MEMBER BONACA: Post-accident. What about the case where you've flatten in the cavity and you're coming up to the vessel?

MR. OUAOU: This is the post-accident combination.

MEMBER BONACA: Okay.

MR. OUAOU: That's the notable combination.

MEMBER BONACA: And it's not limiting.

MR. OUAOU: That's correct.

MR. GALLAGHER: Yes, but this slide only talks about -- The question was related to buckling margin in the post-accident. So this slide doesn't apply, John, if we can move that off. Yes. Did that answer your question, Dr. Armijo?

MEMBER ARMIJO: Yes, I just wanted to make sure that the real limiting situation here that we're talking about is the buckling under during a refueling scenario.

MR. GALLAGHER: That's correct and again, the refueling scenario is with the cavity filled with water that occurs about two weeks out of every two years and it also had that conservative external pressure element onto the shell at two pounds external pressure.

MEMBER ARMIJO: Right. There's some debate about whether that's an appropriate thing to do.

MEMBER MAYNARD: Sam, and we're going to get into that more later. Right now, we're primarily going through the background and that we are going to be addressing some of these specific issues for the next set of presentations.

MEMBER ARMIJO: Okay.

MR. GALLAGHER: That's correct.

MR. O'ROURKE: Slide 19. To summarize the commitments that are part of our aging management program, we will continue to perform ultrasonic thickness measurements in various areas of the sand bed region and upper drywell region. Strippable coating will be applied to the reactor cavity liner every refueling outage. Leakage monitoring of the reactor cavity trough train and the sand bed trains will be performed daily during outages and quarterly between outages. We will perform visual inspections of the sand bed region, shell, epoxy coating and the seal at the junction between the drywell shell and the sand bed region floor. We will perform visual inspections and take ultrasonic measurements of the drywall shell in the trench areas until the trenches are filled in and we will visually inspect the moisture barrier inside the drywall at the junction between the interior drywall shell and the floor and the curbs.

I will show you a complete summary of our drywell inspections later in the presentation.

MEMBER BONACA: Okay. So you will have a summary of that.

MR. O'ROURKE: Yes, I do.

MEMBER MAYNARD: This is basically going back over what has already been put on the docket as part of the commitments.

MR. GALLAGHER: That's correct.

MR. O'ROURKE: So our overall conclusions for the Oyster Creek drywell are that the corrective actions to mitigate drywell shell corrosion have been effective. The drywell shell corrosion has been arrested in the sand bed region and continues to be very low in the upper drywell elevations.

CHAIRMAN SHACK: And your interpretation of that is that you are spilling some water over. It's getting caught in the firebar D and corroding, but you don't get enough moisture to come down to the drains.

MR. O'ROURKE: No, our conclusion is based on the fact that the trough drain is doing its job in keeping the water out of the sand bed region as we demonstrated.

CHAIRMAN SHACK: Why do you get corrosion then in the upper drywell?

MR. GALLAGHER: Yes. We're monitoring -- You know, we monitor the upper drywell and continue to do that. The corrosion rate that we have in that one location is very low. It's 0.66 mils per year and we think we're conservatively that an on-going corrosion.

CHAIRMAN SHACK: I see. It's just noise in the data.

MR. GALLAGHER: But it is -- If there was corrosion, the upper drywell would be more susceptible because it's not epoxy coated. We epoxy coat at the sand bed region and the upper drywell had red primer. It does have the firebar D there, but we think that's a conservative call.

MR. O'ROURKE: And your backup books at Tab 4 have these trend graphs for the upper drywell region for the thirteen areas that we monitor and they basically show a no corrosion.

(Off the record comments.)

MR. O'ROURKE: Our next conclusion is that the corrosion on the embedded portion of the drywell shell is not significant as we just noted. The drywell shell meets Code safety margins and we have an effective aging management program to assure continued safe operations.

MR. POLASKI: Thank you, John. We met with the ACRS subcommittee on January 18th. We had a lot of very good discussion on many different aspects of the condition in the drywell shell. From these discussions especially at the end of the meeting when the ACRS members communicated their positions from the topics that had been discussed, we left that meeting with five issues that needed to further discussion today. The five issues are listed on this slide.

We will discuss the reasons why the use of a modified capacity reduction factor is appropriate for the buckling analysis that was performed in 1992. We also discussed our position on the adequacy of our current analysis and plans we have to perform a modern three-dimensional finite element analysis of the Oyster Creek drywell. We will address your concerns in the water leakage through the reactor cavity liner. We have a table that shows the extent of the monitoring that was performed on the drywell shell and we will also discuss the situation with water discovered during the 2006 refueling outage in the two trenches that were excavated in the floor in the drywell interior in 1986. For each of these issues, we will present the issue that the subcommittee members had as we understood it when we present our response on each including information that should close each of these issues. Next slide please.

The first issue that we understood deals with the capacity reduction factor. As we understood it, the GE analysis and Sandia analysis are different. The key difference is that the General Electric analysis increased the capacity reduction factor for the refueling load combination case when there is no internal pressure present. The question is is this acceptable. Our response to this is that the increased capacity factor using GE's analysis is acceptable. Next slide please.

This presents our conclusions dealing with the capacity reduction factor. In the next slides and our next set of presenters, we will present the details to the basis for these conclusions. I'd like to point out the third and fourth conclusions. The third one is that the application of increased capacity reduction factor from the Sandia analysis produces results similar to the General Electric analysis and (4) AmerGen's conclusion is that the General Electric analysis including a middle uniform thickness in the sand bed region of 736 mils is a valid analysis.

We have with us today Dr. Hardiyal Mehta of General Electric, Dr. Clarence Miller, formerly with Chicago Bridge and Iron, and Mr. Ahmed Ouaou of the Oyster Creek License Renewal team who will present information to support the use of modified capacity reduction factor.

Dr. Mehta prepared that analysis to determine that determined the minimum required thickness of the drywell shell. Dr. Miller who is the author of Code Case N-284 will provide information on the correctness of increasing the capacity reduction factor because of tensile stresses in the drywell shell. Dr. Miller will describe how tensile stresses in the orthogonal direction increased the capacity reduction factor. These tensile stresses can result either from internal pressure or from mechanical loading. And lastly, Mr. Ahmed Ouaou will present information on the results of some work we have done with the Sandia analysis that shows that application of the capacity factor and how it compares to the General Electric analysis.

To begin with, Dr. Mehta will briefly discuss the methodology that was used based on Code Case N-284 to perform the buckling analysis, particularly the use of a modified capacity reduction factor. Dr. Mehta.

DR. MEHTA: Thank you, Fred. Good afternoon. The next slide. This slide provides the details of the buckling analysis that was conducted. The GE buckling analysis followed the methodology outlined in ASME Code Case N-284. In this methodology, the allowable compressive stress is calculated using the equation as shown here in which first is eta sub I which is the plasticity reduction factor which comes into play. It takes into account plasticity effects if the calculated compressive stress exceeds elasticity.

The second term is alpha sub I which is the capacity reduction factor. This factor accounts for the reduction in buckling stress as a result of the presence of any imperfections in actually fabricated shells. These imperfections even though they are within the ASME Code allowable limits do affect the third degree calculated stress because they deviate from the third cone shape that's assumed in the finite element analysis.

And then the third term, sigma sub ie, is the critical last buckling stress which is calculated using the finite element analysis and the final factor is the factor of safety which in this case was assumed at 2.0 in the inputting condition 2:02 condition and 1.67 for post-accident condition which is consistent with the N-284 guidelines.

The capacity reduction factor alpha sub I was further increased to account for the fact of co-existing orthogonal tensile side stress. The increase was based on tests conducted on cylinders and as Dr. Miller will discuss in his presentation test conducted on spherical segments concluded that the modified alpha sub I based on cylindrical test results is suitable to use in this application.

MR. POLASKI: Thank you, Dr. Mehta. Dr. Clarence Miller will now discuss the appropriateness of using a modified capacity reduction factor for the buckling analysis of the drywell shell. Dr. Miller is currently an independent consultant specializing in design of shell structures. He worked for 44 years for Chicago Bridge and Iron as their chief structural engineer. We would note that CB&I designed the fabricated Oyster Creek drywell. Dr. Miller conducted hundreds of tests on buckling of cylinders, cones, spheres and four spherical heads. He was responsible for design criteria for structures built by Chicago Bridge & Iron and also worked on ASME Code committees. He was the primary author of Code Case N-284 and also the primary author of Code Case 2286. Dr. Miller.

DR. MILLER: Thank you, Fred. The ASME Code Case N-284 allows modifying the capacity reduction factor to account for the effective orthogonal tensile stress on buckling. N-284 does refer to the effective internal pressure; however, the hoop tension develops on a sphere as a result of axial compression or internal pressure.

The effected of the orthogonal tensile stress due to internal pressure is well documented on cylinders and the N-284 capacity reduction factor was modified using formulas which I developed based on tests conducted on cylinders. Tests have been conducted on spheres without internal pressure which show that the co-existence of orthogonal tensile stress reduces the effective imperfection on the buckling strength of spheres. Again, I comment the orthogonal tensile stresses in these tests are a result of in-plane tension or compression modes. This modified capacity reduction factor which I have developed is also now incorporated in ASME Section 8 Code Case 2286-1 for spheres.

CHAIRMAN SHACK: Now does the language of the Code case refer to internal pressure?

DR. MILLER: No longer -- Those words are probably my fault because I was just so used to using the terminology "effective internal pressure" from spheres. So that has been corrected in this later Code case in Section 8.

So the next figure I'm going to show you how the modified formula is conservative for spheres. The vertical scale is the capacity reduction factor alpha and alpha is defined as a ratio of the maximum compressive buckling stress divided by the theoretical buckling stress. The horizontal axis is a ratio of sigma 2 over sigma 1. Again, sigma 1 is the maximum compressive stress at failure of the sphere. This is the same as my terminology of sigma critical up there.

MEMBER ARMIJO: Sigma 1 you use the term "failure." Do you mean buckling?

DR. MILLER: Yes. Even though I probably should have been consistent to show sigma critical as also sigma 1 in this figure.

MEMBER ARMIJO: Right.

DR. MILLER: Sigma 2 is the orthogonal stress and sigma 2 covers the whole range from both tension and compression or sigma 2 over sigma 1 greater than zero. Sigma 2 is compression. If sigma 2 over sigma 1 is less than zero, sigma 2 is tension. I want to point out that on the upper right the symbols alpha should be shown as sigma there.

Now alpha is equal to alpha sub zero plus alpha sub p. Alpha sub zero is the value of alpha at sigma 2 over sigma 1 equals zero. Alpha sub p is the increase in alpha due to the tensile stress sigma 2. The lower line which I labeled "Miller" gives the values of alpha p which we're using for the modified vector.

This is a modification made to ASME Code Case N-284. The equation for alpha p was derived from many tests on cylinders and based on my studies, I concluded that this equation could also be used for spheres. Later tests performed by Odland and Yao show this equation to be conservative for spheres.

In their tests, the tensile stress resulted from in-plane mechanical loads rather than internal pressure. There were a total of 17 different test shells with ROT values of 444 to 1600. So they definitely cover the range of the Oyster Creek shell. The upper line I show there was derived by Odland as a lower base on his tests. The Yao tests are shown to also fall above this line. This figure shows that the modification made to N-284 is conservative for spheres. Also it shows that the tensile stress need not result from internal pressure and reiterating once again, that this modified capacity reduction factor is now included in ASME Section 8 Code case 2286-1. This Code case no longer makes reference to increase due to internal pressure.

MR. POLASKI: Thank you, Dr. Miller.

MEMBER ARMIJO: Where would you -- From these curves, where would you pick the appropriate alpha sub I for Oyster Creek?

DR. MILLER: For the Oyster Creek shell, we're approximately somewhere near less than .05, minus 0.5.

MEMBER ARMIJO: Okay. So go down to -- So alpha sub I is -0.5 so it's --

DR. MILLER: That's where we only have an increase of 0.25, I believe, is what will be shown.

MR. GALLAGHER: Yes, I think the number was 0.326 for the --

MEMBER ARMIJO: Where is it on the chart? Just put the pointer on that spot.

MR. GALLAGHER: The 0.326 on the red line.

MEMBER ARMIJO: And -0.5 on the ratio.

DR. MILLER: That's actually between zero and 0.5.

MEMBER ARMIJO: It's between zero and 0.5. Okay. So somewhere in here is where that is, Oyster Creek.

MR. POLASKI: Any other questions? Thank you, Dr. Miller. We've now heard from Dr. Mehta about how a modified capacity reduction factor was used in a GE analysis and from Dr. Miller about the basis for why this was correct. Mr. Ahmed Ouaou will now present information we have presented on the impact of the flying and modified capacity reduction factor to the results of the Sandia analysis. Mr. Ouaou.

MR. OUAOU: Thank you, Fred. Good afternoon. In the next two slides, we will demonstrate the results of modifying capacity reduction factor using the methodology described by Dr. Miller. To illustrate the impact of the modified capacity reduction factor on the buckling stress and on the safety factor, we used results of the Sandia analysis shown in the second column of this table. As you can see, the analyzed thickness is 0.842 inches or 842 mils and the capacity reduction factor used by Sandia is 0.207. We then modified the capacity factor using an orthogonal tension in-set bed region of 2.5 psi and as a result of that modification, the capacity reduction factor increased to 0.272 as shown in the third column about row no. 8.

CHAIRMAN SHACK: No, of course, this is not the uniform thickness Sandia calculation. So using the 0.842 is a little misleading.

MR. OUAOU: This is for illustration purposes. The next slide will show what we used, the actual uniform thickness of 0.844 that Sandia used.

CHAIRMAN SHACK: But this is their shot at the current best estimate, full three dimensional condition.

MR. OUAOU: Right. That's correct.

MR. GALLAGHER: That's correct.

MR. OUAOU: Increasing the capacity reduction factor --

MEMBER ARMIJO: Excuse me. Just to make sure I understand. When you did this, the 0.272, is that exactly the same factor that Dr. Mehta used in the GE analysis.

MR. OUAOU: No, it is not the same value.

It is less. The Dr. Mehta value is higher. It's 0.326 and because this tension is less, this number dropped down.

MEMBER ARMIJO: Okay.

MR. OUAOU: The results of modifying the capacity factor as indicated in the last row showed an increase of a factor of safety from 2.15 to 2.83. Next slide please.

This slides illustrates in graphical form the impact of the modified capacity reduction factor on the safety factor. The bottom of the red line was drawn using the data from Sandia analysis. In this case, the data we used is the uniform thickness of 0.844 inches and uniform thickness in the upper side of the line of 1.15 which is nominal thickness for the sand bed region.

Using those thicknesses, we modified capacity factors according to the methodology described to you before and the second or the blue line illustrates a shift upwards of the safety factor. The safety factor for instance for the 0.844 increased from 2.0 to 2.63 and the safety factor for the upper points increased from 3.85 to 5.46.

In the lower left-hand side of this chart, we do indicate that the 736 mil thickness used in the

GE analysis, the uniform thickness, with the calculated factor of safety of 2.0 and the bottom line is that if you look at this chart you would conclude from it that the significant factor between the Sandia analysis and the GE analysis is the capacity reduction factor and if you modify the GE analysis to take into consideration the orthogonal tensile stress, the results are consistent.

MR. GALLAGHER: You mean modify the Sandia analysis.

MR. OUAOU: Sandia, yes. That's a correction.

MEMBER MAYNARD: So I understand. That top line, the dark one on this one, that is using the Sandia calculation at the thickness that Sandia used as their average thickness using the modified capacity factor there.

MR. OUAOU: That's correct.

MEMBER ABDEL-KHALIK: The chart though as presented by Dr. Miller, this is essentially a generalized chart for an ideal geometry. One is a sphere and the other is a cylinder. The question is we don't have a sphere. We don't have a cylinder.

DR. MILLER: It is not an idealized. This is actually an equation for a sphere or cylinder with a given imperfection or deviation from true shape. With the sphere, I'm saying that these equations are valid if the sphere is constructed within the tolerance requirements of the ASME Code and that tolerance is e/t where e is the deviation from true theoretical shape. t is the thickness. e/t less than or equal to one and that is measured over a wavelength or an arc length of 3.72 square to rt.

The blue figure that I had shown you before, if you'll note up there, it's actually quite conservative because you'll see I have an e/t of 1.8. So I've actually taken his equation and applied a fairly large imperfection and I selected a 1.8. That would not be permitted on a sphere, it would have to match the point where sigma sub p of one. That's how I arrived at the 1.8. If I were putting one in the blue line it would be significantly higher than it is there. So what I'm saying is that this alpha is based on measured tests.

MEMBER ABDEL-KHALIK: The bottom line, I mean, these graphs are empirical based on experimental measurements.

DR. MILLER: Yes. Correct.

MEMBER ABDEL-KHALIK: And the experimental measurements were done on ideal geometries.

DR. MILLER: No.

MEMBER ABDEL-KHALIK: Were they done on geometries that looked like --

DR. MILLER: -- wrote that on fabricated shells, shells with initial imperfections.

CHAIRMAN SHACK: Right, but they didn't have vent lines or complex shapes.

MEMBER ABDEL-KHALIK: That's the point.

CHAIRMAN SHACK: They were spheres and cylinders.

DR. MILLER: Okay.

MEMBER ABDEL-KHALIK: That's the point I'm trying to make. So how do we know that these generalized charts apply when the geometry is significantly different than what I would call an ideal sphere or an ideal cylinder?

DR. MILLER: Well, to give you an example, I ran a set of tests on the effect of an opening in a cylindrical shell that was 1/4 of the circumference in order to determine how we needed to reinforce that opening. So these similar rules are used on containments to reinforce in areas of penetration and so forth so that the buckling is determined by the membrane stresses, not by maximum vending stresses. So by doing the finite element analysis, they can determine the maximum membrane stresses in these shells and I'm suggesting that the alpha values will apply then.

MEMBER ABDEL-KHALIK: Thank you.

MR. POLASKI: We'd now like to go onto to our next portion of the presentation.

MR. GALLAGHER: Slide 29.

MR. POLASKI: Slide 29. Now I would like to speak to the SER that was prepared for the NRC which accepted the Oyster Creek analysis to determine the Code required drywell shell thickness. In April 1992, the NRC issued a safety evaluation report which concluded that the analysis performed by General Electric accurately analyzed the Oyster Creek drywell shell for buckling during design basis loading conditions and that 736 mil was an acceptable criteria to use when performing ultrasonic thickness measurements of the drywell shell.

During the review of the General Electric analysis, there was numerous exchanges of technical information between the Licensee, General Electric, Code case experts and the NRC in the early 1990s. In its SER, the staff discussed the methodology Oyster Creek used to perform buckling analysis and specifically addressed the use of a modified capacity reduction factor. The GE analysis was reviewed by Brookhaven National Laboratory in support of the NRC staff review. And the NRC Staff concluded that the drywell meets ASME Section 3 Subsection NE requirements. Next slide.

These are our conclusions on the capacity reduction factor. The first is that the GE analysis in 1992 increased the capacity reduction factor from 0.207 to 0.326 to account from orthogonal tensile stresses in the sphere. Secondly, the buckling test conducted on spheres show a reduction in the effected imperfections of the buckling strength. Third is that the application of an increased capacity reduction factor in the Sandia analysis produces results similar to the GE analysis. And lastly, AmerGen's conclusion is that the GE analysis concluding a minimum, uniform thickness in the sand bed region as 736 mils is valid.

So this completes our presentation on the capacity reduction factor.

MR. GALLAGHER: Dr. Shack, so that was the -- Issue No. 1, we still have four other ones. Any comments or questions?

MEMBER MAYNARD: I'd say go ahead and move onto item two there.

MR. GALLAGHER: Okay.

CHAIRMAN SHACK: That was very helpful.

MR. POLASKI: The second issue that the subcommittee raised was that the thickness margin may be better understood with a modern three-dimensional finite element model with various thickness and thickness configurations in the sand bed region could be evaluated. And our response is that (1) our current licensing basis analysis demonstrated that the Code requirements were made and that's what we've just been discussing; (2)because the GE model used a uniform thickness corresponding to the lowest average thickness measured, we agree that use of a modern modeling technique inputting actual shell thicknesses should demonstrate more thickness margin and a larger safety factor; and lastly, in order to better understand the margin that is available for the Oyster Creek drywell shell, AmerGen will be performing a 3-D finite element analysis of the Oyster Creek drywell. This analysis will be completed prior to entering the period of extended operation.

MEMBER MAYNARD: Just to make sure I understand because I believe that Item 3 is a new commitment that we had not discussed or talked about.

MR. GALLAGHER: Yes, that's correct, Mr. Maynard, but we're trying to address the issues that you all brought up and this is a new commitment. It is a significant commitment on our part and we will do that.

MEMBER MAYNARD: Okay. And I wanted to make sure that your position, you would be willing -- you would be making this as a commitment to be done, not just something that you're thinking about doing.

MR. GALLAGHER: That's correct and we will send in a letter with this commitment following the meeting.

MEMBER MAYNARD: Okay. I don't think any of the members would tell you not to do that.

(Laughter.)

MR. GALLAGHER: We didn't think so.

MR. POLASKI: Mr. John O'Rourke will now present the other three subcommittee issues, those being the issue with the reactor cavity liner leakage, future monitoring programs and the interior surface of the embedded drywell shell. John.

MR. O'ROURKE: The next issue from the January 18th subcommittee meeting was that the leakage through the reactor cavity liner should be eliminated. We agree that eliminating the liner leakage would be desirable. Our current program is designed to control this leakage to ensure that no water gets into the sand bed region and it was proven successful during the 2006 refueling outage. However, based on the subcommittee's input, we have decided to perform an engineering study prior to the period of extended operation to investigate cost effective replacement or repair options to eliminate this leakage.

MEMBER MAYNARD: This one when I read this the first time, I was more excited than after the second time.

(Laughter.)

MEMBER MAYNARD: I see a commitment to do an engineering study, but the way I read this that's not necessarily a commitment to actually --

MR. SIEBER: Do anything.

MEMBER MAYNARD: -- do anything. Would you clarify that?

MR. GALLAGHER: I will clarify that. I mean our intent is to find a solution here. As we talked about last time to the subcommittee and Dr. Bonaca, this is a difficult repair situation. So we want to find a solution. We want to implement a solution and that's what this is about. Will we find a solution that's cost effective? I hope so and that's what we're trying to do.

MR. SIEBER: And right now, you're using

duct tape and paint, right?

MR. GALLAGHER: We're using strippable coating and metallic tape. That's correct.

MEMBER MAYNARD: I'll tell you. My issue is I understand that right now the leakage is within the capacity of the drain. However, the drain is there as a backup in case there's a failure of some components, some leakage, unexpected leakage or whatever. So by counting on that as part of normal operations, you've reduced your margin to any additional leakage or whatever.

The system, the design intent, is to not have any leakage and it is bothersome to still have some leakage and be willing to live with that. I know that you would like to fix it. I'm just not sure that -- We'll have to see how others feel about how strongly the stuff is here. I appreciate what you're doing here.

MR. GALLAGHER: We believe the feedback we did get from Dr. Bonaca was that cost effective could come into it. I do have our Senior VP here, Rich Lopriore, who he is behind this 100 percent and wants to make sure we find a solution.

MR. LOPRIORE: Yes. I'm not as tall as the other guy.

MR. GALLAGHER: This is Rich Lopriore, our Senior VP.

MR. LOPRIORE: I'm Rich Lopriore, the Senior VP from Mid Atlantic Operations. I am responsible for Oyster Creek in my area of responsibility. We agreed. We certainly want zero leakage and that is fundamentally what these studies are going to do.

But we want to make sure we know what is the right approach to this. I think at this point without studying this further, we don't know exactly what that is. It could be a membrane. It could be welding a new skin, but there are complications with all of that.

So it's not for not wanting to put investment into the plant. We clearly want to invest in the plant and we share the Committee's concern about wanting to achieve zero leakage. We will pursue that very vigorously and come up with the right answer. In the meantime, we do agree that we have a way to manage and by no means does that mean it's going to stop us from trying to get zero leakage.

MEMBER MAYNARD: I understand and I appreciate that and I can understand the difficulty in making a commitment doing something that you don't know what the answer is. So I understand that, too.

MR. SIEBER: The problem is not as simple as it may first appear because of the stresses. You can't weld on that very well. This isn't the only one that leaks. That's exactly what we've said. This is not a unique problem. On the other hand --

CHAIRMAN SHACK: You've got to permit it after it's fixed.

MR. SIEBER: Yes.

MEMBER MAYNARD: It's a building where you're relying just one drain, too.

CHAIRMAN SHACK: That's the other thing. I was going to ask if anybody put a ball bearing on that lip up there just to see how well it rolls around. One drain?

MR. POLASKI: The design -- This is Fred Polaski. The design of that is about a two inch drop away from the side 180 degree away from the drain to the drain. The design, I can't guarantee that it's two inches, whatever the design was. So that built into the design.

MEMBER MAYNARD: And it should be higher on the side that doesn't have the drain.

(Laughter.)

CHAIRMAN SHACK: I hope it's better than

my gutters.

MR. SIEBER: Yes. In any event, I consider this a challenge to you and I'm interested in it. So I will follow what it is you do to solve the problem.

MR. GALLAGHER: Okay. We understand.

MEMBER ABDEL-KHALIK: Is that area of the damaged lip accessible?

MR. POLASKI: The area of the damaged lip when they did the repairs, they had to cut actually holes in the, I call it, the floor in the reactive cavity to gain access to that. It's not readily accessible. The way they do the visual is through four scope of fiber optics up through the drain line to see in that area. Difficult to get to.

MEMBER ABDEL-KHALIK: Have you considered increasing the height of that lip?

MR. GALLAGHER: We repaired the lip is what we did and as we said in this outage, we showed that all the leakage was controlled and not going into the sand bed region. So we think we have that lip fixed. This is really get back up -- You know, the feedback we got from you all was getting back up to stop it from getting there in the first place and that's what we're going to focus on in this study.

MEMBER ABDEL-KHALIK: Thank you.

MR. O'ROURKE: Moving on. Slide 33. The next subcommittee comment that I will address is the monitoring of the drywell shell thickness should be more aggressive in the short term. At the subcommittee meeting on January 18th, we did not adequately explain the breadth and frequency of our monitoring activities. We prepared a summary of these activities and provided them to the Committee as a handout and that's the 11" X 17" that I referred to earlier. I'll discuss the monitoring in detail using your handout and the next slide.

This slide summarizes the monitoring activities for the drywell shell beginning with the activities performed during the most recent outage through the period of extended operation. The table is divided up into four major areas. The first area contains the activities we used to verify that there is no water leakage into the sand bed region.

The second area identifies the upper drywell shell monitoring. As we had previously described to the ACRS subcommittee, the monitoring locations for Item 2 were established based on extensive examinations performed over several years. Once the monitoring locations were established, inspections had been performed since 1987 and will continue through the period of extended operation.

The third area identifies the monitoring of the sand bed region. In addition to the inspections that are performed inside the drywell, we have included visual and ultrasonic inspections performed from outside the drywell in the sand bed region.

Finally, we will continue with our structures monitoring program which includes visual inspections of the interior drywell concrete floor, sub-pile room floor and trough, and the shell every outage and sump inspection every other outage, performance of the integrated leak rate test every ten years as required by the technical specifications, visual inspections of the service level one coating on the inside of the drywell every other outage and based on a corrective action implemented during the 2006 refueling outage, visual inspection of the moisture barrier installed between the drywell shell and the concrete curb and floor inside the drywell.

MEMBER MAYNARD: Just to make sure I'm not reading something into it or not getting something, is this a summary of what you have already provided and discussed and committed to?

MR. GALLAGHER: Yes, with one clarification, Mr. Maynard. The Item No. 6 in the sand bed region says "inspection for water in trenches." We do have a commitment on that and we are suggesting to modify that. I think that's Issue No. 5 based on your feedback from the last meeting and we would again send that in in a commitment letter.

Right now, for those trenches, we said that we would look at them next time and then fill them in, you know, restore them. What we're going to commit to in the future is that we would check them and assuming when we verify that our corrective action has been effective by the fact that there's no water in those trenches for two outages in a row, then we would restore them.

MEMBER MAYNARD: So it's a matter of a couple of outages of looking at it before you fill them in.

MR. GALLAGHER: That's what we're proposing in the, I guess, it's Issue No. 5. But other than that, these are all previous items that we've committed to and we thought that in -- The reason we presented this here is we thought we heard some comments from you on maybe the program needs to be more aggressive in the short term. So we think we didn't communicate to you exactly the depth and breadth of what we have and so we think this table really shows that and we think that the drywell is well covered top to bottom in the inspections and the aging management program.

MR. O'ROURKE: Slide 35. During the January 18th subcommittee meeting, some members comment that the trenches should not be filled in until we have verified that we have eliminated the water on the interior shell which we just discussed. The source of the water has been identified and corrective actions have been implemented to prevent additional water from coming in contact with the steel shell.

On January 18th, we presented the subcommittee with information that supports that corrosion of the embedded shell is mitigated by the high pH pore water in the concrete and is further protected by a passive film that has formed on the steel surface.

This slide shows the interior of the drywell and the sub-pile room. Leakage inside the drywell from control rod drives, valve packing equipment, etc. is an expected condition both during operation and during refueling outages. Normally, this leakage is very low. Currently, there is less than 1/10th of a gallon per minute of leakage inside the drywell at Oyster Creek which is well below the tech spec limit of 5 gpm.

The interior of the drywell was designed to route all leakage to the drywell sump in the sub-pile room. Leakage inside the sub-pile room is directed to a collection trough around the parameter that drains into the sump. Leakage outside the sub-pile room is directed to the collection trough via drain pass through the reactor pedestal. The sump has redundant pumps that automatically pump the leakage out of the drywell based on level in the sump.

During the 2006 outage, defects were noted in the collection trough and we identified that the gap between the interior shell and the concrete floor and curb were not sealed. Both of these would have allowed water to get into the trenches and between the shell and concrete inside the drywell. Corrective actions were implemented to fix both of these conditions. Based on these corrective actions, we do not expect any additional water to come in contact with the shell below the concrete.

MEMBER ARMIJO: Now part of it -- There are two -- Would you just point out the locations where those sources of water are? Condensation on the shell at the curb or --

MR. O'ROURKE: The water comes from equipment leakage during the chilling outage phase.

MEMBER ARMIJO: Yes, I understand that part.

MR. GALLAGHER: We just sealed the curb area just in case any water could come down on the shell and then get there and then get into a little gap. So we sealed that to make sure that that wouldn't happen.

MR. O'ROURKE: And the collection trough inside the sub-pile room had some defects that we have repaired that would prevent water from getting through the concrete into the --

MEMBER ARMIJO: And out to the shell.

MR. O'ROURKE: Right, and into the shell.

MEMBER ARMIJO: Good.

MEMBER MAYNARD: You call that -- Is that the sump power room? Is that what you're saying?

MR. O'ROURKE: Sub-pile room.

MEMBER MAYNARD: Sub-pile room. Okay.

MR. GALLAGHER: Yes, that's the area of under vessel.

MEMBER MAYNARD: Under the reactor.

MR. GALLAGHER: Which is within the reactor pedestal.

MEMBER MAYNARD: I'm a PWR guy.

MR. O'ROURKE: So on slide 37 based on the subcommittee feedback, we will continue to inspect the trenches during refueling outages for the presence of water and we will use the presence of water to monitor that our corrective actions have been effective. In addition, visual and ultrasonic inspections of the shell within the trenches will be performed during refueling outages. If our monitoring confirms in two consecutive refueling outages that our corrective actions have been effective in eliminating the water in the trenches, we will restore the trenches to their original design condition.

MEMBER MAYNARD: Just to clarify. There were some of the members who said the trenches should be filled in. There were some who said they should be left open and there were a couple, at least one of us, who says open for awhile and then fill it in.

MR. O'ROURKE: You took the middle. That's smart.

MR. SIEBER: It's a good way to collect all the water in the trench area.

MR. POLASKI: That concludes our

presentation on the issues with the drywell.

MEMBER MAYNARD: Anybody have any of those five we need to go back over again? Okay.

MR. GALLAGHER: Okay. Dr. Shack, so we do have an overall LRA presentation. Would you like us to go through it or -- We did present this at the subcommittee meeting on October 3rd. It is just a general summary of our application. Bottom line we can just go to the bottom line conclusion if you'd like or if you would like us to go through, we can do that.

CHAIRMAN SHACK: I'd be happy just to go myself.

MEMBER MAYNARD: To what?

CHAIRMAN SHACK: To the bottom line conclusion.

MEMBER MAYNARD: Yes, I think that at most of our subcommittee meetings we had the majority of the members there. We have the information here that can be read by anyone who needs it. So I would go straight to the --

MR. POLASKI: Let's to go the last slide, Slide 45. These are our overall summaries and conclusions. First, aging management programs that have been established to ensure safe operations for the period of extended operation. The license renewal commitment will be implemented as effected and we are on track for implementing activities. That concludes our presentation.

MEMBER MAYNARD: Unless there are any questions, we're at a good point to take a break.

CHAIRMAN SHACK: Well, I was going to suggest we just keep on going.

MEMBER MAYNARD: Okay.

CHAIRMAN SHACK: No? Okay. We'll take a break.

(Laughter.)

MEMBER MAYNARD: You'd better say how many minutes.

CHAIRMAN SHACK: A 15 minute break. Let's come back 2:55 p.m. We're running slightly ahead of schedule or pretty much on schedule. So we're getting caught up. So 2:55 p.m. Off the record.

(Whereupon, the foregoing matter went off the record at 2:41 p.m. and went back on the record at 2:57 p.m.)

MEMBER MAYNARD: Okay, I'd like to get started again. Okay, I'd like to go ahead and resume the afternoon session here for the license renewal application review for Oyster Creek and I'll turn it over to the staff. I believe Donnie will take care of that.

MR. ASHLEY: My name is Donnie Ashley and I'm the Project Manager for the Oyster Creek License Renewal effort. And as part of my introduction, the path we're going to follow this afternoon is different, you'll notice from what you normally see in these kinds of presentations to the full committee.

What I'd like to do is discuss license conditions with you, the conditions that we have talked about in the updated SER in December of last year and some other conditions that we're looking at and then I'm going to turn it over to Sujit Samaddar and Hans Ashar to talk to you about confirmatory analysis and to give plenty of time. So I've moved those two items up out of the presentation to the front so that we could get plenty of time to discuss them as you want to.

In the December SER, there were three license conditions in that document and these are relatively standard conditions that you see in most all license renewal. They talk about updating the SER, the UFSAR supplements and requirement -- future activities be identified in the UFSAR and surveillance calendar that should be retained.

You've heard a lot of information from the Applicant this afternoon about some commitments that they have made and commitments that they're planning to make. One of the things that we have done is we've been looking at this application, we've had audits, A&P audits and our audits. We've had inspections done by the region and based on all of that that we've been looking at since July of 2005, we have two proposed license conditions that we plan on putting into the final SER.

The first one would require the Applicant to increase the frequence of the drywell inspections and the ultrasonic testing in the sand bed region to all 10 days, every other refueling outage for the period of extended operations. We realize that regardless of which calculation you use, they all point to the fact that the safety margins have been maintained. However, the margins to the safety factors are very small. So as a result, we would like to see the Applicant increase their monitoring in the sand bed region.

The last license condition would require the Applicant to monitor at every refueling outage and maintain the two trenches located inside the drywell open until such time that the Applicant can demonstrate that the source of the water are identified and eliminated.

MEMBER MAYNARD: I'd like to ask you from what the licensee or the Applicant had provided in their presentation, of what they're committing to or willing to commit to, is that consistent with this second bullet here or not?

MR. ASHLEY: It's consistent with the second bullet. The first bullet is different.

MEMBER MAYNARD: Right, I noticed that but the second one, because they had committed to look at it for like three in a row here, two or three in a row and then close it in. Okay.

MR. ASHLEY: What we wanted to do was insure that they would consult with us before taking those kind of actions on their own.

Member MAYNARD: Okay.

MEMBER ARMIJO: Would you still require the increased UT inspection frequency if the Applicant implemented a permanent repair of the leakage in the cavity liner?

MR. ASHLEY: It would --

MEMBER ARMIJO: I mean, if they demonstrated that they had fixed it once and for all.

MR. ASHLEY: Yes, sir.

MEMBER ARMIJO: And showed you, then you would reconsider.

MR. ASHLEY: We would reconsider and I think that's a good way to put it. The license condition would give us that option to reconsider.

CHAIRMAN SHACK: You could also put a performance base that if they show no thickness loss X outages, then you would reconsider.

MR. ASHLEY: Yes, sir, and we're working with the technical staff and with the folks over in licensing to determine the appropriate language to make sure that this is covered.

MR. SIEBER: I do think, though, that you would have to follow the time regiment that Dr. Jackson (phonetic) established that there is no further degradation.

MR. ASHLEY: Yes, sir, we would expect some demonstration of some positive indication that they corrected it. We also want to make sure that we increase and maintain the monitoring that they're going to do.

MR. SIEBER: Now, this is just the sand bed area but you have thinning in the upper drywell, too.

MR. ASHLEY: The staff feels that the

programs that are implemented, the aging management programs for the rest of the drywell is adequate. And with that, I'd ask Sujit Samaddar if he would, to talk to you now about the confirmatory analysis.

MR. SAMADDAR: I'm Sujit Samaddar and I have Hans Asher with me over here and we are both from the Office of Nuclear Reactor Regulations. We concluded the last presentation to the ACRS without reconciling the average difference between the computed minimum shell thickness between the 1992 G analysis, the current licensing basis and the NRC/Sandia 2006 confirmatory analysis.

This issue is the context of our current presentation. The -- I'd like to go back one more slide. The issue was -- it was asked of us to explain the aberrant difference in the computed minimum shell thickness between the 1992 G analysis and the current analysis of record and the 2006 NRC/Sandia confirmatory analysis. The confirmatory analysis suggested that the thickness of .84 inch is appropriate for maintaining a factor of safety of 2, which the 1992 G analysis established that smaller thickness of .736 would be adequate to maintain the desired factor safety of 2 against buckling.

So we have two objectives that we need to meet. Next slide. These objectives are explain the aberrant difference between the two analysis and reconfirm the appropriateness of the 1992 G analysis as the current licensing basis. As we go through this presentation, we'll establish that the 1992 G analysis and the 2006 NRC/Sandia analysis has established that the Oyster Creek drywell meets the ASME code requirements.

In the next part then we will also establish at this point that a factor safety greater than 2 is achieved if the factor of hoop tension is included in the NRC/Sandia analysis for a uniform shell thickness of .844. This slide is basically an overview of the relationships that we have. Okay. A drywell analysis consists of essentially two parts and the reason I'm going through this is for those of you not present in the earlier presentation, this overview illustrates the fact that the acceptability analysis of the drywell requires the drywell shell thickness be acceptable from all the stress criteria and the stability criteria and the buckling criteria of the ASME code. Performance of the ASME stress criteria was demonstrated in the previous presentation.

The stability criteria is the issue of our present discussion. Next slide, please. The GE 1992 analysis, the licensing basis, has determined that the minimum shell thickness for factor safety equals 2, ASME code criteria, included hoop tension in calculating the minimum shell thickness and the hoop tension develops as a result of actual compression on sphere or internal pressure. And it was accepted by analysis as the current licensing basis. The analysis acceptance of the license's approach was stability evaluation of Oyster Creek drywell shell was based on the rationale that the hoop tension, comparing to stress is caused by compressive loading on the spherical shell.

This tests stress of the stretching effect on the shell reducing the averse effect of imperfection in the shell. The licensee has considered the contribution of the tension hoop stress in the computation of the required minimum thickness to meet a factor safety of 2. The licensee has determined that the minimum shell thickness of .736 will be necessary in the sand bed region to meet the ASME stability requirements. They have also considered the fact that there was sufficient passage in the drywell to preclude any general buckling failure under the possibility of the condition.

In our NRC/Sandia analysis, which is the confirmatory analysis, these are the things we did. We determined the required minimum shell thickness for a factor safety of 2.0. Hoop tension developed as a result of actual compression of the spherical portion of the drywell shell was not included in the analysis, in the determination of the minimum shell thickness. In essence, confirmatory analysis performed by Sandia of the drywell shell uses assumptions that did not consider any contribution of the shell circumference inside stress in the shell and the buckling evaluation. The intent of that analysis was to independently confirm the general conclusions reached by the licensee's analysis and compliment stock evaluation of the license renewal request.

The Sandia analysis determined for the minimum shell thickness of .84 is required in the sand bed region to meet ASME stability criteria of maintaining a factor of safety of 2. With the hoop tension computed in the Sandia analysis is included in the Sandia computation of the required minimum thickness, the computed factor safety is greater than 2 for shell thickness of .844.

Further, the Sandia analysis is based on the assumption of uniform shell thickness. Presence of thicker sections of the shell in areas increases the overall buckling of the shell.

MEMBER APOSTOLAKIS: What does it mean, would result?

MR. SAMADDAR: Oh, so if you include the effect of hoop tension in the analysis Sandie, confirmatory analysis, the effect would result in NRC/Sandia analysis evening a required minimum thickness less than .74. If we include the fact of hoop tension, and using the --

MEMBER APOSTOLAKIS: You have to speak in the microphone.

MR. SAMADDAR: If we had included the effect of hoop tension in that analysis, confirmatory analysis, the result would have given us a thickness which would be less than .736.

MEMBER ARMIJO: Just read it in the equation, George.

MR. SAMADDAR: Yes, what we did was we took that Sandia analysis and in the Sandia analysis there was hoop tension that was already computed. We took this hoop tensions and used the same methodology that the licensee had used in the earlier computation and stuck the tension values into it and recomputed the numbers. And once we did recompute the numbers, we came up with a thickness for -- given a factor safety of 2, which would be less than .736.

CHAIRMAN SHACK: Of course, that's extrapolating from the calculations that Sandia did since they didn't actually do that calculation but you're extrapolating the line down to the thickness.

MR. SAMADDAR: Yes, but we actually moved the line up by using their --

CHAIRMAN SHACK: You still have to extrapolate off the end of the line.

MEMBER ARMIJO: To me the key point is, does the staff agree that the hoop stress should be included and that capacity factor adjustment should be included and it's correct as Dr. Miller presented to us today.

MR. SAMADDAR: That is correct. He confirmed that that was the staff position. We had made that same determination in 1992. We made the same determination again in 2006.

CHAIRMAN SHACK: Okay, violent agreement.

MR. SAMADDAR: Excuse me?

CHAIRMAN SHACK: Violent agreement.

MEMBER MAYNARD: Just for some of the other committee members and I don't know if there's anyone here from Sandia, but Sandia had not used this modified capacity factor and as I recall from the discussion, they didn't say it didn't apply. They were saying that they, themselves, didn't have the information to justify it.

MR. SAMADDAR: That's correct.

MEMBER MAYNARD: So they weren't saying it can't be. They were just saying they didn't have the information to do it.

MR. SAMADDAR: That's correct.

MEMBER ARMIJO: Now that was a draft report, the Sandia report that at least I got to review was a draft report and so it's not complete. Now, will it be completed and it include the correct methodology?

MR. SAMADDAR: I mean --

MR. ASHAR: I don't think at this time we were obliged to do that because of the -- at that time we didn't do anything because the timing and resources at this time, but if there's a need for doing that, we can do that. It's not something that cannot be done. Because he's going to perform the analysis using the similar to what Sandia has done. That I think -- that's what we thing, but yes.

MR. SAMADDAR: Let me add a few more things. This is a confirmatory analysis and the purpose of the conformity analysis is not to substitute an older analysis or a newer analysis. It's simply a confirmatory analysis. So we -- it's done on the back of the envelope, we use something that was available of some computer modeling. So it was essentially a conformity analysis and we did not really feel that we have to go to the extent with a confirmatory analysis to like fine tune it to the point that it is at par with the licensing basis.

MR. HILAND: May I help answer the question, please? I'm Pat Hiland. I'm the Director of Engineering in the Office of Nuclear Reactor Regulation. As Sujit tried to articulate, it was our intent to use the Sandia analysis as a confirmatory analysis. We do not intend go back and contract for more details. We are satisfied that that analysis confirms the 1992 licensing basis. Thank you.

MEMBER ABDEL-KHALIK: When the Applicant completes the 3-D finite element analysis that they talked about earlier, will that be the analysis of record?

MR. ASHLEY: Right now, the analysis of record is the 1992 analysis. If they perform a new analysis, and go through the process of adding that into their new current licensing basis, then that would become the new analysis and that would be their process for applying for that.

MEMBER ABDEL-KHALIK: Now, that analysis essentially uses the current condition of the drywell in doing a realistic 3-D analysis and therefore, it does not -- it gives you a current value for the factor of safety. It does not give a bounding value for the minimum thickness. How would that analysis then be used in a licensing environment where you're monitoring the change in thickness with time? Would you require them to update the analysis every time they to a thickness measurement and they find that the thickness is different than the values they used in that 3-D analysis.

MR. KUO: This is P.T. Kuo. I would like to comment on that. The license renewal review is -- according to the rule, the license renewal review is based on current licensing basis. We do not have a requirement for anybody to update their current licensing basis as time goes on. In this case, just to answer your question directly, whether -- what will be the current licensing basis later on when they complete their analysis, we do not have requirement for them to substitute the new analysis into the current licensing basis but if they wish, they could submit an amendment, license amendment, and change the current licensing basis.

In that case, the staff will have review and approve it.

MEMBER ABDEL-KHALIK: Thank you.

MS. LUND: This is Louise Lund. I also wanted to clarify that the report was put out in final January 12th even though we had not changed this issue with the capacity reduction factor, we had not addressed it. I just didn't want -- I wanted to clarify the record that the report is out in final. I think what Sujit was trying to point out is, how we intended to use the report. We weren't trying to supplant the current licensing basis with the Sandia analysis.

We were -- they were using the Sandia report to understand, you know, the review in more depth.

MEMBER MAYNARD: I'm trying to understand. First of all, I think it's good that they're going to do an analysis. I'm not sure where the committee is going to come down on all this. My question comes in, they're going to have that done prior to the period of extended operation, if their license renewal application is approved.

Now, that's going to show either results that shows they have more margin or less margin than what they thought in the original analysis. If they show they have more, that's not an issue. What happens if they show they have less?

MR. ASHLEY: As long as they meet the code, the margin is the margin.

MEMBER MAYNARD: It would effect the rate or it would effect their monitoring and what their criteria would be for acceptance of future monitoring activities.

MR. GALLAGHER: Mr. Maynard, maybe if I could answer. This is Mike Gallagher from AmerGen. Yes, just like you said, we think that we'll show that there's more margin. Obviously, if there wasn't, we would enter that in our corrective action system and, you know, through that, the NRC would get notified and we'll take corrective action from there. We don't think that, you know, obviously we'll be there because when we credit all that metal, you know, we think we'll be demonstrating more margin.

MEMBER MAYNARD: And I would -- my feeling is that's probably true but we don't know until it's done. You answered part of it there. I want to make sure there's a hook in the system to where once it's done, the NRC would be aware if there's any issues and it could be addressed.

MR. GALLAGHER: That's correct.

MEMBER MAYNARD: Okay.

MR. ASHLEY: Mr. Gallagher brought out their corrective action program. That would be part of their current licensing basis and if there's any change that would be captured in that corrective action program which we would monitor.

MEMBER APOSTOLAKIS: Otto, this is related to what we discussed this morning. I mean, what do you mean by less margin? As long as they meet the criteria, it seems to me it's fine.

MEMBER MAYNARD: That's fine but where it effects is what -- you know, they're going to be doing monitoring. They've committed to do monitoring and they have to know at what point that they become an unsatisfactory or approaching an unsatisfactory read. So it may change their program but --

MEMBER APOSTOLAKIS: Oh, I see.

MR. SIEBER: See, the margin is built into the limit. The traditional margin beyond that limit between what they measure and what they're calling the limit.

MEMBER MAYNARD: There's also sort of a condition assessment, the way you do in a steam generator. You project ahead to the next outage and if it doesn't look like you're going to be meeting it, there's you know, some discussion that will be going on.

MEMBER MAYNARD: That's where the key is, is in projecting ahead to the next examination so providing assurance it's not going to go below the acceptance criteria.

MR. SAMADDAR: It gives you room for many areas.

MR. KUO: Yes, this is P.T. Kuo again. I just want to clarify the word "margin" and you know, the current licensing basis for this plant is to meet the ASME code, on a particular issue. Now, when we say the margin is small, that margin and really mean that over and beyond the code required margin. Okay, the code already has a factor of 2, for instance, for buckling. That already is margin. But if you have a 2.1, that .1 is additional margin. So I want to clarify that.

MEMBER APOSTOLAKIS: But when we say that the margin is eroded, we mean the .1 or the 2.1?

MR. SAMADDAR: We're talking about -- at that point we're talking about the margin over the margin.

MEMBER MAYNARD: Margin over the code limit. I just want to make sure that there is some hook in the system to where once these results come out, if it's different than expected, the appropriate reviews would be made and dealt with.

MR. HUFNAGLE: Mr. Chairman, this is John Hufnagle, Licensing Lead for AmerGen. Just a quick comment that clearly if the analysis would show that there's unacceptable margin, unacceptable thickness, let me put it that way, Potencia (phonetic) 450.72 and 73 have the regulatory hook to require that we notify the NRC and take corrective action.

MR. SIEBER: Well, it could be even more serious than that if a --

MALE PARTICIPANT: It could be 91.18.

MEMBER MAYNARD: Okay, can we go ahead?

MR. ASHLEY: If there's no additional, I'd like to go back to the introduction and give you an opportunity to ask questions about specific parts of the information that we covered during the subcommittee meeting. I'll go back to that.

MEMBER MAYNARD: Just more of an administrative thing; aging management plants, do you have what the total number was there?

MR. ASHLEY: Yes, sir.

MEMBER MAYNARD: I had a 56 and a 57 and I'm trying to sort out. You're probably going to come up with a different number now, but --

MR. ASHLEY: No, sir, at this time, I'm in violent agreement with you.

MEMBER MAYNARD: Okay.

MR. ASHLEY: It's going to be 57, 57 aging management programs, 36 existing, 21 new and those 21 new aging management programs included those new programs for the Forked River combustion turbine. And these are the systems that were included in the aging management review. The Met Tower was added to the scope which also caused the aging management programs to be added for those systems.

MEMBER MAYNARD: Okay, does anyone else have any questions for the staff on the review? Okay, thank you very much.

MR. ASHLEY: Thank you.

MEMBER MAYNARD: Now, I'd like to invite Mr. Webster up and let him introduce himself. He represents a number of entities, has an interest in the proceedings for the license renewal application for Oyster Creek. He's made presentations at the two previous subcommittee meetings and has asked for some time here and so I'll let him.

MR. WEBSTER: Hello, is this working? Once again, I'd like to thank the Commission members for allowing me to present here. I am Richard Webster.

MEMBER MAYNARD: I'm sorry, you're wired.

MR. WEBSTER: I'm Richard Webster. I'm representing a group of -- a coalition of six citizens' groups. The associate name is the Coalition to Stop the Relicensing of Oyster Creek. Now, I think I'd like to go back to the first presentation I made to the Subcommittee back in October where we agreed, I think, that we should put the horse before the cart, the horse really being the amount of margin that we have in terms of actually what we're measuring here, i.e., the amount of margin of thickness and the cart being the monitoring programs that are designed to insure that that margin is maintained.

And the propositions I put forth at that time, I think, were generally agreed on, that you need to know how much thickness margin you have to design a program to maintain those margins. You need to estimate corrosion rates, so as you were just discussing before, it's possible to project forward to the next set of monitoring to insure that there isn't a danger that it will eat through your margin before the monitoring occurs.

The problem is, as of now, we don't have that. We have a cart, we have the monitoring programs, but we don't have the horse. We don't know what the margins are in terms of thickness. And just to reiterate why that is, the main problem is the problem is really two-fold. One is that one of the criteria of the license -- put forth by the licensee or by the Applicant is that the area below .736 in each phase will be less that one square foot. The last time I put forth a graph which showed that the area below .736 in Bay 13 was around 4 square feet. I've recomputed that based on the 2006 results, and it shows that the area is now greater than 4 square feet.

So what we know is the exceptions criteria put forth by the licensee based on the GE modeling, are not longer useful because they've already gone past those acceptance criteria. I agree and what I actually asked them for, what we discussed in the letter that I wrote to you, which I hope you've had a look at, is that we agree that it may be possible to recompute those acceptance criteria using a kind of model such as the Sandia model with some modifications to reflect the latest results and to reflect certain other things that Sandia had problems with at the time.

But the licensee hasn't done that yet and so we don't know what those margins are in terms of thickness. And so I don't see how we can now decide whether the monitoring programs are adequate. How do we know that every other outage is good before we know what margin in terms of thickness exist?

Another point is that the licensee is currently using a local wall thickness criteria of .536 for the area that's less than one square foot. I think a problem with that as was brought out at the last meeting, is that that actually -- in the GE model, if you have uniform thickness of .736, with a small area of .536, that goes below code. And actually I have a memo that I received from AmerGen in ASLB discovery materials which questions the basis for this particular acceptance criteria and suggests that it isn't well justified.

And I think that's wrong. Without the finite element model showing that you can have areas thinner provided you have other areas that are thicker, that local wall thickness is not justified. So what we do know and I think the counter-factual thing in the presentations here, the applicant asserts that the measurements show that corrosion has been arrested in the Sandia. That's -- I don't think that's the case. I mean, I enclosed the statistical analysis that I received from the applicant and the statistical analysis says that there is around on average 20 mils of corrosion and the percentile range is from 12 mils at the one percentile to 29 mils at 99 percentile. So there's some thinning going on between `92 and 96.

The applicant suggests or has tried to suggest at least in the last meeting that that thinning is not due to corrosion. Well, the statistical analysis I received from the applicant, which I think it new, says that maybe there's 12 mils and that still leaves 8 mils. That seems to me the evidence of corrosion. And so I think it's premature to say the least to conclude there is no corrosion.

Where does that leave us? I think that it leaves us that we don't yet know whether the monitoring programs that are in place are accurate. They may be accurate and they may not be accurate. We don't know. We won't know until the applicant completes the finite model and may I say that the commitment today or the wordings, were extremely vague. What we know is that the other important point about the modeling is there has to be some account taken of the uncertainty of the model.

You know, if you establish that the factor of safety is 2.1, but it's plus or minus .5, that's not going to be very useful or at least it's going to give us some false reports. And so it's important to think also about the uncertainty of the model. As we see, there are a number of points measured of the drywell is relatively small. There isn't good tracking of the areas. So we really don't know what the size of the thinning walls are. At one point, where I note today AmerGen interrogated the size. Now, I've never seen -- I've had pretty much -- I've got a lot of discovery so far from AmerGen. I haven't seen anything in writing that shows that they interrogated the size using microscopes.

I have seen statements in reports that give an estimate of the size and that's only one point. But the other thin points, as far as we know, there have been on interrogation to size and it certainly hasn't been any reporting of the size. Let me remind you that I actually asked the NRC staff back in October what is the current staff estimate of the area below .736? What is the basis of that estimate and what is the uncertainty of that estimate? I'm still waiting for the answer.

I also note that AmerGen's response to my remarks last time contained no discussion whatsoever of the area below .736. So, before NRC can decide whether the proposed monitoring is adequate, it must supervise the applicant's conduct a carefully designed finite element model study. To give you an example of the details, the areas that are particularly thin have to be carefully placed and have to be reflective of reality. The Sandia model placed those areas directly under the downcomers, precisely the areas we expect them to be -- have the least effect on the results.

In reality, the Sandia areas are also smaller than they really are. So we have to have a finite element model based on reality, not based on some kind of ideologized geometries. I didn't hear any commitments for AmerGen today about how they would do their modeling, just that they're going to do something. We then need to use that finite element model not only to see whether the drywell shell is currently meeting the code requirements. We also need to figure out how much margin there is in terms of thickness at each point because if we were at the thin points it's likely that those thin areas -- if you look to the Sandia modeling, the places where it buckles in the sandbed are the thin areas. So it's likely that the margin in those thin areas is smaller than the margin in the thick areas.

I find this kind of uniform approach averaging over the whole bed, I don't think it's going to work because in reality we're already below that .736 in significant areas. And so what this all means is there's a lot of work to be done before we can decide whether this license renewal application should be approved. We think that this committee has played an extremely useful role to date, has really held the applicant's feet to the fire in terms of making sure their analysis are technically justified. We would like that role to continue and we feel that role is an essential role. It's a role that we would hope would be played by NRC staff but I think it's been clear that this committee exerts a degree a rigor that the staff doesn't always exert.

We, therefore, appeal to this committee to wait, wait until you actually see the analysis to make sure that what's proposed is really going to work. Now, just to finish up, we're not the only people who think that. The State of New Jersey has also written to you suggesting that that is the appropriate course and a number of representatives, elected representatives from New Jersey have also written to you suggesting that would be an appropriate course. So we appeal to you, please make sure this is adequate. I don't think you're in a position to do that today, you may be in a position to do that when AmerGen actually puts forth the scope of work, the scope of work is agreed, the scope of work has been done, the margins have been established, and then the margins can be compared with the monitoring programs and we can see whether the whole thing makes sense.

I thank you for your time, if you have any questions.

MEMBER MAYNARD: Anyone have any questions for Mr. Webster?

CHAIRMAN SHACK: I don't seem to have a copy of his letter. Is it somewhere on the table?

MEMBER MAYNARD: Is it on the table there? If not, we'll make sure that you get it. There was a copy made for everyone.

MEMBER BONACA: In the attachment to the letter there is an analysis by Mr. George Licina. Can you tell us a little bit about how this came about?

MR. WEBSTER: Yes, this is discovery. We are in a proceeding, an Atomic Safety and Licensing Board proceeding, where we're contending actually that the frequency of the monitoring is insufficient to maintain the margins. As part of that proceeding, we are -- both parties are required to exchange relevant documents under a process called mandatory disclosure. And this is a document that we received from the licensee, from the Applicant as part of their mandatory disclosure. So this is not our analysis.

MEMBER BONACA: This is their own analysis.

MR. WEBSTER: This is their own analysis.

MEMBER BONACA: And do you know who -- maybe the licensee should answer, who is George Licina?

MEMBER MAYNARD: I'd like to ask a question regarding --

MR. GALLAGHER: Excuse me, Dr. Bonaca, did you have a question about the --

MEMBER BONACA: I just wanted to know, did you commission this study and who is Mr. George Licina?

MR. GALLAGHER: Which study are you referring to?

MEMBER BONACA: This attachment to the letter which apparently is -- comes from the licensee.

MR. GALLAGHER: Oh, okay, that particular study?

MEMBER BONACA: Yes.

MR. GALLAGHER: Yes, I can explain that and that study is a draft study to look at if there was any possible statistical analysis that would indicate corrosion in looking at the individual points that were taken externally in the same bed. That analysis is draft and there was a subsequent analysis that was completed in January. And I assume that analysis has not been discovered by Mr. Webster yet through the legal process. So that analysis concludes that there is no corrosion, corrosion is nil and the difference is explained by the technique difference which we explained to the subcommittee, for the UT data that was taken in 2006 versus 1992.

So what we have said is, the 2006 data is baseline. And because of the difference in technique we used, because of the -- we had to shoot through the coating externally from the sand bed and verify that we got the inaccurate measurement. So short story is that, you know, when you pick an isolated document from our record without understanding what's going on, there's more information available.

MEMBER BONACA: So did a subsequent study -- did the same person, Mr. Licina do the subsequent study or --

MR. GALLAGHER: That's correct, Mr. Licina.

MEMBER APOSTOLAKIS: Who is he? We didn't get the answer to that?

MEMBER BONACA: Yes, who is he? Is he --

MR. GALLAGHER: Mr. Licina is a consultant we have and he works for Structural Integrity.

MEMBER MAYNARD: Okay, are there any other questions?

MEMBER ARMIJO: Well, I would just like to make a point. Independently, I did something very similar to what Mr. Licina did and, you know, I saw the same phenomena and my conclusion was that -- and I think you're trying to or you've concluded that based on those measurements, there is some indication of a continuing corrosion even after the coating was applied. I looked at those data very carefully and there is -- for each period of time, all the data are very consistent for that particular period but they're different from the previous period. So there are systematic changes, systematic bias and there was no way that I could conclude that there was continuing corrosion, that the most reasonable interpretation of the data is that the corrosion had been arrested since 1992 by picking the minimum corrosion which would be the more conservative way to go.

So the apparent -- after you've gotten to a minimum wall thickness at the same point, it won't get thicker with time from corrosion, it usually gets thinner. So I think it's just systematic error in the individual measurements each year and so I saw the same phenomena that Licina saw and I believe he didn't interpret it that it was continuing corrosion, and I certainly didn't. So I think there's a reasonable interpretation that supports the visual examination that we saw in the photographs.

MR. WEBSTER: Well, I mean, what I'm saying is at the moment, I think there isn't really enough data to pick exactly what's happened. I mean, I think the conclusion that there is no corrosion is perhaps a little premature. We'd have to wait till 2008 to really confirm that if we use the same technique. But I think the important thing is, that even if there is no ongoing corrosion, the wall is definitely thinner than we thought is was in 1992.

And this is the second time we've seen the example of a systematic bias upwards in the results. We saw a systematic bias in the 1996 results and we saw a systematic bias in the 1992 results from the outside is what we're saying now. And these biases are not small. I mean, we're talking a margin here -- I mean, a couple of interesting things. One is that they have contained the margin at .064 prior to this last round of monitoring. Having observed the wall thickness reduction of around .02, there's still time to say a margin of .064. I think that's problematic. I mean, there does seem to be some disagreement between the different areas but the key thing with these exterior measurements is they're not properly factored in to the acceptance criteria.

For these measurements, they're using the small area thickness of .536, which, as I said before, is not properly justified. And they don't even measure whether it is or isn't the small area. And so they're measuring grids a quarter of a square foot and then applying the sections criteria of .736 for that. They're making single points which may be representative areas of greater than quarter of a square foot where they're applying a criteria of .536. It's inconsistent.

MEMBER MAYNARD: We are running a little low on time. Any other questions for --

MEMBER APOSTOLAKIS: Yes, I'd like to know what the NRC staff thinks about Mr. Webster's position. Is it an appropriate time to ask? I mean, the way I understand you is you don't believe that the appropriate studies have been done to determine the margin.

MR. WEBSTER: That's right.

MEMBER APOSTOLAKIS: So what is the staff's position?

MEMBER MAYNARD: We can ask them. I think they've stated it before but --

MEMBER APOSTOLAKIS: Well, we can ask them again.

MS. LUND: We've got all the correspondences that Mr. Webster has provided to us and the technical staff is working on responding to them. In fact, Sujit had told me that it would be -- probably he would have the response to us in about a week or so, so we will be responding, you know, by a letter to Mr. Webster, but I wouldn't say that -- on a number of these, I think that we -- like some of the things that have been presented today, we're looking at them very carefully and I anticipate that we'll be able to support what we've already presented in our safety evaluation.

MEMBER BONACA: The licensee has agreed to perform a finite element analysis and submit it to you for review. So do we have any idea what the committed date is and I'm sure you're planning to review that analysis. That would establish the current condition.

MR. HILAND: Yes, this is Pat Hiland, I'm the Director of Engineer. The applicant has not conveyed a date when they would have their finite element analysis completed so I cannot answer the question.

MEMBER MAYNARD: The way I read the commitment, what they put up on the board was it would be done prior to the time of operations.

MS. LUND: Right, this is Louise Lund. Yes, that's right. It would be prior to the period of extended operation.

MEMBER MAYNARD: Okay, any other --

MEMBER BONACA: That means, however, that you're only viewing that analysis in terms of the renewal rather than the current licensing basis. I mean, if you had a concern, that it won't meet criteria --

MR. HILAND: That's correct.

MEMBER BONACA: -- you're going to question a review analysis now.

MR. HILAND: That's correct.

MEMBER BONACA: Okay.

MEMBER MAYNARD: Okay, I'd like to say

that through all of our subcommittee meetings and this one, I appreciate everyone's input. I think the presentation has been very helpful. I know that Mr. Webster's comments provided me additional things to look at in the past there in taking a look at this data and everything. I found the comments very useful in my review. For those who haven't seen the letter yet, we will certainly make sure you have a copy of that letter with his points in it there.

So with that, I'd like to turn it back over to you, Mr. Chairman.

CHAIRMAN SHACK: That's fine. I think we're ready to take a break for a half an hour.

(A brief recess was taken at 3:38 p.m.)

(On the record at 4:18 p.m.)

CHAIRMAN SHACK: Can we come back into session? Our next discussion is the development of the TRACE Thermal-Hydraulic Code and we'll be led through that by our cognizant member Sanjoy Banerjee.

MEMBER BANERJEE: So I think this follows up from our subcommittee meeting and Steve Bajorek, I guess, will be telling us about various activities. Now, Steve, a couple of things; if you would try to focus more on TRACE itself and maybe less on pi groups and things like that.

MR. BAJOREK: Yes, is this on? Are we going to be okay? Yes, I'm ready to talk about all three of the things that we talked to the subcommittee on December 5th about the bulk of what I'm going to talk about today is on TRACE and some of the issues surrounding that. Some of the material I have at the end, I'm going to talk about pi groups and the -- e may not even have time to get to that.

MEMBER BANERJEE: Right.

MR. BAJOREK: So the main things that I do want to talk about today are the issues that we talked to the subcommittee about on December the 5th. I'll leave the pi groups and the anonymous letter go to the very end and spend most of the time talking about TRACE, where we're at, brief you on a status of the TRACE code and development, assessment that we've been performing, where we're at with the documentation. That was an issue that we spent a lot of time talking about on December the 5th, talk a little bit about our Get Well Plan, how we intend to finish the documentation, some changes that we've made over the last several weeks to it, and how we're going to proceed over the next several months.

I don't know, of interest to us and I think it's been brought up by this committee is, are we going to integrate TRACE into the regulatory process. We've been developing this over the last several years it's been scheduled as well, but now is the time when we need to start using TRACE as an agency tool to look at uprates. We've used it for new reactors. We've used it for other issues and we actually have used TRACE for several problems where it was applicable at this time. But how do we support that role of getting TRACE into very widespread use by users throughout the Agency?

A little bit of the history and here I want to start off at the bottom with what we think is a major milestone. The end of December, we released a code called Version 5.0 internally to the staff, to NLRI and to other people within the Agency. At that time what we said, we are freezing the code. We have stopped model development. We have gone through the last round of major revisions to the code. We have run through all of our assessment cases. I'm going to talk a little bit about those and what that entails and we felt at this point, we're ready to put the code out there, get more widespread use, because as you start to get more use of the code, that's when you do find what other features you might want to improve on, what other errors or problems you see but we can't continue to develop the code forever. We thought this is the time.

We froze it, we put it out there and now we're going to start moving more towards finishing the documentation and into the support maintenance role.

MEMBER ABDEL-KHALIK: Excuse me, do you have an adequate user's manual that allows people to actually use the code?

MR. BAJOREK: Yes, the user's guide for TRACE has been continually updated. As we put new inputs into the code, we change things, that user guide is changed along with each version that comes along. But when we get to TRACE 5.0, through its history over the last couple of years, this is a numbering system that keeps track of the various updates but as that update necessitates a change to input or requirements that the user would have to do, those are -- those changes are made in the user guide and that pdf file is also released along with the code. So for somebody who wants to set up a model to use the code, they have an up to date user's guide. They have decks which are available, hopefully fairly close to their application and between that and the existing information they have, they should be able to proceed and do their evaluation.

Now --

CHAIRMAN SHACK: Is there somebody responsible for support to help people, the users?

MR. BAJOREK: Yes, that's our Code Development Branch. Rich Burton is the Branch Chief for that. He's got a staff that has been growing. It's gone from on the order of five or six people to something like 10 or 12. Over the last several years there have been a couple of people dedicated not quite full time to maintenance and updating the user guide but keeping track of those updates and revisions as they come in, maintain the data base of the decks, things, as those come back into us and other people, you know, revising, fixing the models and making the corrections.

As that staff has grown, we think now we're in a much better position not only to do the maintenance but to finish the other documentation, complete the other assessments and start moving on to the support role of running plant calculations and looking at the problems that can be experienced when you do these type of calculations.

MR. SIEBER: Steve, do you believe that the errors have all been corrected?

MALE PARTICIPANT: Don't answer that

question.

MALE PARTICIPANT: On the grounds it may incriminate you.

MEMBER CORRANDINI: So, can I ask a different question that leads up to that? At the subcommittee meeting that Sanjoy ran in December we were able to look at this ahead of time. Is this the current version -- if somebody said to you, "Here it is all on one CD," is this it?

MR. BAJOREK: The CD would contain all of the documentation. On that one you have the latest version of the code, whatever it was in the early part of December or November when that was put together, the user guide that is consistent with it, and all available information for the theory manual and the assessment manual, I believe, was also no that at the time. Now, because the code was changing at that time, those assessments were probably three or four months out of date. The theory manual would be roughly 75 percent complete. And unfortunately, the parts that are of most interest to a lot of users, the closure model, that's out of date. We're changing the field equations to make them better structured and more descriptive. That section has been changed, but the parts that talk about the reactive cooling pump, that's some of the fuel rod models, that has not been changed dramatically, so it would be of use for things like that.

Just a brief history of where TRACE has gone leading up to what we are working on presently; is the consolidation project started in about 1998 when the staff realized that maintaining TRAC-P or TRAC-B a RELAP and a RAMONA all with overlapping capabilities was very expensive. You almost had to have a staff for each one of these. Because those capabilities overlapped, it made sense to try to consolidate all the features into one platform, update that, modernize its architecture and make it easier for one smaller staff to make changes and maintain that code.

Most of that work took place in about 1999 to about 2003 and shortly after that, we started to do some of our initial assessments. And that's when we started to realize that the mission that we were undertaking had to change. We thought at the start that the TRAC-PF1, Mod 2 models were adequate and had been assessed. In actuality, when we started to go through some of those initial assessments, we had cases that wouldn't run and were so far off in the data, we did not feel that we could release a code that would be considered reasonable and acceptable in that timeframe.

Our internal criteria at that time and that's kind of continued, is that we weren't going to release TRACE if the results, the comparisons between predictions and experiments, were unreasonable. And by unreasonable, we mean, it needs to predict trends, it needed to be in the bounds of experimental uncertainty for much of the time.

MEMBER BANERJEE: Let me ask you a question, Steve. You have a Code RELAP 5, various versions of it, which are now being used by NRR for confirmatory analysis. In fact, today we heard about calculations done using it. Now, there are two issues here. One is if the models are wrong, shouldn't we be getting a code with better models into widespread use immediately rather than waiting around? Shouldn't this be a very high priority activity?

MR. BAJOREK: Well, yes, and I believe it is. I mean, we want to make sure that the models in this code are adequate to do the types of audit calculations that we're faced with, the conventional plants and advanced plants like ESBWR, 8/1000 or -- you know, we think TRACE is there and our -- one of the reasons we're very much convinced of that is the assessment matrix and the assessment matrix that we put this frozen code through -- I'm jumping ahead a little but when we look at the assessment matrix and the mission that TRACE has to fulfill in doing flume water reactors, pressure water reactors, and the advanced reactors for both large break and small break, our assessment matrix has grown to roughly 550 individual simulations.

We run through all of those and we're convinced that for the most part, it's doing a credible job. There will always be cases we're not happy with.

MEMBER BANERJEE: So if you're taking the correlations that existed in RELAP 5, and just put the in, the code wouldn't do nearly as well.

MR. BAJOREK: I think that's an open question because if we take a look at what RELAP's assessment base is, and how you assess RELAP 3.2, 3.3 and some of the -- their assessment matrix is on the order of 30 cases. It doesn't go anywhere near the breadth that we are putting with TRACE.

MEMBER BANERJEE: I'm just asking if you just took those correlations and put them in and didn't take all this time doing this, what would -- I mean, why didn't you follow that strategy to start with?

MR. BAJOREK: The decision had been made, you know, back in 1998, it was well before I was here that TRAC TF-1 was going to be the best means of going forward.

MEMBER BANERJEE: Sure, but what about the correlations. I mean, you spent a lot of time you know, inventing your own correlations or putting them in or choosing -- assessing correlations. Why didn't you simply take those in RELAP 5 and put them in as a starter?

MR. BAJOREK: I imagine that could have been done but usually in these types of codes, you almost have to look at these as model packages. You know, it's not simply taking a correlation for one particular phenomena and dropping it in because you think it's better. But it's how it works in conjunction with the other correlations that give it a flow boiling map for example, or how they transition one flow pattern to the other. So even though if you go through and they say, "Hey, this might be the best correlation", and the put it in another code, you may not necessarily get better results.

MEMBER BANERJEE: I'm talking about the whole package.

MR. BAJOREK: Well, that could have been done. The decision to go with PF-1 was made based on the idea that the development that had been going on in the `90s, had actually improved those thermal hydraulic models at the time.

MEMBER CORRANDINI: Sanjoy is way ahead of us in terms of the background. So the basis for this is not the same hydrodynamic basis as you have in the previous codes. What is the basis? Did it start from scratch or did you start with a basic hydronamics package?

MR. BAJOREK: That was started from scratch PF-1 Mod 2.

MEMBER CORRANDINI: Okay. And then so pretending this is almost like an experiment, just a numerical experiment, what I think he's trying to get at is how did you, as you went along QA it to know of it, you could at least reproduce, whether it's right or wrong, but replicate the previous results so you knew you were always -- you knew when you branched to another result, you knew what was going on? Was that done throughout the QA'ing process?

MR. BAJOREK: It started in about 2003 close to the end of the consolidation. The assessment matrix then was based primarily on cases that had been used for both RELAP, TRAC-B and TRAC-F. We would run all three codes or all four of them because they were available, look at the results and insure that TRACE or TRAC-M as it was called back then, was giving results that was consistent with RELAP TRAC-B or TRAC-P.

MEMBER BANERJEE: What I'm really wondering is why it took you five years to get there.

MR. BAJOREK: It's a slow process.

MEMBER BANERJEE: It sure is.

MR. BAJOREK: There's a limited amount of resources that you can put on this.

MEMBER POWERS: Steve, let me ask you a question. How many lines of code, roughly, th order of magnitude?

MR. BAJOREK: I think it's on the order of 250,000 lines.

MEMBER POWERS: And the difficulty of changing a line of code goes as about the lines about the third power or something like that, at least.

MR. BAJOREK: When you make a change, you often have to make that change in several parts of the code. That was one of the reasons why the modularity was put into the code to make this easier because we wanted to get to the point a couple of years ago that as we started to get better and started to get more information available from the tests we were running, to make it actually easier to implement those and go forward. I think part of the basis for picking TRAC-PF1 versus RELAP is in working in both of those codes, I don't think either one were really considered truly state of the art in that they had the very best models available.

So it was a matter of picking one, picking an architecture that they thought at the time would be the most efficient to move forward with and marching ahead with that one. Now, since then, you know, some models have been changed, some of those are models that are closer to RELAP, taking those when it's been convenient and convinced that those are better models and put those into TRACE. But another aspect of, you know, why this is taking so long is that time frame 2002 to 2004 was also when we started to -- we were actually doing the design certification AP-1000, ESPWR was starting at that time, ACR-700. A lot of our staff was being diverted to develop condensation models appropriate for drywell and PCC HX's in ESPWR.

We developed a horizontal fuel bundle model and started the assessment against RD-14 and RD-14L. Now, by the time we got those models ready and it started to get kind of exciting, that's when the ACR-700, that application went away, but the Commission's direction to us in that time frame was to get things ready and prepared for doing the advanced plan. We knew we had to spend some time on that.

We've also had some other -- you know, a couple of other activities, supporting 50.46(a). We used TRACE for the emergency diesel generators to show that 10 seconds wasn't exactly a hard and fast number and there could be some relaxation with that. And we looked at some station blackout questions for Region 1 last year. But the real --

MEMBER CORRANDINI: If I may, so the answer to my question is, I just wonder, so basically TRACE came from TRAC-M and as you're now using TRACE, you're continually going back and cross-comparing with TRAC-P and TRAC-B.

MR. BAJOREK: Yes, back when we developed TRAC-M, we're looking at TRAC-B, TRAC-P and RELAP, convince ourselves, that hey, we were getting about the same results as we had been getting before for a very limited assessment base. But we also took a look at some of those cases and we started to find things that we couldn't live with, calculations with TRAC-M for this a forced reflow tests, a relatively simple case but totally grossly over-predicting some of the elevations. And you say, "Well, so what, we have to be conservative". Well, not -- it wasn't conservative everywhere. There were compensating errors in the way the code was doing the interface of heat transfer, that some elevations were overheating. You were over--cooling the upper elevations. We couldn't live with those results.

MEMBER CORRANDINI: If I might just ask a question here; so that means that if you were to have run TRAC-P and TRAC-B, you would have gotten the same result?

MR. BAJOREK: If we were running this test, not all those codes were run against some of these tests. So in some cases you have a TRAC-P result, in others you wouldn't. I think TRAC-P in this case was also -- was giving us similar results because there were the numerics and closure models of TRAC-M were basically the same as TRAC-PF1, TRAC-B. So we were seeing about the same thing. One of the problems is when they developed TRAC-PF-1, Mod 2, they did a lot of work developing the code, but there's almost no assessment. So many of the things that we're finding for TRAC-M also apply for TRAC-B. They hadn't been discovered in the time frame of the `90s when you would have if you had been developing an assessment process to shake down the code very quickly.

MEMBER BANERJEE: Now, TRAC was never really a code for small breaks. Presumably, TRACE will do that. So we have a lot to do on that.

MR. BAJOREK: If you look at a couple of cases where we did go ahead and use a version of TRACE, it was for small break applications. We've been finding that the results for small break tend to be a little bit better than they are for some of the large break phenomena or they had been for some of the reflect phenomena. So we're finding through the assessment we think it's doing a --

MEMBER BANERJEE: Is it doing --

MR. BAJOREK: Is this okay?

MEMBER BANERJEE: So TRACE is now working for small breaks and large breaks.

MR. BAJOREK: And large breaks.

MEMBER BANERJEE: And for BWRs?

MR. BAJOREK: And for BWRs.

CHAIRMAN SHACK: It's working well, right?

MR. BAJOREK: Yes.

MEMBER BANERJEE: Well, it's operative.

MR. BAJOREK: We think it's working well.

When you consider the breadth over which it's now being exercised and I mentioned we're using this over some 500 assessment cases. Okay. Other codes, RELAP had been exercised with assessment basis on the order of 30 or 40. Well, if you take that number and you increase it in order of magnitude like that, you're going to find some problems. Okay, we've exercised the code and yes, we found them, okay. We're fixing them.

So I'm going to -- in the interest of time, jump through this. So in the way we have been working, after we've defined the process that we have to get right boiling water reactors, pressurized water reactors, advanced reactors uses approach methods, developed for those, we've established the assessment matrix. We have thought that the models in TRACE would be acceptable. We run through the assessment matrix. When we get down to here, if we get a yes, we're good and we document. That's where we're at now. Unfortunately, when we ran a lot of those over the last couple or three years, we found models that were deficient. We went back and looked at the model development process. In some cases, it was a matter of looking at the model, replacing that correlation with something that we thought was better. In some cases we went back to the some of the newer experimental tests that we have to look at pebble breakup in suppression pools and some of the condensation tests that have at pooling to help us with the PCC ES heat exchanger.

Put those models back into TRACE and when everything is becoming what we considered reasonable and acceptable, now we're down and ready to really document the results and release it for applications.

MEMBER BANERJEE: It's working also for the containment part?

MR. BAJOREK: TRACE is the hydraulic code that is meant for the primary system. For containment we have linked it with the contained code in order to get a feedback between TRACE and what goes on in containment. That's how we would do it in a PWR. Now for ESBWR, at this time, we're trying to do the entire primary plus the drywell and the containment systems with TRACE. That was the reason for improving the condensation models for drywell condensation in the presence of non-condensibles.

MEMBER BANERJEE: So you have compared the PANDA and so on.

MR. BAJOREK: Yes, yes. I'm going to talk about those cases. Okay, I think we've covered -- in correcting the models, the closure relations that now have been replaced on the order of about 75 percent. We've replaced the reflood model and its package which represents some 50 different correlations for interfacial drag, wall drag, the various transfer regimes. Joe Kelly talked about the condensation models he was developing for ESPWR. He talked about from the thermal hydraulic side he came here about a year and a half or two years ago describing what those were.

In correcting those, we had to make changes to the wall drag in order to perform thickness and get that resistance to heat transfer correct, change the interfacial heat transfer because in a number of these integral effects tests, we were finding that excessive condensation was causing undo oscillations and that was causing core hydraulics to go bad on us. So that was corrected.

And interfacial drag, in order to get levels for our calculations correct, in models like THTF, RDHT, so those were behaving correctly at both high pressure that attract the effluent in real life, should do a reasonable job but also at low pressure which is much more challenging in these codes and what we needed for something like ESPWR and AD-1000 to pass the plants that --

MEMBER BANERJEE: So will you be able to handle EPR?

MR. BAJOREK: Yes, with some additional checking and validation on some of the features of EPR that really aren't tested in some of the other assessments.

MEMBER BANERJEE: But in particular the refluxing.

MR. BAJOREK: That's one we have to look very carefully at.

MEMBER BANERJEE: But you're not sure of that yet.

MR. BAJOREK: Right now, no, we're doing the assessments right now. The models are there. They should work but we're going to go that extra step and comparing against three different types of reflux condensation tests in order to make sure those models are doing the right things for the right reasons.

So ask me that question maybe six months to a year from now, we'll be able to know that for sure. But anyway, as we've gone through the assessment, then, we run the initial steps of assessment tests. We've expanded on that and we've looked at those tests in much greater detail than we had in the past or we had in the predecessor code. We didn't just focus on peak cladding temperature, but as we went through and we would look at a forced reflooding experiment, we would look at cladding temperatures, okay. The code is in red, the data of the thermocouples in black in this case.

We would look at heat transfer coefficients at multiple elevations and we would look at quench profiles. We would look at the bundle mass in there and for us to say that simulation was reasonable, we had to get simultaneous agreement in a number of these parameters that might be interpreted as a figure of merit. Now, you look at these, yes, there are still some problems. There are places where we heat up degrees, there's other where we under-predict it, but as we look at all of the tests in aggregate, we think that the code is doing a reasonable job. Some are over-predicted, some are under-predicted and then if we looked at the overall bias, it's not too bad.

MEMBER BANERJEE: The red in the case is your --

MALE PARTICIPANT: Prediction.

MEMBER BANERJEE: -- prediction.

MR. BAJOREK: Yes, the prediction and the black shows the thermal couples.

MEMBER BANERJEE: That slide is completely unreadable.

MR. BAJOREK: Well, I put them all on separate slides and I don't want to be here too long. The point I want to make is, we don't just look at cladding temperature. We look at multiple elevations and we try to assure ourselves that the model is being written correctly throughout the entire facility.

CHAIRMAN SHACK: Now, how are you doing on run times?

MR. BAJOREK: In some cases, not too bad. The separate effects test and we took a whole battery of those and those ran out. When you start to run some of the integral tests, we've got a couple of bad actors. For some reason CCTF and SCTF, there is condensation interaction between the cold layer and the downcomer slows that down and we're looking at that. Some of the ESBWR-specific tests at low pressure are also giving us some fits. We're looking at those from the speed goes up.

MEMBER CORRANDINI: If I might as, is there a generic reason why they're slow? Is it the interfacial condensation transfer coefficient?

MR. BAJOREK: I don't know because with

many of these things, particularly in a condensation mode you get this -- you get this flip-flopping of the interfacially transfer coefficient. Sometimes you're evaporating, sometimes you're condensing and the interface doesn't know where to go. So the code essentially goes into a total meltdown.

I think it's a variety of reasons. A lot of them, and this is me talking, I think are often condensation related. When we get some of these processes where we're getting into very large, you know, interfacially transfer coefficients, the code changes and you gets some of these velocities that feed on that.

MEMBER CORRANDINI: If I might ask one other thing, just a detail, I apologize? So is there some sort of task manager that you can tell the sub-routine where all the calculations are being held up? Usually with these large hydro-codes there's a task manager.

MR. BAJOREK: There is in TRACE? Chris, how well does that work?

MR. MURRAY: Hi, this is Chris Murray. I'm that Code Caretaker for TRACE. The code does have diagnostics that point you in the right place. If the code gets into trouble in a time step, it will point to the component, you know, the time step that is having problems so the code does have those diagnostics that help a user to home in on that.

MEMBER CORRANDINI: But as you discussed it, there are certain things that are causing you problems, there's no generic issue that pops up?

MR. BAJOREK: I don't think there's any one generic issue. I guess one part of my head, in answer that question, the code had the diagnostics to look at that but a lot of times when you look at these very large systems models, the code starts to complain, not necessarily in the place that is causing the problem, but it's the weakest link in the model where the velocity has been exaggerated and the pressure drops are exaggerated. So, you just have to look deeper into the coding in order to find what this is.

MEMBER MAYNARD: A quick question on your previous slide; the biases were the code may be a little higher. Let's take cladding temperature where it predicts high. Is it always in the same area to where you can use that or is it -- that could be some times over further to the right, or -- I'm just wondering if even though there is a bias, if it's always in the same area, same types of situations that you can factor that in for your evaluation.

MR. BAJOREK: Yes, when I look at a group of tests, I think we're getting closer to the point where we can start to isolate, yes. The forced reflood test rate is, for example, they tend to overheat at the upper elevations and we traced that back to the lack of a spacer drop and breakup model that would bring down the steam temperatures. So we're -- sometimes when we see the code doing what we don't like, the wrong thing, we can trace that back to certain models, and things that, yes, in later versions that we know are correct.

MEMBER KRESS: That assessment for Test 31805, the other one you had was 31504. What would it do, how would it do on this one?

MR. BAJOREK: About the same because they're about the same thing.

MEMBER KRESS: It would come back down to about --

MR. BAJOREK: Yes, 31805 and 31504 is like one/eighth of a second versus .8 of an inch a second, very close. These were the results I had.

MEMBER BANERJEE: So will we be able to see confirmatory analysis for ESBWR with TRACE?

MR. BAJOREK: Yes.

MEMBER BANERJEE: You told me that you're having -- told us that you're having problems with stability and time step and --

MR. BAJOREK: Well, we're getting the cases run out. I think Dr. Shack's question on run time, we're getting them through, sometimes in fits and starts and sometimes these calculations are taking a couple -- several days, where we want to try and move that. So in time, yes, we'll get those calculations done but it doesn't necessarily mean it's easy all the time. But I'll talk about the ESBWR in the report that we're preparing in a little bit.

A couple of comments on the overall assessment matrix; as I mentioned, we went through and we looked at parts for pressurized water reactors, boiling water reactors, large breaks, small breaks, to identify all the phenomena that we needed to get correct in this code. So our target hit list is composed of things like break flow, ECC bypass, reflood, heat transfer, level swell, all of those things that experts have indicated we've got to get right in a large or a small break LOCA.

The assessment group is divided, overall into four different areas and we're on the order of about 550 individual simulations. The number of assessment fundamental cases, these are single tube tests, U-tube manometers (phonetic), things that you got to get right before you can really move on.

CHAIRMAN SHACK: An elbow.

MR. BAJOREK: An elbow, she's a single here to quantify measure and quantity or you could sit down with a textbook and you can calculate what you should get.

Then we moved onto, of course, separate effects tests to look at things like reflood, heat transfer, level swell. Integral effects tests covered both large and small break and then a number of ESBWR specific tests, PUMA, PANDA, GIRAFFE, Ontario Hydro, a number of tests that you need to get right to work out behavior in chimneys, behavior in the drywall, overall system behavior in a passive BWR. If we look at these first three categories that really perform the generic fundamental basis for the code, it's consistent with CSNI recommendations on what types of things you should be comparing against in order to assess your code and we feel that it's sufficient for a CSAU-type of application. CSAU code scale on applicability and uncertainty is the method by which you would take the code and apply it to a full-scale plan and have some confidence that the things you were doing an assessment of these sub-scale cases really apply to the full scale plan.

Now, to do that, you can't rely on one assessment of a reflood test or one ECC bypass test but you need a sufficient number on which you can develop a bias and uncertainty. So we've taken this assessment matrix and instead of just leaving at the cases that they had done historically for RELAP, TRAC-P and TRAC-B, we've expanded that so that if we take a particular phenomena that's highly ranked, we have enough information that we can go back, characterize the accuracy of the code and eventually determine a bias and uncertainty that we can use in plant on certain evaluations.

This one -- I use this by example, is it shows us how we're doing for ECC bypass by comparison. I think a couple of the vendors also use this for their large break. I did this when I was developing another code. We used five tests. The original assessment for TRAC-PF-1 used one. We have a total of, I think there's 15 or 16 different cases on there. So I think that what we have actually done with our assessment matrix, we've fulfilled the obligation of a CSNI for assessment, we're able to characterize these individual phenomena and we've developed now enough information to go into biases and uncertainties and go that next step in code development when it comes to developing an uncertainty methodology.

MEMBER POWERS: Steve, a lot of what's gotten discussed today and in other context with TRACE has been about how does it compare to RELAP, et cetera, et cetera, et cetera, how does it compare with your older versions of TRAC and things like that. I know that there is another code, thermal-hydraulics code out there in the world that at least the developers seem to be very proud of called CATHAR and that's under continuing development, as I understand it. How do you -- what do you do with that group or that code? Do you compare yourself against them? Do you look at what they've got or --

MR. BAJOREK: Yes, actually, some models and correlations which are in TRACE right now, the level swell, is very close to the model that's in CATHAR. We're aware of what they -- you know, that code, with their publications and the information and you know, and the number of cases. We've actually pushed some of our models to be more like CATHAR's than the RELAP or the previous other TRACE that's been out there.

MR. BAJOREK: So we're --

MEMBER POWERS: Maybe when you come to your conclusion you can talk to me a little bit about this. Okay, you've got CATHAR, am I saying that right?

MR. BAJOREK: CATHAR.

MEMBER POWERS: And you've got TRACE, doing the same -- roughly the same job or the same job or -- there may be more people, I mean, we're all biased and you have to have --

MR. BAJOREK: Yes.

MEMBER POWERS: Okay, fair enough. There are two of them going along. Is that a forever situation or should there eventually be just one code?

MR. BAJOREK: Actually, I'd kind of like to see different codes. There's been a couple of international exercises where the same users for the same code, different codes, and have them go off and do the same problem. And it's kind of surprising to see what differences you get. In AP-1000, I think some of the more useful review information was obtained when we had two different -- we had two different codes predicting the same thing and one went up, the other went down. We really had to delve into what was the reasons for that and were they real. And I think as we explore that because of the differences in the code we learned a little bit more about the plant, the system behavior.

MEMBER BANERJEE: I think Dana has a good point here because CATHAR certainly has a very significant development effort ongoing, plus it's plugging into a framework where you're going to have multi-dimensional effects and all these things taken into account which are the things that Professor Wallace, of course, always brings up, why you're trying to do multi-dimensional problem with a 1-D code which doesn't make any sense, and therefore, you're always get into a position where you're defending something that is indefensible. Okay, and CATHAR doesn't try to do that.

They try to do multi-dimensional things where multi-dimensional is important and 1-D where 1-D is important. And they're part of a much larger program which is taking into account all these factors whereas you are not. You know, you're trying to do something which you can't do in some way. I mean, you can do part of the job, but you can't do the whole job, obviously. So, I mean, it's not -- this is a remark certainly worth looking at.

MR. BAJOREK: I think the development team would welcome more interaction with groups like those working on CATHAR, those working on the MARS code in Korea, who are also looking at similar types of codes and applications. You know, our mission is to develop a code with the resources we have available at hand.

Now, the real problem area in our effort has been in the documentation. We have been so much -- spent so much time in trying to get the code to run, get the code released, perform the assessments that documentation and documentation primarily being a theory manual and information that supports that has lagged behind. But with the release of TRACE in December, the development team is not switching its focus and the documentation is becoming its highest priority.

The documents that we expect to have here in near term, of course, the user's guide that's consistent with the executable, that's already available. We've actually run through all of the cases with the frozen code but now what we are asking our analysts to do is to run this again, run it on a Windows platform, run it on a Linux platform dependencies, make sure that those don't exist. Look at the results and draft a report that's already prepared and make sure that the text and the information and the numbers and description of that transient is consistent with the changes that may have crept in with these last couple of versions.

We don't think they're large, but you do risk the chance were your prediction instead of over-predicting the pressure now slightly under-predicts it. You need to make sure you get the wording correct.

We expect to have that report available by the end of April of this year. The theory manual, probably in about June, this is our expectation. There's two things which are -- which kind of make this a little bit longer to produce. We have taken the comments that we got in the December 5th meeting to heart. We've taken the field equations section which rely on a lot of references on why we're doing things and change that section to be more systematic in going from the conservation equations, the assumptions you make to make them in finite difference form and then the review the limitations and problems that you invite when you go from the original form to make those approximations fit into a discrete notalization. Closure models, because there is so much new information, that is probably our critical path and one of the last chapters that will be completed. But we think we're going to wrap all of that up in about

June of this year.

We're going to have another volume that we're calling the Volume 2 or the Theory Manual Supplement. If you're a user, you want to know what's in toe, what coloration am I using, what break flow model, what number flow model you're using. You want to go to the theory manual. It's going to describe it. It's going to tell what's in the code. It's going to tell what RAMPs and other transitions might be impacting it. If you want to understand why that particular correlation was selected, what it has that makes it unique from all of the different choices, there are theory manual supplements that are going to go more into those types of details.

We wanted to get something out quickly that users could use and go back and help them diagnose their problems and have something else that's of more use to reviewers, code developers and code programmers. That's going to be a couple of months behind.

Now, ESBWR, those cases, the PUMA, the PANDA, GIRAFFE, other cases, these often involve proprietary information. We wanted to have the theory manual and our assessment report be generic and also widely disseminated without worrying about proprietary information. So because of that, we're putting together what we're calling an ESPWR applicability report that will both look at the system, look at the tests which are being used, look at the scaling of those facilities to the ESPWP plan as it's changed over the last several years, the assessments that go into that and then some information on how you should be using TRACE to analyze the ESPWR and the projected date for that is in November.

MEMBER POWERS: Steve, if I as a citizen in the United States called you up and said, "Gee, I'd like to get ahold of TRACE", what do you tell me?

MR. BAJOREK: I would say you need to write a letter and get the proprietary agreement, contact this gentleman over here at the microphone.

MR. MURRAY: We have a website that US citizens can go to and there's a process that, you know, is outlined there that they can follow. It usually just involves signing a non-disclosure agreement and sending that to us.

ARBITRATOR EVANS: I mean, it's fairly widely distributed now. We have people at Ohio State, Purdue, Penn State, a number of universities. You have to make sure that you don't go into business right away or give it to some country that may not have rights to it.

MEMBER POWERS: What is the export restrictions on this?

MR. BAJOREK: I think you have to be a member of CAMP and --

MR. MURRAY: Yes, generally what we do is internationally, there is -- we have the CAMP program the Code Applications and Maintenance --

MEMBER POWERS: I guess, have you talked to the Department of Commerce?

MR. MURRAY: No.

MEMBER POWERS: Maybe you'd better.

MR. MURRAY: At some point -- no, no, I believe -- OIP does and what happens, is as long as they're a member of the CAMP program, then there's those agreements in place. If the country isn't a member, then what we do is we point them our Office of International Programs but I believe that Department of Commerce has been involved in you know, SRMs that have come down from the Commission as far as reviewing the policies towards CAMP.

MR. BAJOREK: I think those CAMP agreements entail they have to sign the information, "Hey, that's only for internal use. They can't disseminate it to other organizations in the country.

They can't use it commercially to compete against the US". Concerns, there's a lot of restrictions. They can use it but the commercial applications are limited.

One of the reasons we want to get this documentation done and get the theory manual done by June is our intent is to start a peer review of TRACE and its documentation this year. Back in December, we weren't so sure about that because of the continuing resolution and funding but it looks like regardless of how the continuing resolution is resolved, we are going to be able to go ahead. We have a budget for this now and we're going to send this out. We're going to try to get a group of four to five, possibly six individuals. We're going to go through, they're going to review the conservation equations, the solution methods, the closure, look at the documentation, tell us if it's -- you know, if it's clear, also if there are technical problems they see in that, look at the assessment matrix, its breadth and range and conditions and contrast, backup codes with summaries.

If you think these -- we're going to request that we have people who are independent of the process so they're not people that were developing the code or were using the code over the last few years, they're kind of on the outside of this process, to be able to recognize the experts and they have good backgrounds and they're not going to profit. I think they're people that you would recognize and have some familiarity with in this field.

MEMBER BANERJEE: There is also verification need somewhere here which is that the correlations as written are actually programmed properly.

MR. BAJOREK: We're not going to ask them to do the line-by-line review.

MEMBER BANERJEE: Who's going to do that?

MR. BAJOREK: We're not going to assign that outside. That's going to be the responsibility of the people who are doing the programming. I realize that may be an issue but I'll give you an example. We did that when we were doing the TRAC code as part of its application. You look at that thing line-by-line and you almost never find a problem in looking at it in that context. Will those problems pop up with you use the code? You do an assessment, you do a plant calculation, you do one of those fundamental cases and then it pops up at you because you see something that's incorrect and then you go back and, ah-ha, that's the mistake.

Given the amount of effort that it would take to do the line-by-line review and the return on investment, our thinking is we don't think that's really the place to go right now. Peer review, absolutely, we want to do that, we're going to do that. We're going to continue to expand the number of assessment cases we do and when we find those errors, we're --

MEMBER BANERJEE: What concerns me about that, I think this is a beginning, but is that often, as you know, in codes, people go in and fix things. You know, if you've written a code yourself, you obviously know that. So that the code is going unstable here, you put a little fix, you put another little fix and soon the whole thing is run by these little fixes. And I'm very concerned about that instead of having clean code, you know. And most CFD codes can't have these fixes because they're too general. But codes like this particularly can have that and there has to be some independent view of that so that you're not just adjusting things to fit a few experiments here and there, you know, even though your matrix is large.

MR. BAJOREK: Okay, it's a point well-taken but --

MEMBER BANERJEE: It has to be very clean and transparent --

MR. BAJOREK: Okay.

MEMBER BANERJEE: -- however you do it.

MEMBER POWERS: Steve, let me ask you a question about your peer review here. You've looked at the documentation and you have words of clarity, ease of use and are your peer reviewers going to get the code and run it?

MR. BAJOREK: Well, make it available to them. We'll make the listing available to them so that if they want to go through and look at various places in the code, they're certainly free to do that.

MEMBER POWERS: I just commented that when peer reviews and codes have been done and we have had the people get the code and actually run it, not all of them do but some of them are, especially faculty members, take a graduate student running it. They're very imaginative at finding things that are wrong with the code that's very useful.

MR. BAJOREK: We'll make it available to them but I think our expectation is that they focus on the documentation. If they have suggestions on that, we can get those cases run and --

MEMBER BANERJEE: Knowing the people you are considering for the peer review, I think they'll run the code and they'll figure it out. It's a very good team.

MR. BAJOREK: Yes. Okay, we're going to try and start this review about the middle of 2007. We expect to have them go through the documentation, produce a report and give us their findings, give us their recommendations, probably towards the end of 2007, two to three to four months. It's kind of hard to estimate exactly how long that will take, but the idea is to get some relatively quick turnaround and get the comments so that we have a report and we have a presentation probably in the subcommittee maybe next December or next January, at some time that's convenient.

MEMBER POWERS: Are you doing this peer review like you would do an expert elicitation, where they go through and they look at your stuff and they say, "I found 50 things that I don't like so I've fulfilled my obligation, my contractual obligation", and send it in to you? Or are you having them come together with a consensus set of comments?

MR. BAJOREK: We want -- we want to have more than one viewer on each overall topical area.

Let's say for example, somebody is going to go through and look at the momentum equation and solution. We don't want that one person's opinion. We want two people at least to look at that knowledgeable in that area to come up with, "Hey, you know, this is flatly wrong, guys, you need to fix this; you know this is consistent with standard practice and other codes; gosh, this is the best thing that's ever been produced", give us some type of an indication of where they think these solutions are.

Likewise for the constituent relations, look at the CCFL relations and how we handle it in there. If it makes sense, if it's flatly wrong or, you know, is this consistent with what's done elsewhere in the code, but get that from more than just one individual so at least the whole team can buy into it. Although we realize, you know, we don't want to have all -- you know, out of five or six people, we don't want to have them all momentum equation experts and you don't want to have them all experts in nuclear coordinating either. You're going to have to have a mix. There's going to have to be some balance on that as well.

MEMBER POWERS: But you're essentially reviewing it like you would review a journal article.

You're going to send it out -- each section to two reviewers. You're going to get them back. One of them says, "This is better than putting beer in bottles", the other one says, "This is horrible beyond belief", and then you'll sort it out.

MR. BAJOREK: But we're going to get those comments to this committee or the thermal hydraulic subcommittee is going to hear those. And we're going to be able to take those and make improvements and corrections.

MEMBER POWERS: One of the things I fear and I'm sure you've thought about this, is that you call me up and say, "Tell me if I've calculated the solution activities correctly, I used the Bihuckle (phonetic) theory", and that's all you tell me. I write back and say, "You're unbelievably foolish. The Bihuckle is founded on an incorrect use of superpositional electrostatics. It's impossible to be more. You're beyond belief, you're heritage is in doubt, your sexual habits are weird".

(Laughter)

MR. BAJOREK: Other that that it's fine.

MEMBER POWERS: If on the other hand, you call me up and say, tell me, "I've done the activity coefficients in this solution and I'm going to use this for my -- for demonstration to my freshman class of chemists and I've used the Bihuckle theory". I'll say, "Well, fantastic, just the appropriate level of detail here". I mean, use makes a difference on these things. Do your reviewers understand that?

MR. BAJOREK: One of the things we've got to make clear, this code is going to be used to audit the likes of a RELAP, a TRAC, a COBRA TRAC, you know, CATHAR, and it should be fitting in that -- you know, it should be a member of that club, shouldn't necessarily be state of the art and significantly better but --

MEMBER POWERS: That's -- I mean, you're not using this to advance our understanding of a two-phase flow. You're using this to apply our understanding.

MR. BAJOREK: That's right. If we're going to be accused of advancing the state of art, we're going to have some mean discussions with our office director.

MEMBER POWERS: Some places you're going to have to, some places you don't have to.

MR. BAJOREK: Okay. Another important activity for really this year, 2007 and beyond --

MEMBER BANERJEE: By the way, there was a time when NRC used to advance the state of the art, not so long ago.

MR. BAJOREK: Those were the good old days. User support, one of the things that's going to be very important over the next several months is really bringing TRACE into the regulatory process. And there's four ways that we're trying to do that right now. We've been developing SNAP and I'm going to talk a little bit about that. We're doing some of our own planning for deck generation. We're taking some decks and we're improving those, making them better for a turn-key operation so that other people in the agency have something of a code. They have an input deck, they can run it, and they know it's going to work.

MEMBER POWERS: Do you have a user's group?

MR. BAJOREK: Not formally defined, no, but yesterday that's exactly what we were talking about as a way of sharing problems and successes and using -- in using a tool like this. Right now, it's more of the assessment group but we realize that has to expand as we start using this for other applications.

MEMBER BANERJEE: How widely is it used in

NRR right now?

MEMBER POWERS: How many people, yes, that's exactly what I was getting at.

MR. BAJOREK: Well, we have the TRACE -- we have some workshops, training workshops, so we're about four or five people from NRR.

MEMBER BANERJEE: Not just Walt, right?

MR. BAJOREK: Not just Walt. Veronica Klein, she has been using it with ESPWR, Pete Nyarski, another newer engineer, had been using it for some I think couple of TRACE parts calculations but I'm not exactly sure what he was working on. So there are a few people over there that have been using it. We want to grow that.

The problem that we -- that we see is we've got to get those people that have been used to and familiar with running RELAP to want to go here because they have their own job to do over there and a lot of times they have to come up with their solutions or their recommendations on a couple of months and they don't necessarily have the time to learn some of these new applications. So by improving on this but getting the decks ready and giving the workshop, we're trying to make it as easy as possible. But we realize there is a bit of a culture shock here.

MEMBER BANERJEE: How many decks do you have ready right now?

MR. BAJOREK: Can I walk us through the slides?

MEMBER BANERJEE: Okay.

MR. BAJOREK: And then finally, the other area of support is we make people in the Code Development Branch available so that as there are problems and issues with the decks, they have a person to go and help do the debug.

Just a couple of words on SNAP and what that really is; that's a graphical user interface that helps you process the input and the output. It's something that's used not only for TRACE, but you can use it for the contain code, containment, use it for MEDCORE (phonetic), use it for PARKS, kinetics code. You can use it for RELAP. If it becomes familiar with using this input processor, you've really got a leg up on using not only TRACE but some of the other codes. It's an important tool and we find that a lot of the newer users, people just coming out of school, this is their preferred way of preparing input deck. That's not true with everybody, okay, but we're finding that the newer generation wants to do this.

Now, the nice thing is that it gives you various menus and puts -- let's you put in the cells, the volumes, gives you a graphical display so if you inadvertently put in an area change, you're going to see that right away. It also goes through and helps you filter out some of the common errors that came be made in putting together an input deck and gives you that old ASCII card image deck of what the code is producing and that's where a lot of people are used to doing. So you can to through SNAP and you can still wind up at the spot that a lot of the older users have already become accustomed to.

MEMBER CORRANDINI: So if I just understand, so SNAP is a pre-processor for all of the tools you mentioned before?

MR. BAJOREK: Yes, yes.

MEMBER CORRANDINI: So you somehow have to then separately run it or use it and identify what the preprocessor -- what this eventually is going to be stuffed into.

MR. BAJOREK: Yes. You can't -- you don't have to do it. You can start with this -- the old ASCII card image and modify that but if you're an experienced user and you realize, "Well, I've got to change this card and this one and this one and the five down there", you can go ahead and do that. SNAP will force you to go through -- you make the change once and it should propagate in the places it needs to go.

MEMBER BANERJEE: Yes, but at one point, there was discussion and maybe this capability is still there, that you could just take a RELAP deck, for example, and use that as input for this code, if you chose, I mean, to do that. Is that capability there?

MR. BAJOREK: No, not completely. If you take a deck, and run it through SNAP, it will do something like 90 percent of the conversion. The user is still faced with doing that last 10 percent. That's one of the reasons why we're doing this --

MEMBER BANERJEE: How long does that last 10 percent take?

MR. BAJOREK: It depends on the user, it depends on the --

MEMBER BANERJEE: Let's say a common garden user, somebody who's been using RELAP.

MR. BAJOREK: I'd just be guessing. I really don't know. It's -- I believe that it is more frustrating to the user, okay, that they would rather go back and use RELAP because of it, okay. I think there is an important hurdle there. That because it can't do everything, there is an unwillingness --

MEMBER BANERJEE: What parts can't it do?

MR. BAJOREK: It is a mainly some of the signal variables, trips, control variables. If you just -- and they have to make a bit of a choice. They're trying to take a one dimensional curve, a one dimensional core and put it into a three dimensional core that TRACE wants. So there's some additional work and thinking that has to go on. People that have used it effectively to do the deck conversions have taken a loop, you know, a bunch of pipes and tees, sent that through SNAP and that transferred relatively clean. So of you're clever on SNAP, you're able to really speed up the process, but it won't do everything.

The other thing that SNAP helps you with is on the output side. It allows you to develop mass, display the information, show you what's going on in the transient and some people, you know, have gotten pretty clever on putting these together and setting up other windows so that the deck can run in real time. On their PC they can actually monitor their line in progress. We had a fellow last summer who actually took this and developed this using SNAP to output or to show experimental data, test data what can likewise show a system and how the system is behaving based on the DP cells and the temperatures.

So it's got a number of features to do that, but as you were getting to, no, SNAP does not take our old RELAP deck and send it through all the way. There are a very large -- a fair number of TRAC-P and TRAC-B decks already in existence for --

MEMBER BANERJEE: That would be for large break LOCA, right?

MR. BAJOREK: Large -- well, large, it's a plant deck. That's an e-mail, I asked Joe Stodmayer what decks really are available and there is a large number -- a fair number of plants represented, Westinghouse 2 LOOP, 3 LOOP, 4 LOOP, BNW plants, sever BWR plants. If you want to take TRACE and run it right now, it will accept the TRAC-P or TRAC-B format and it will run those. Now, if you want to change notalization if you want to do a plant upgrade, you can take those -- that card that you made the changes or you can use SNAP which will take those decks and make your changes. But that's still a little bit of the culture shock. I would be willing to learn that new tool or put up with some of the frustration in a newer piece of software.

So to get around that, we've started on an input deck modernization project working with NRR, to identify which plants are of most interest to them. We're going through and we have an initial list; Brown's Ferry, a Westinghouse 4 LOOP, a model that represents actually several different plant type, a Westinghouse 3 LOOP plant and a combustion engineering plant, an older vintage one, and we're taking those decks, some TRAC B and RELAP. We're setting them up so that they were run completely through SNAP. We're running a large break transient, a small break and a transient that's maybe two blocks or something like that, to insure that these decks work, they're completely in TRACE in a TRACE format. They are with the latest set of guidelines because if you look at those older decks, they may have a cruder notalization in the core than what we would recommend with our latest assessment, so we're improving that.

So as we go through these decks, we're making sure they not only work with SNAP, they are in a complete TRACE-B input when they're finalized but they're also modernized to make sure that if there's anything that should be changed to make them consistent with how we've done the assessment, okay, those are also in those decks as well.

Brown's Ferry should be done in several

weeks, it's pretty near-term. Likewise the Westinghouse 4 LOOP plant.

MEMBER BANERJEE: In Brown's Ferry, the NRR has already done the calculations of the RELAP, right? So why are you choosing Brown's Ferry?

MR. BAJOREK: They asked us to do that.

MEMBER BANERJEE: Was it for a comparison with RELAP or --

MR. BAJOREK: No, to get that model to run with TRACE.

MEMBER POWERS: It is representative of a class of Mark I BWRs with very high power.

MR. BAJOREK: It may be used in other jobs but the idea is to develop a TRACE Brown's Ferry deck, run it through some of its cases so that in the future you don't have to use RELAP, you can use TRACE.

MEMBER BANERJEE: Well, my concern is that each of these decks, if I remember RELAP, is very, very reactor specific. I mean, it's not a generic deck. So what we are dealing with is really developing 100 or whatever, 50, a large number of decks because these are all specific to each reactor and it takes a lot of time to develop this. And these guys already have that based for most of these reactors, something or the other did with RELAP.

MR. BAJOREK: Okay, this is what they asked us for, then the other plants as well. This initial batch will be done some time this summer, a couple of near term, the H.B. Robinson, Calvert Cliffs, the deck should be around in about June of this year. Between these decks, which exist and the ones which are updated, you have a fair number of cases that you can actually take and run with TRACE and you have all the documentation you want for this year. Beyond that, we're going to do the same conversion and updating and keep in mind this updating is also taking the previous deck and bringing it in line with the most current tech specs.

If you look at some of the old models, and this is both RELAP and TRACE, those decks were developed some years ago and they may not necessarily represent the plant with the latest new generator, two level, the latest power after some of these have uprated several times and other changes that have been made to the plants over the years. So we're trying to upgrade the input as well as the boundary conditions for that model to get it as close to the plant as it is today but we're doing that with a couple of B&W plants, a higher power Palo Verde, a Boston additional plant, some additional BWRs, Westinghouse 2 LOOP and a Westinghouse 3 LOOP and another 4 LOOP slightly more core and a little bit, I won't say odd but it has three accumulators on 4 LOOPS which makes it a little bit unique.

We have a model for ESBWR. We're going to be doing the conversion for an ETR deck and we're going to be upgrading our AP-1000 deck for TRACE as well. The bottom line is within six months and whenever these other decks get together, the type of plants which have been of most regulatory interest of late, we're going to have TRACE and SNAP working for us in a very large assessment base which will demonstrate how the curve should work on the phenomena that effects it.

MEMBER BANERJEE: How much effort is going into this?

MR. BAJOREK: How much effort?

MEMBER BANERJEE: Yes, in terms of developing these plant decks.

MR. BAJOREK: Right now this work is at a contractor. They have several people working on it. Do you want how long it takes to do one of those decks versus --

MEMBER BANERJEE: Yes, how many man-months, man-years whatever?

MR. BAJOREK: Generally, we can -- depending on what we start with, you can upgrade one of those I think it's taking on the order of two or three months per plant.

MEMBER BANERJEE: Man-months.

MR. BAJOREK: Staff-months.

MEMBER BANERJEE: Oh, sorry, staff months.

MR. SIEBER: Are you going to make any effort to go into the later model replacement steam generators, for example, like the Model 51? Generally, they're put in 53 or 54,000 square feet of Alloy 690 tubes in there which gives you a little bit different characteristic but this is where the plant uprates and PWRs is doing to come from.

MR. BAJOREK: Yes, well, we're trying get the most recent model in there. I believe in South Texas one, they have the one used for the model length. That's the idea, to try to get the latest information that we can from the utilities and make these decks as current as we possibly can.

MR. SIEBER: I just thought the steam generators wouldn't be tough like modeling the whole plant.

MR. BAJOREK: I'm sorry, I didn't --

MR. SIEBER: Just updating the steam

generator portion would not be as difficult as trying to construct a deck for a whole plant.

MR. BAJOREK: No, and also one of the things, if you noticed, we're picking some plants with different steam generators so as time goes on, we're able to go and take a steam generator model that's developed and use it on a different vessel if you have to. So we're kind of developing tools for the future as well.

MR. SIEBER: I just didn't see any of the more modern replacement steam generators in that list.

MR. BAJOREK: Okay.

MR. SIEBER: You might want to think about it.

MR. BAJOREK: Okay.

CHAIRMAN SHACK: The biggest headache in doing a steam generators upgrades is getting the data from the people.

MR. BAJOREK: Yes, that's a generic problem. It's very difficult for us to go back and try to get, "Hey, what's the latest set of conditions for the plant, the steam generator", but the thermal hydraulic conditions are what works. You know, you have to get those from the vendor somehow, fuel information. Okay, these plants change fuel and in some cases change vendors two or three times.

The model that may have been set up in 1990 probably has an obsolete fuel product in there right now. And they're trying to --

MR. SIEBER: As long as the pitch isn't -- that might not be so bad.

MR. BAJOREK: That won't change but they're putting in more grids. The drywell resistances are changing and there's a lot of -- in some cases they're getting smaller. And it's --

MEMBER POWERS: And for the BWRs there's no hope in the life if it's 10 years old.

MR. BAJOREK: In summary on where we're at with TRACE, we've reached a major milestone. We've frozen the code. We're not actively doing model development in pursuit of a 5.0 version at this point. We've released in internally and we're using it now to finish our documentation to support the documentation for the assessment cases that we've run.

As we go through the some 500 assessments, we feel that by and large it's -- it does a reasonable job right now. There are places that we know it needs to be improved. We're making note of that and that's what our efforts are going to be directed at as we come out with later releases, 6.0 and 7.0. One of the other things that we've done with these assessment cases is we've automated the process so that when we take these 500 some input decks and we want to rerun because we've made a code change, it's not something that would take a year or months has it had been to two or three years ago.

And we're able to take the latest version of 5.0 rerun all of those cases and have them in a couple, three weeks, actually, a little bit less than that. That really frees up our manpower now. Instead of going through and running all of these things manually, we can increase our assessment basis, look at things like in this facility for B&W plants or test material in maybe a little bit more useful for injection plants, expand our matrix or look at more capable in that regard, without having to spend a lot of manpower to run all of these decks every time we make a code change. So as we start to develop the TRACE 6.0 or 7.0 or whatever the number is going to be, we're going to preserve this assessment matrix and we're going to be able to rerun this relatively quickly and we think, our hope is that we're not going to see this big delay between a code version and its documentation.

When you do this automation, those figures get automatically updated and we think that that time frame of years is going to come down to months or weeks and I don't know exactly what that's going to be. We'll have to go through that cycle. That's the reason documentation is a high priority. Our goal now is to get that wrapped up by about the middle of this year and initiate the peer review. We are doing our best here to try to rapidly get TRACE to become the code of choice here in the agency, improving the input steps, we're conducting training workshops for both SNAP and TRACE.

We're continuing to work on SNAP, putting more feature in that to try to get diagnostics and make it a little bit easier for the users to use. We realize that there are obstacles to getting TRACE getting used by everyone but we think we have that manpower and the plan now to bring that into fruition. That wraps up what I have on the TRACE and its documentation. And I was just going to briefly talk about the other issues if you want to hear that or if you have any questions on this.

CHAIRMAN SHACK: Onward.

MR. BAJOREK: Onward? Two other things that we talked about on December 5th; one was an anonymous letter sent to the ACRS that was talking about the method in both TRAC and TRACE about which we saw the equation state. Didn't like the approach, was recommending a different type of approach. I'm not going to go into the details on what this all entails but just tell you what we have done. We've taken this, we've given this to John Mahaffy of Penn State to go through, evaluate the author's claims and criticisms of the code.

Dr. Mahaffy has gone through, he's looked how that equation state in linearized and how it's solved and his conclusion is that what we're doing in TRACE and have done with TRAC is generally standard practice. The author has some points but they're not necessarily things that could be implemented in TRACE or they're not things which would necessarily improve upon the calculations. So in our minds, we've addressed the issue, we've looked at it and don't feel that there is a significant problem. We're going to document these findings in letter or report and close out the issue.

We don't know --

MEMBER BANERJEE: But that was two months ago and the presentation to the subcommittee was -- I think we would agree with the conclusions perhaps, but the case was not made at the subcommittee meeting to support that. I mean, we all came to the same conclusion but that case needs to be properly documented and put forward. Now why has it taken two months to do that?

MR. BAJOREK: I don't know.

MEMBER BANERJEE: In fact, other people where there and they made comment on it, but I got the impression that the reply was pretty sort of waffly and not very to the point. Maybe somebody else should give their opinion on that.

MR. BAJOREK: Well, we've asked John to do two things in the last couple of months, close this out, address those issues and complete the documentation but also revise that section on conservation equations and field equations. I wanted to work on the field equations because we want to get this theory manual done.

MEMBER BANERJEE: Sure. This didn't look like a huge thing to close out rapidly.

MR. BAJOREK: I agree, but John's priorities has been on the theory manual and on other sections, but out intent here, I mean, is to be consistent with the conclusion. We don't think it's a problem. John needs to complete his evaluation and document that in a report. But I wanted to say that if we have addressed this. We think we can bring it to closure here.

The other issue we talked about, more commonly referred to as the Pi Group Ranging issue. This was one that originated really in the AP-600s. There were five different scaling methodologies that were proposed to look at scaling of large integral facilities to the full-scale plant. First, I said, well, a scaling group, a Pi group which is the ratio between that dimensionist group and getting for the test facility and prototype but between one-half and two, that's accepted. We looked around and for a basis for that. We couldn't find anything. Over 8600 this more or less became a de facto standard without a basis. Sounded reasonable to most people. That's how the scale evaluations were done.

But we were asked to look at this and really try to establish why should it be one-half to two, why not one-third to three or why not something tighter than that? And what we've done is we used AP-600 and one of the ROSA tests as an example and have established really a map or a set of guidelines to guide someone through this process.

I want to just summarize the key features, but rather than focusing on a range for that particular scaling group, you should really focus your attention on what is the range that you want for your figure of merit. Now that might be a cladding temperature, it might be a mixture level of pressure and containment. You have to establish some range over which you think it's tolerable to allow that to be generated in your comparison to your experiment.

So, you establish that range first and develop mainly, almost on first principles, a very simple model of that system or part of the system that you want to investigate. We'll use like the tank, the vessel for AP-600. You'd use your conventional mass and energy conservation equation to derive a scale of expression against your scaling groups and put those in what Marino (phonetic) would refer to as a trajectory equation. This is something that allows you to go back and look at sensitivities to those scaling parameters and how they impacted your figure of merit.

MEMBER KRESS: Are these partial derivatives?

MR. BAJOREK: In some cases, yes. You see that in some of the volumetric --

MEMBER KRESS: But these things may vary with time.

MEMBER BANERJEE: They're usually lumped parameter.

MEMBER KRESS: For deltas.

MEMBER BANERJEE: Yes, usually. They're time varying.

MEMBER KRESS: But they're individual -- effects of an individual power group on a figure of merit.

MR. BAJOREK: Yes.

MEMBER KRESS: Not all at the same time.

MR. BAJOREK: Not all at the same time.

MEMBER KRESS: And maybe looked at over a range of times or --

MR. BAJOREK: Yes, yes.

MEMBER KRESS: -- and a range of --

MR. BAJOREK: You still have to work our a particular --

MEMBER KRESS: You would hold the time groups that you weren't looking at, at a constant value or would you have to have a whole matrix of --

MR. BAJOREK: No, no, no, no matrix.

MEMBER BANERJEE: I guess it's just a linearized --

MEMBER KRESS: Linearized.

MR. BROWN: -- yes, around the uncertainty associated with --

MR. BAJOREK: You would vary things one at at time. Okay, hold the other constant, and look at the impact of that group while the others were constant. That group would vary in time over that period of the transient and its impact on the figure of merit.

MEMBER KRESS: Now, you're looking at say the power group for a prototype.

MR. BAJOREK: Uh-huh.

MEMBER KRESS: But these pis we're talking about is the ratio of test to them. Now, how --

MR. BAJOREK: No, no, no, no, these would be -- these would be dimensionalist quantities. It would be that came out of your scaling equation, not your number or it might be some dimensional quantity. For example, if you remember when Dr. DiMarzo did the tank problem, one of the quantities was a -- was like a mass inflow --

MEMBER KRESS: So feeding on this what I all partial derivative, you may get a different range for each different pi group or each different separate type of FOM and --

MR. BAJOREK: Yes.

MEMBER KRESS: -- you might get lots -- is this going to be calculated internally some way?

ARBITRATOR EVANS: Calculated?

MEMBER KRESS: I can't see as you're going to come up with a range --

MEMBER BANERJEE: If you have a different range.

MR. BAJOREK: Oh, yes.

MEMBER KRESS: Yes.

MR. BAJOREK: Go to the last page.

MEMBER CORRANDINI: That's a different time.

MR. BAJOREK: When you look at the individual scaling groups, you will find that you can categorize these as rules which are damped or amplified in Dr. Molina's terminology. Basically, they're groups that if I expand that range from instead of .5 to 2 I make it .1 to 10, it has virtually no impact on the figure of merit.

MEMBER KRESS: Because the derivative is pretty small.

MR. BAJOREK: It's small. There are others that relative modest changes in that parameter cause big variations in the figure of merit. Those were considered amplified. And when he went through and did the AP-600, during the ADS blowdown period and the tank is blowing down and the rest of the system is interacting with it, your PRHR heat removal pi group and there's more to it that just -- you know, it's a combination, its impact on vessel level over that range .5 to 2 was fairly small, just a few percent.

Likewise the CMT flow which isn't effected during that period had almost no impact or no change going from .5 to 2. But our scaling groups which were related to break flow and accumulator flow, both of which were very active during that period, now you'd want to restrict that scaling range to something less than .5 to 2. In the case of break flow, we're looking at oh, maybe something in .8 to 1.3. You know, a much tighter range.

MEMBER KRESS: If you wanted a plus or minus 10 percent impact.

MR. BAJOREK: Right. And in the -- in the evaluation, the idea was take vessel inventory on a level if you really want to get right in this test, and you know, we can be a little bit non-conservative but on the conservative side, you want to be within 10 percent. Now you have a way of seeing what range that pi groups should be allowed to --

MEMBER BANERJEE: So you're saying these are the pi groups related to the --

MR. BAJOREK: Related to that, yes.

MEMBER BANERJEE: Related, which influence this.

MR. BAJOREK: Yes. So the conclusion is that acceptable scaling shouldn't be based on fixed range, okay. They are going to vary individually and you need to go this additional step from the conventional scaling methodology to looking at the impact of what those parameters are.

MEMBER CORRANDINI: Did this surprise you?

MR. BAJOREK: No, not really but the problem was we didn't have an intermediate step here because we knew there might be a problem with the scaling group but we don't have a code that's perfect in order to get those sensitivities.

MEMBER KRESS: Yes, sensitivities.

MR. BAJOREK: So I think the nice thing on this is I don't have to really -- I don't have to depend on the code to throw out that first hour and a half talking about TRACE. I don't need a code at this point to evaluate whether my tests are scaled appropriately. I should do that on a scaling related that --

MEMBER BANERJEE: That's probably too strong a statement. What you want to know is that the scaling of the tests at least produces data which is applicable to validation of your quotes or whatever. I mean, if they're so distorted that they produce phenomena and stuff that have no interest, then clearly the data is less meaningful than properly scaled facilities.

MR. BAJOREK: But once we get that step then we can complete the assessment and if we're getting a PUMA correct, and we have the right scaling rationale then we've got a lot better confidence to extend that code to a full scale prototype. So it's an intermediate step here but I think the important conclusion is if you come in and you say .5 to 2 because the last eight or nine scaling houses use that, you really need to rethink those numbers.

MEMBER BANERJEE: I think the subcommittee commented at that point that it should be documented into some sort of a methodology which could be used just as the previous scaling methodology was documented and applied.

MR. BAJOREK: Yes, and Dr. DiMarzo has been going through and taking the report and making it more of a -- less of a demonstration and generalizing this as an approach now. So we're working on it now. But I just wanted to give the committee an idea of where we're headed with that. Again, we have to complete the documentation and make the report but I think the conclusion is --

MEMBER ABDEL-KHALIK: How do you do final distortions on the previous grant (phonetic)?

MR. BAJOREK: The impact over here, that's should really be replaced. That's really a vessel level. The important thing for AP-600 was whether we'd see a level dropping of the top core level. The tests were all monitoring these levels in the upper part and the idea here was to really look at the change in that level in the test versus the break, the cumulator flow the core makeup tank flow and how it changed relative to what it might do in the AP-600.

I think the scale is a little bit convoluted but the idea here was we can allow the plant to have higher levels than the test, okay. You could scale in that direction. That would be conservative but we didn't want to go in the direction where the test gave you one level and in reality the plant would give you a lower core level. So the idea here was we need to run the test. If 1.0 were the spot, you know, you'd like to be, we don't want to deviate from that by more than 10 percent in a non-conservative direction or 12 percent in a conservative.

MEMBER BANERJEE: He gave you a straight answer to your question.

MEMBER KRESS: Yes.

MEMBER BANERJEE: Distortion is just the -- it's not distortion, it's the value of the pi group, let's say a full (phonetic) number or something.

MEMBER KRESS: Yes, but the problem I have with that is --

MEMBER BANERJEE: The ratio of that to that in the full scale plant to that facility so if that ratio is wrong by a factor of two, it gives you a fairly significant --

MEMBER KRESS: But if you look at the break flow, there's more than one pi group.

MEMBER BANERJEE: Oh, sure.

MEMBER KRESS: And then so I don't understand how many pi groups go in that access down there to get that distortion or did you summate all of them or --

MR. BAJOREK: I didn't do this.

MEMBER KRESS: I know but it's the question I'm --

MR. BAJOREK: I didn't want to go through all of the derivations but in this trajectory equation, there are four dimensionless groups, four or five groups that we get out of this. That's where -- that's what's being represented with --

MEMBER KRESS: And you use the maximum one or --

MR. BAJOREK: Maximum one?

MEMBER BANERJEE: Yes, you know, the whole -- without going into the methodology right now, what you do, of course, is that you do an order of magnitude analysis. You non-dimensionalize equations and --

MEMBER KRESS: Yes, I'm familiar with that.

MEMBER BANERJEE: -- and once you do that, then all the derivatives and everything become the order of one.

MEMBER KRESS: Order of one.

MEMBER BANERJEE: So that each term is as important as it's coefficients. So you take -- the coefficients are a non-dimensional group. So you only keep the terms with the largest coefficient. So you evaluate these and I guess what they're doing is taking the largest coefficient that effects the break flow.

MEMBER KRESS: That's actually my question.

MEMBER ABDEL-KHALIK: But philosophically, if you had a perfect code, and you understand the physics, then it doesn't matter what the scale is because you're verifying phenomena. And therefore, by this process, you're essentially saying the code is nothing more than an empirical fitting tool for the experimental data. Is that true?

MEMBER BANERJEE: It cannot predict new phenomena.

MEMBER ABDEL-KHALIK: Because you are limiting the range of applicability of the code, essentially, to a rather narrow range around where the experiment is. So the code, you philosophically by doing this, you're viewing the code as nothing more than an empirical fitting tool.

MR. BAJOREK: I think that's an accurate statement.

MEMBER POWERS: Do you really want to say that though? I think that's what he was getting at.

MEMBER BANERJEE: It's not predictive of new phenomena.

MR. BAJOREK: That's the -- these codes are not based on first principles. They are based on and held together by closure relations which are based on sub-scale experiments. A lot of those correlations come from single tube tests and you are using that at faith when you start to look at larger and larger scales. Assessment helps to benchmark and let you know whether those correlations are truly applicable with those other conditions but going back to the experiments, we all in integral tests in particular, you want to try to establish a basis for that system global-wide behavior and is it going to behave much like you'd expect in something with much larger scale. But the smaller scale test, that's all you have to run the full test.

MEMBER BANERJEE: As we come to full scale tests.

MR. BAJOREK: If we had full scale tests the --

MEMBER BANERJEE: The assemble system, we can do it in components.

MR. BAJOREK: Components, yes. That's all I have on the pi groups. If there's any questions on any of that, I'd be happy to try.

MEMBER KRESS: I think that's a good stopping point.

CHAIRMAN SHACK: Well, if there are no

further questions, I'd like to end today's meeting here. I think we're at the end of the transcription. The committee shouldn't run away. We need to come back and discuss letters, but I assume everybody would like a 10-minute break and we'll come back -- we want to give Otto and Mario some guidance on the letters that they're going to be preparing. So that's what I'd like to do when we come back.

MEMBER KRESS: On Brown's Ferry and --

CHAIRMAN SHACK: Oyster Creek. And we want to discuss whether we want to do a letter on TRACE or not. We'll put that off until --

MEMBER BANERJEE: I have a draft letter anyway.

(Whereupon, at 5:59 p.m. the above-entitled matter concluded.)