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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

NOVEMBER 8, 2001

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

487th MEETING

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THURSDAY,

NOVEMBER 8, 2001

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ROCKVILLE, MARYLAND

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The committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., George E. Apostolakis, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

GEORGE E. APOSTOLAKIS	Chairman
MARIO V. BONACA	Vice Chairman
NOEL F. DUDLEY	Member
F. PETER FORD	Member
THOMAS S. KRESS	Member
GRAHAM M. LEITCH	Member
DANA A. POWERS	Member

COMMITTEE MEMBERS PRESENT: (cont'd)

STEPHEN L. ROSEN Member

WILLIAM J. SHACK Member

JOHN D. SIEBER Member

GRAHAM B. WALLIS Member

ACRS STAFF PRESENT:

SHER BAHADUR

SAM DURAISWAMY

CAROL A. HARRIS

JOHN T. LARKINS

HOWARD J. LARSON

MICHAEL T. MARKLEY

ALSO PRESENT:

RALPH ARCHITZEL

STEWART BAILEY

RAY BAKER

RUSSELL BELL

JEFF BENJAMIN

BILL BURCHILL

WILLIAM BURTON

GENE CARPENTER

ED CONNELL

JIM DAVIS

ALSO PRESENT: (cont'd)

JOHN FLACK

CHRISTOPHER GRIMES

ALLAN HAEGER

TIM HANLEY

DONNY HARRISON

JAMES W. JOHNSON

ED KENDRICK

TOM KING

MARK KLUGE

TAD MARSH

MIKE MAYFIELD

SCOTT NEWBERRY

JOHN NOSKO

CHUCK PIERCE

JASON POST

LARRY ROSSBACH

MARK RUBIN

JERRY N. WILSON

RAY P. ZIMMERMAN

JOHN ZWOLINSKI

I N D E X

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

(8:30 a.m.)

CHAIRMAN APOSTOLAKIS: The meeting will now come to order. This is the first day of the 487th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting the Committee will consider the following: final review of the Hatch license renewal application, Dresden and Quad Cities core power uprate, NRC Safety Research Program proposed update to 10 CFR Part 52, and proposed ACRS reports.

A portion of this meeting may be closed to discuss General Electric nuclear energy proprietary information applicable to Dresden and Quad Cities core power uprate.

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

We have received a request from Mr. Russell Bell of the Nuclear Energy Institute for time to make oral statements regarding the proposed update to 10 CFR Part 52.

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

I'd like to bring to your attention three speeches that Chairman Meserve and Commissioner Dicus gave recently. They are in this handout, "Items of Interest." In particular, the speech by Commissioner Dicus on new directions in research should be of interest to the members, since we are working on our report on research being carried out by the Office of Research.

These speeches were given at the Water Reactor Safety -- no, it's not Water Reactor anymore -- at the Nuclear Safety Research Conference, which used to be Water Reactor Safety Information Meeting -- a very significant change in name.

I would like to remind the members that during lunchtime today they will -- they are scheduled to interview three candidates for potential membership of the ACRS. Dr. Larkins has a comment to make.

DR. LARKINS: Yes. Please note the members in Group 2, Bonaca, Powers, Rosen, Leitch, and Wallis, you are now going to have your interviews in

the Subcommittee Room rather than the Caucus Room. So please make note.

CHAIRMAN APOSTOLAKIS: Thank you.

DR. LARKINS: That's both today and tomorrow.

CHAIRMAN APOSTOLAKIS: Any comments or statements any of the members wish to make before we start?

Okay. The first item on the agenda is the final review of the Hatch license renewal application. Dr. Mario Bonaca is the cognizant member. Dr. Bonaca?

VICE CHAIRMAN BONACA: Yes, Mr. Chairman. We met on October 25th with the applicant and with the staff to review how open items on the Hatch application are being resolved. We note that several of the open items on these applications were also open items on previous applications as well as on some applications under review right now.

So we were interested in this resolution, and we were interested in how the clarification will be brought to other licensees for future applications, so that there will not be open items in the future.

We felt that the SER contains significant clarification of staff position of these issues, and we were interested also in reviewing the appeal

process that had been used at least partially by this applicant with the staff. This is the first time we have seen -- at least from license renewal -- the appeal process underway.

We have requested the staff to come and give us some highlights of that meeting. And with that, I will invite Mr. Grimes of License Renewal to open the presentation.

MR. GRIMES: Thank you, Dr. Bonaca, and good morning, Chairman Apostolakis and other members of the Committee.

The staff is pleased to have this opportunity to present the results of the staff evaluation of the Hatch license renewal application. As Dr. Bonaca pointed out, we continue to learn some lessons in ways to clarify and improve the license renewal process, and we're going to continue to pursue those and keep the Committee informed as we make improvements to the guidance and to the process.

But our focus today is to present the results of our review of this specific application for renewal of the Hatch operating licenses and to describe the resolution of the open items and the basis upon which we will move forward to make a recommendation to the Commission.

And so we hope that today we can describe that to you and find out what the Committee views are on whether or not there's any matter that we need to clarify. We're still considering whether or not we want to revise the safety evaluation to make further improvements before its final publication and presentation to the Commission.

And so at the conclusion of this meeting I will want to make certain that we clearly understand what the Committee's views are on whether or not there's anything additional that we need to do before preparing a recommendation for the Commission.

With that introduction, I would like to turn the presentation over to Butch Burton, who is the Senior Project Manager responsible for the Hatch license renewal review, unless there are any particular overview questions that you have of me.

MR. BURTON: Okay. Thank you, Chris.

As Chris mentioned, my name is Butch Burton. I'm the Lead Project Manager for the staff review of the Hatch license renewal application.

What I'm going to try to do today is rather than getting into a whole lot of detail related to the review, I'm going to try and paint an overall picture of the application, some of the challenges

that the staff encountered during its review, how we dealt with some of those challenges, and, then, of course, if there are specific questions, detailed questions that any of you have, hopefully either I or some of the staff who are here today can answer those.

Let's start with basic plant overview. Can everybody hear me? Because I'm using the remote mike.

And this is similar to the slide that I showed, what, about six months ago when I was before you before. A little bit of background about Plant Hatch. The application was submitted in late February of last year. As you all know, it's a two-unit BWR located in Appling County, Georgia. I believe the largest metropolitan area is Savannah, about 90 miles northeast of the plant.

Unit 1, its current license expires in 2014. They're asking for a 20-year extension to 2034. Similarly, Unit 2, current license expires in 2018, and they're requesting an extension to 2038. Our initial SER was published in February of this year, and we issued the final SER in early October.

I'm actually going to begin at the end. Let me talk a little bit about the staff's conclusion, and then I'll talk about how we reached that

conclusion.

10 CFR 50.29 discusses the three criteria that are necessary in order to approve the license. The first, which is really the essence of our staff safety review, is that actions have been identified and have been or will be taken such that there is reasonable assurance that the activities will continue to be conducted in the renewal term in accordance with the current licensing basis. That's what we're -- the bottom line of what we're trying to get at.

In addition, this second bullet has to do with the environmental portion of the review, and the final bullet here has to do with basically if there were any requests for hearings, any issues raised there. And for Hatch there were none.

So, basically, the three main criteria to issue the renewed license, we believe that the applicant has met that, and I'll go through in the presentation to show you why we believe that.

Okay. The Plant Hatch application, as you know, is the first BWR, and it had a very unique approach. And some of the things were: it was the first to use the topical reports, the boiling water reactor vessel and internals project reports. It was the first to use that, so that was the first time that

we were able to apply those to a plant.

Southern Nuclear, who submitted the application, it actually used a different approach than some of the previous applications. They used a functional approach as opposed to a system approach, and that was a challenge to the staff. And I'll talk about that a little bit more when I talk about scoping.

It was also the first to apply the Aging Management Program attributes, the 10 attributes. They applied them not only to the Aging Management Programs, as we are used to seeing, but they also applied them to demonstrating the adequacy of the aging management. And I'll talk about that a little bit later, but that also posed initially a challenge to the staff.

All right. The first thing that we look at that the staff does in its review is it looks at the scoping and screening, and there are actually two parts to this. The first part is we look at the actual methodology that's used for scoping and screening. That's real critical, because if we can't have confidence in the process that they use to get their results, then everything else is questionable.

So we do spend a fair amount of time in

the beginning of the review to make sure that we understand the methodology and that the methodology is in accordance with the rule.

As I mentioned before, they were unique in that they used a functional approach versus a system approach to their scoping. So the functional boundaries were very important, because the functional boundaries were not necessarily the same as the system boundaries.

And the staff -- we did our review by system, so what happened was an individual reviewer would look at his or her particular system, look at the functions that that system performed, and then had to follow that and trace that through.

The end of the system wasn't necessarily the end of the function. So what we found was that system reviewers who were doing the scoping, there was a lot of crosstalk. As they followed the function and they reached the end of their system, they had to talk to the next person who was handling where that function picked up.

So there was a lot of crosstalk that was done in making sure that we could follow the functions through. And as I mentioned before, the scoping and screening requirements for the methodology should meet

the Part 54 requirements.

A little bit later on, I'm going to be talking about some of the various inspections that we did. And there was -- one of the things that we did to support the methodology findings was we actually went down to the applicant's headquarters and actually conducted a methodology audit. And I'm going to talk about that a little bit later.

As I mentioned, the scoping and screening review consisted of two parts. The first was looking at the methodology. The second part was actually looking at the results of the methodology. And this is just sort of a summary of what we found there.

As a result of our review, we found -- we developed 119 scoping and screening questions -- RAIs -- and also we had four scoping and screening open items. Again, this portion of the review was also supplemented with a scoping inspection, different than the audit that focused on the methodology. The scoping inspection actually focused on some of the results of the scoping evaluation. And, again, I have a separate slide that talks a little bit about the detail of that.

After the scoping and screening, the next was aging management -- aging management and time-

limited aging analyses. This is where we get into some of the Aging Management Programs. Once they identify which structures and components should be in scope and subject to an AMR, now we look at, what are the aging effects, and what programs are in place to manage those aging effects? That's what this portion of the review did.

It turned out, when all was said and done, there are 31 Aging Management Programs that are credited for license renewal. Eighteen of them were already existing programs, five were existing but needed some enhancement of some type, and then eight of them were new. And, in fact, in the original application there were 29 Aging Management Programs.

As a result of the staff's review, there were two additional ones that were developed. One was the diesel generator maintenance activities, which really dealt with the management of some of the skid-mounted components with the diesel, and the other was aging management of cables. So there were actually two additional programs that came out as a result of the result.

VICE CHAIRMAN BONACA: I thought that small bore piping inspection was a new one-time inspection.

MR. BURTON: No. Actually, the small bore piping inspection that came out as a result of the open item, that was actually covered in the scope of the treated water systems piping inspection, one of the -- I believe that inspection was a new program, and that is a one-time program.

And so the small bore piping, once we decided what it was going to be, we found that the TWPSI, as they called it, could actually be covered in --

VICE CHAIRMAN BONACA: Yes. So --

MR. BURTON: -- in the unit.

VICE CHAIRMAN BONACA: So, I mean, you resolved it by including it in the existing -- so you modified an existing program to accommodate that.

MR. BURTON: Correct. Correct.

VICE CHAIRMAN BONACA: Okay.

MR. BURTON: There are a couple of specific Aging Management Programs that I think probably require a little bit of discussion. One is the Corrective Action Program. That is a separate Aging Management Program, but it applies across many different systems.

And what it is is that any time you find evidence of age-related degradation, how do you

disposition that? And the Corrective Action Program provides the guidance and the requirements and acceptance criteria to do that.

In terms of the 10 aging management program attributes that I mentioned before, this single Aging Management Program covers four of those attributes -- the corrective actions, the confirmation process, administrative controls, and operating experience. When you go to that Corrective Action Program, it discusses how to address those four attributes.

VICE CHAIRMAN BONACA: Is this a program separate from the plant Corrective Action Program?

MR. BURTON: No. No. It is the same one.

VICE CHAIRMAN BONACA: Okay.

MR. BURTON: And, in fact, and what I was going to get to before, is that is -- that has an Appendix B pedigree, but what Southern Nuclear has done, even those portions that are in license review that normally do not have an Appendix B pedigree, those have all been upgraded to that level of oversight.

Again, some of the statistics. As a result of this portion of the review, there were 308 RAIs; 170 were related to the Aging Management

Program, and I want to explain that. And as a result, we had 14 open items.

If you look at --

MEMBER LEITCH: Butch, can we just go back to that Corrective Action --

MR. BURTON: Sure.

MEMBER LEITCH: -- Program again for a minute? So let me understand, that when there's an unexpected aging degradation, and the commitment is that they would put that into their Corrective Action Program.

MR. BURTON: Yes.

MEMBER LEITCH: Right? Now, that has all the attributes of a Corrective Action Program, including trending?

MR. BURTON: Yes.

MEMBER LEITCH: So that --

MR. BURTON: Root cause analysis, extent of condition, all those. All those.

MEMBER LEITCH: Now, what is the licensee's commitment to that Corrective Action Program? In other words, that's just a program that's in their administrative procedures, is that right? In other words, what flexibility would they have over these additional 20 years to change that program?

MR. BURTON: Ah.

MEMBER LEITCH: Say, for example, they decide, well, we're not going to have trending as a part of that program anymore.

MR. BURTON: Okay. Good question.

MEMBER LEITCH: Do they have that flexibility? How would that be controlled?

MR. BURTON: What happens is that all of the Aging Management Programs are ultimately incorporated into the FSAR. And being part of the FSAR, it is subject to -- to all of the requirements in terms of changing the FSAR, 50.59, all that stuff.

So, and we also have a provision in the license renewal rule that until those things are incorporated into the FSAR during the review process that there is a separate but similar kind of thing that they have to go through whenever they change this. There is an annual update that Part 52 takes credit for.

MEMBER LEITCH: An update of the FSAR.

MR. BURTON: Of the application.

MEMBER LEITCH: Of the application.

MR. BURTON: Of the license renewal application. There is a yearly update of that during the renewal phase. Once the -- I mean, the review

phase. I'm sorry. Once the review is over and all of this is incorporated into the FSAR, then 50.71E takes over, which is the annual update for the FSAR.

So we try to cover it -- what happens -- the changes during the review phase, and then once it's put into the FSAR the normal Part 50 update requirements take over.

MEMBER LEITCH: So that Corrective Action Program is not described in the FSAR; the AMP Program is?

MR. BURTON: Yes. The Corrective Action Program ultimately -- that we're talking about now for license renewal will be put into what's called an FSAR Supplement. And there's actually a license condition to make sure that that happens, which I'll also talk about.

MEMBER LEITCH: Okay.

MR. BURTON: So we do try to have that --

MR. GRIMES: I would like to add that for the Corrective Action Program specifically Part 50, Appendix B, provides the attributes of a Corrective Action Program, and 50 -- I believe it's 50.54A describes the process by which approved QA plans can be revised and updated.

So if there was going to be a change in

trending or the root cause evaluation or any of the procedural details that an applicant uses in current operating licenses, as well as renewed operating licenses, there are regulatory requirements that monitor the effectiveness of Corrective Action Programs and provide enforcement vehicles to control those.

That's one of the reasons why we feel we can rely on one-time testing to identify conditions for which an effective Corrective Action Program can make a determination about whether future inspections or changes in procedures might be warranted.

VICE CHAIRMAN BONACA: One point, though, is of interest. You know, the Committee has often debated one-time inspection versus a periodic inspection. And this is really the key point, where the commitment to one-time inspection can be overturned in case the one-time inspection identifies, in fact, issues or problems or aging mechanisms that were not inspected.

And this Corrective Action Program, all of the elements, I mean, for Appendix B would result, then, in the -- in a change to that. It would become a periodic inspection probably with some kind of periodicity because you identify an aging mechanism

that you did not expect.

So this is an important element, a key element actually, of license renewal.

MR. BURTON: Yes, very true.

I did want to talk a little bit about the 170 RAIs that related to the Aging Management Programs. When the original application was submitted, the Aging Management Program descriptions were in Appendix A. The staff is used to seeing how each of the 10 attributes are covered in each of those Aging Management Programs.

When we looked at Appendix A, it didn't have that, or at least it didn't have it clearly broken out. And as a result, there were a lot of RAIs generated, and it actually turned out that they were very repetitive, because we had review -- specific reviewers for each Aging Management Program, and they're all beginning to ask the same question.

So that's why you have a large number of questions related to the Aging Management Programs. They were very repetitive. You didn't address the scope of the Aging Management Program. Where is that? And you had that possibly 29 times, depending on what the specific situation was.

But when we talked to them about it, they

said, "Oh, no. We actually do have it in the form that you're looking for in Appendix B," and they sent that to us, and it took care of probably 99 percent of the questions.

But one of the lessons learned that we had -- one of the lessons we learned from that was that if we can start discussions with the applicant fairly early on to get some of those kinds of questions out, all of these probably could have gone away.

And what you'll see in some of the applications that are being reviewed now, after Hatch, you'll find that now there is a very early engagement with the applicant to start to ask some of these fundamental questions in terms of, where is this, am I not -- I'm not seeing it where it's supposed to be, is it somewhere else, dealing with some of these navigational issues. So that was one of the lessons we learned from that.

MEMBER LEITCH: Butch, I think that the ACRS members, at least certainly me, found that our review of Hatch was somewhat complicated by the functional approach rather than the system approach.

I'm wondering, after all was said and done, what you felt about that. Should we be trying to discourage the functional approach, although it --

you know, it finally worked out okay. But are there others in the pipeline that are using the functional approach? Could you give us some perspective on those types of things?

MR. BURTON: Sure. I guess, first, let me say that the second BWR to come through is Peach Bottom, and it's in-house now and being reviewed. They did not take that approach. I think initially they were going to, but when they saw some of the challenges that the staff was encountering with it I think they went back and rethought that.

I will say this. Obviously, I don't know, it's certainly possible that another applicant may choose to do that. It was a challenge for the staff, because it was the first time that we encountered that. But I think when all was said and done we learned a lot from going through it.

So if we do get another application that uses a functional approach, I think the staff is much better prepared to deal with that. Obviously, we can't tell them how to package their application necessarily, but I think that the industry who tends to watch -- those in the pipeline watch what's going on now, and I get the sense that the general consensus is that they will probably stick with a system

approach as opposed to a functional approach.

But if a functional approach comes in, the staff will deal with it, and I think we probably are better able to do it now than we were in the beginning.

MR. GRIMES: Yes, I will -- I'd like to point out that the vehicle that we've used to try and discourage excessive use of the functional approach is the standard form and content for a license renewal application that is reflected in NEI 9510, Revision 3.

And we also explored this during the demonstration project on how to improve the efficiency and effectiveness of the review process. And I think simply a reflection on the excessive level of effort required to work our way -- work our way through this review is a sufficient motivation for future applicants to pursue a more efficient packaging.

I will say that we are encountering some difficulty with the Peach Bottom review by virtue of boiling water reactors have overlapping system capabilities that tend to make it difficult to identify -- distinguish between system-intended functions and component-intended functions.

And so there's still more to be learned in terms of packaging commodities and being able to

clearly identify the relationship between intended functions, the components that are relied on, or the systems, and then the associated aging effects and Aging Management Programs.

But I do think that the industry and the staff both have learned a lesson from this experience, and we'll continue to work towards identifying ways to make the review process more transparent.

VICE CHAIRMAN BONACA: Yes. I think, you know, it goes beyond -- the review process goes -- as we said, an interested member of the public would be -- I think it's an important issue because, just to illustrate that, I mean, you may have a CCS system, and you're looking for what components in the CCS system are in scope.

And you find that maybe high pressure injection pumps are not there on the PWR, and the reason is that they also maybe perform a containment spray function. So, therefore, they've put under containment. So you are looking for CCS systems and you don't find them, and the first assessment is that a licensee has not included those components in the scope.

And then, if you search enough, then -- or you get a response, you know, you get information. So

I think that's an issue that needs continued attention, because it makes it hard for anyone who looks at the application to understand what is in scope and what is not. And it leaves a reviewer with the question mark of, what is there that I cannot possibly trace that is not in scope and should be in scope. So it's an important issue.

MR. BURTON: I do want to say one thing about Southern's application, because I know that they have -- people have had very strong comments about the format and things like that. But I think it's important to understand at the time they were putting their application together, a lot of the license renewal infrastructure had not been fully developed the way it is now.

And, in fact, you know, they had been encouraged to try and think sort of out of the box in terms of unique ways to package and bring it in. And I don't think anybody anticipated that we would converge so quickly with GALL and the standard format for the application in the SER. And so to some extent, Southern kind of got caught in the wake of all of that.

But it really was very unique. It showed some out of the box thinking. I think in that

respect, it was actually very good. I know for the staff, in terms of some of the navigational issues that came up, it really challenged us a lot, and I think we learned a lot from it.

VICE CHAIRMAN BONACA: Yes. I didn't intend my comments as a criticism of Hatch at all. They were caught in the -- I just mentioned it as a criticism of the type of project.

MR. BURTON: Oh, sure. Sure.

Okay. The next few slides I'm going to talk about some of the inspections that we had. The first one, not really an inspection, it's the scoping and screening audit that I talked about before. We went down to the applicant's offices in Birmingham for a week to go through their methodology.

Some of the things that we looked at, we looked at the exemptions of which there were 32, we looked at the design basis events, and for the design basis events they had just recently put in an update to the FSAR, something called a nuclear safety operational analysis, which really just discussed primarily their design basis event. So we had a nice, clean document to look at.

We looked at Commission orders, of which there were 28 from 1974 through '98. And we also

looked at some of the implementing procedures, and I want to talk about that a little bit.

But what we were trying to do there in looking at some of these things was we wanted to look at some of the source documentation and see what kind of commitments have they made over the years, and what structure, systems, and components are they going to have to have to ensure that they meet those commitments, and were they, in fact, identified. And we found that, going through that, that they did, in fact, identify all of the necessary SSCs.

One of the things that we looked at were -- and I think this gets to one of your questions earlier -- was when you look at this, how is that actually being implemented? We know what -- the description of the methodology that's in the application, and we know what's required in the rule. But how do you actually implement it on the ground for the reviewers?

And when we looked at the implementing procedures versus our understanding of how they institute the methodology, we found some discrepancies. And what we found was that the implementing procedures were more goal-oriented, this is what you should wind up with, as opposed to saying

-- telling a reviewer, "You need to do this, then this, look at that," you know, those kinds of things. We were looking for something a little more prescriptive.

So we were faced with a situation where the methodology, as it's described in the application, says one thing, and it looks good. But now when we look at the implementing procedures we're seeing something a little bit different. How do we resolve that?

So, in fact, what we did was we actually took three systems and actually sat down with the engineers and said, "Okay. Start us from the source documents and walk us all the way through and explain to us exactly what you did." And we went through those -- I think it was standby liquid control, HPSI, service water. I think those were the three.

So we actually sat down with them from the source documents all the way to the results, and what we found is that what they actually did was as described in the application and met the requirements of the rule.

But out of that, because we found a problem with the implementing procedures, we developed an RAI requesting them to revise the procedures so

that it reflects what's actually done. And in response to that RAI, they said that they would update the procedures. They even gave us a date certain -- September 11th of 2000 -- that they would have that done.

And it turned out that September 11th just happened to be the first day of the scoping inspection. So one of the things that we did as part of the scoping inspection was to go back and look at the implementing procedures to make sure that they were, in fact, updated. And they were. So that was just an example of some of the things that we found during the audit.

Okay. I just mentioned the scoping inspection. That was a week-long inspection at the plant site. During that inspection, we wanted to see how the commitments that they make are actually implemented on site. And that was our first introduction to their -- what they call -- I think they call a commitment tracking system, their commitment tracking system.

And what they do is all the commitments that are identified in the application and identified in the -- in our safety evaluation they put into a matrix, and you can follow that matrix from the

commitment down to the actual implementing procedures on site.

And we actually followed that through, and when we looked at the implementing procedures they actually had redline strikeout versions that had not been implemented yet, because you have to -- you know, we have to -- they have to wait until all of this is approved. But they had redline strikeout versions basically ready to go.

So, obviously, at this point, when we were doing the scoping inspection, our goal was not to make sure that everything was -- everything that ultimately should be in there was in there, but we wanted to make sure that they had the process right.

And, in fact, they did. And, actually, when you look at it, they were actually much further ahead than some of the previous applications with regard to the actual implementation of their commitments. So we were -- we are pretty pleased with that.

MEMBER LEITCH: At the procedure level, do you happen to know if they have a system that prevents those commitments from being inadvertently written out of the procedures in the future? I know that some plants have like a margin note or something, so that

it indicates that this particular part of the procedure is a regulatory commitment and cannot be just --

MR. BURTON: Right, yes.

MEMBER LEITCH: -- in advertently written out of the procedure by a future revision to the procedure.

MR. BURTON: Yes, I understand your question. And we have Ray Baker from Southern Nuclear I think can probably answer that succinctly.

MR. BAKER: My name is Ray Baker. I'm the Project Manager for the Hatch application. And, yes, you're right. There are some plants that actually do a marginal notation in the procedures themselves. That's actually a good way of doing it, I think.

Hatch is currently looking at doing that, but our process today is to maintain a commitments database or a commitments matrix, and the administrative control procedures require a person who is reviewing a procedure for change to access the database and make sure that any changes that he makes to the procedure will not invalidate any commitment, whether it's a license renewal commitment or other Part 50 commitments that have been made. And so that's the current process.

MEMBER LEITCH: Okay. It does the same thing, just a different way.

MR. BAKER: Yes, sir, that's right.

MR. BURTON: Okay. Our third trip to Southern Nuclear was for our aging management review inspection. When we go down for the aging management review inspection, now we're focusing on the Aging Management Programs and whether they are, in fact, written, and some of the supporting documentation on site actually gets to the applicable aging effects that it claims to manage.

We did another -- took another look at the commitment tracking system, this time focusing on the Aging Management Programs and how the commitments were tracked. And, again, we concluded that they were being tracked appropriately, that they had actually captured everything that they needed to capture.

We had a final inspection, just a couple of days. This final inspection is optional. It's really sort of a cleanup if there are any outstanding issues that we may need to check in -- that we identified previously that maybe need to make sure that are properly followed up on. We take a couple of days and go down and do that. Again, we found that everything -- any final questions that we had they had

taken care of.

Okay. Next thing, wanted to talk a little bit about some open items. First of all, in terms of summary, in our SER we had 18 open items that were identified. Twelve of them were resolved without appeal. Six of them went through the appeal process. And, you know -- and I can -- I'll be talking about at least a couple of those later on.

One of the issues -- and I brought this up primarily because this was brought up a couple of weeks ago with the subcommittee -- had to do with buried components. What we have is a one-time inspection of the buried fuel oil storage tanks, and that was one of the open items.

And what Southern Nuclear had done was they were -- had actually looked at one of the four buried tanks. These are huge 40,000-gallon tanks. They had actually done -- gone in and looked -- done some ultrasonics and stuff like that on one of the tanks, to look at the tank bottoms to see if there was any age-related degradation.

They took advantage of the opportunity of being in the tank to do that and found none. They took that experience and said, "Okay. Well, the other three tanks, same material, same environment, they've

been buried for the same period of time. We think that the results that we saw in the one are applicable to the other."

The other thing was that there was -- there are also fuel oil tanks for the diesel-driven fire pumps. These are much smaller. They're above ground. You can just go and look at them any time. And so because they are the same material in -- the environment was even more benign than the environment of the buried tanks, we felt like the condition of the buried tanks bounded those for the fire pumps. So that was how we had resolved that one.

A couple of weeks ago we got into a discussion of, what exactly do you do in terms of managing the tanks? What do you do if there, in fact, is some leakage of those big tanks? It's underground. You can't see it. What's the safety consequence of that?

First of all, the interior of the tanks are inspected via tech specs. What they have in their implementing procedures, one of the things that we looked at when we went down there was as part of their -- the implementation of their Structural Monitoring Program they have excavation procedures that direct them to -- if you're digging up and around that tank,

go and take a look at the coatings, because the tanks are coated.

And there's a protective coatings Aging Management Program that gives them all of the details of how to do that. So that was how that was taken care of.

MEMBER FORD: Could I just ask a question on the --

MR. BURTON: Sure.

MEMBER FORD: When you said that there's an Aging Management Program for the protective coatings, for instance, to what depth does your staff go to examine whether those programs are adequate technically?

MR. BURTON: Okay. And I don't know all of the technical details, but I think I've got my guy here, Jim Davis, who can --

(Laughter.)

-- speak to that.

MR. DAVIS: I was actually on the NISC Committee that wrote the underground coatings specification for the Department of Transportation, and I reviewed this. There's quite a bit of difference in what they do and with what you'd have to do with an oil or gas pipeline or a tank on ground.

But we looked at the program, and we've negotiated with NEI and the industry, and we have an alternative program that we find is acceptable. And that is the UT measurements on the bottom of the tank to make sure that there's no corrosion due to the soil and no corrosion due to water being on the bottom of the tank.

For buried pipe, we had a lot of discussion on all of the applications. And, basically, any time they dig the pipe up they're going to examine the pipe.

In addition to that, they're not taking credit for what they're doing. In a lot of cases they have some -- some of the utilities have Cathodic Protection Programs and they do the pipe-to-soil potential surveys, which is what the standards tell them to do. But they're not taking credit for that because the equipment was not purchased safety-related.

So they have a program that they're not taking credit for, and they have a program whenever they dig up the pipe they look at it, and they're taking credit for that for aging management.

MR. GRIMES: And, Dr. Ford, I'd like to add to that that in general all of the technical staff

used the 10 attributes of an effective Aging Management Program in order to decide, as Dr. Davis pointed out to -- these negotiations that he referred to are basically identifying what is necessary and sufficient for any one of the attributes, the 10 attributes. And that is what we referred to as our basis for concluding that the program is technically effective.

MEMBER FORD: The reason why I'm picking it up is, as I mentioned at the last meeting, I don't doubt that what you've said is correct. It is in the public forum that we made it clear that that has been done.

MR. GRIMES: And to the extent that we continue to look for ways to enhance the Generic Aging Lessons Learned that constitutes the compendium of what attributes we feel are necessary and sufficient for any one of the programs, and those areas where the staff feels that the 10 attributes might not be clear, or might have some plant-specific variability and want further staff attention.

CHAIRMAN APOSTOLAKIS: Chris, you really mean only sufficient, not necessary and sufficient, right?

MR. GRIMES: I mean necessary and

sufficient.

CHAIRMAN APOSTOLAKIS: Really?

MR. GRIMES: To the extent that -- yes, the -- there are -- those things that we feel are really needed in order to be able to defend the effectiveness of a particular program and manage the applicable aging effects.

And in some cases we, in the industry, got into long and heated debates about whether or not particular attributes like trending -- you know, when is trending needed for things that don't occur on a frequent enough basis to establish a good trend. So we did want to really come out and say, "What are those things that are really necessary for an effective Aging Management Program, as well as what is sufficient for the purpose?"

That's the standard that we use in order to ensure that we're achieving our -- the agency goal of not -- of avoiding unnecessary burden.

VICE CHAIRMAN BONACA: Could you put back the previous slide? The last bullet you say that continually inspected the -- via tech specs. What does the inspection consist of that's not -- I mean, we are talking about here a one-time inspection of buried fuel oil storage tanks --

MR. BURTON: Right.

VICE CHAIRMAN BONACA: -- from inside.

MR. BURTON: Right. What --

VICE CHAIRMAN BONACA: That is not repeated.

MR. BURTON: Yes. One of the things that we talked about last week, one of the questions that you had was, what's normally done with these tanks in terms of, you know, going in and taking a look and stuff? And what normally is done is they go in and they clean the tanks periodically, and stuff like that.

Normally, what they do is they take advantage of that time to go in and look around, see what evidence there is of age-related degradation, things like that. I don't know if you guys wanted to add anything.

VICE CHAIRMAN BONACA: That's a visual. I mean, that's just a visual inspection.

MR. BURTON: Right.

MR. PIERCE: Yes. My name is Chuck Pierce of Southern Nuclear. I think what Butch is referring to up there when you say interior inspected via tech specs, just to add a little bit to that, is we have provisions in the tech specs to check the tanks

monthly to make sure that they -- for level, and there are ways that -- we have both Control Room indication and we can go out and take a dipstick and check the tank monthly for level and see if there's any change in level and deal with any leaks from that perspective.

VICE CHAIRMAN BONACA: Yes. This is important because, I mean, during the subcommittee meeting we had the discussion regarding the acceptability, and the concern was possible external damage that may result in doing installation that may have caused the coating to be fractured or broken, and, therefore, corrosion to come in from the outside.

And two points were made. One is that that would be a concern also with the current license term and not necessarily just specific to the license renewal.

And, second, we looked at the -- these are not the day tanks. We asked specifically that question. These are the backup tanks, and that if, in fact, a leak developed, there will not be a significant safety concern because it would not lead to significant depletion of inventory of fuel before -- to prevent any safety function, you know.

So that was one consideration that the

subcommittee discussed, and I believe we had some kind of concurrence on that perspective.

MR. BURTON: Yes. We --

VICE CHAIRMAN BONACA: So we are going back to the meaning of the rule when it talks about 70 systems, support systems that support the safety function, and so on.

MR. BURTON: Right. Okay. Next thing I was going to talk about was fire protection a little bit. And, actually, for fire protection let me go back to scoping for just a second. As I'm sure you all are well aware, fire -- the licensing basis for fire protection systems, they vary widely across the industry. There have been so many exemptions that people have taken.

And so the cumulative benefit of doing reviews that we normally get for most systems we don't get as much for fire protection because they are so -- they are so unique so many times. So what we've found is that when we're doing the scoping we find that we've got to get our fire protection engineers involved and digging down into the licensing basis pretty early, looking at the fire hazards analyses and, you know, some of the commitments there, to see what exactly is necessary to meet 50.48.

So we -- that is one of the lessons learned is that to get our fire protections -- fire protection engineers in there early to start looking through these. And, in fact, for Hatch we had -- we had folks down there looking at fire protection both at the audit stage and at the scoping inspection stage, doing some walkdowns and things like that.

So from a scoping perspective, fire protection is somewhat unique in that we really have to hit it early.

In terms of aging management fire protection components, there is a separate Aging Management Program for that -- fire protection activities. One of the things that came up a couple of weeks ago had to do with aging management. There wasn't an issue with some of the other components in the system, but there was an issue with what -- how they managed the sprinkler heads.

And what that issue was is that we asked them to follow the guidelines of NFPA-25. NFPA-25 says that sprinkler heads need to be looked at after 50 years, and then again at 10-year intervals. And given the fact that we're now looking at plants that are going to be operating for 60 years, how does all that play out?

And that actually came up as an issue for the staff, and then it -- we also discussed it a little bit at --

CHAIRMAN APOSTOLAKIS: What's the basis for the 50 years?

MR. BURTON: Okay. And that was one of the questions. One of the things -- and we have since gone back and actually tried to take a look at that. The basis for the 50 years came from a statistical study. I have the information right here. What they did was they looked at 3,000 sprinkler heads, and they've traced these over rolling 10-year intervals to look at the degree of age-related degradation.

And what they found statistically is that heads that were in use for 55 to 60 years had only a two percent failure rate. And those who -- those that were in service for 40 years had a 1.8 percent failure rate. So given those numbers, I guess it was engineering judgment that said, "Look, I think we can be pretty confident that these things will operate for about 50 years without suffering an extensive amount of age-related degradation based on these numbers." So it was really based on a statistical study.

CHAIRMAN APOSTOLAKIS: So they have a failure rate of 1.8.

MR. BURTON: For 40 -- over 40 years.

CHAIRMAN APOSTOLAKIS: 1.8 what, percent?

MR. BURTON: 1.8 percent of the sprinkler heads.

CHAIRMAN APOSTOLAKIS: So two percent.

MR. BURTON: Roughly two percent.

CHAIRMAN APOSTOLAKIS: Times 40. That's 80, right, .8 probability of failure in 40 years? Is that what it is?

MR. BURTON: I don't think it was roughly two percent per year. I think it was roughly two percent cumulative over the entire time. You're going to ask me a lot of details about the study I don't really know, but --

CHAIRMAN APOSTOLAKIS: I'm just curious how these --

VICE CHAIRMAN BONACA: It makes a big difference.

MR. BURTON: Yes, that's a big difference. I would think if it was the kind of numbers that you said, they probably wouldn't go with 50 years. But that's --

VICE CHAIRMAN BONACA: Well, you go with the explanation of distribution, multiplying straight, you know --

CHAIRMAN APOSTOLAKIS: Well, I think it's 1.8 and --

MEMBER FORD: When this question came up at the last meeting, essentially we made the observation that 50 years is unbelievable, from a knowledgeable public's viewpoint, with their cars, etcetera, etcetera, etcetera.

Dr. Davis gave a very good corrosion engineering explanation as to why it's not unreasonable, and your statistics can bear that out. However, the arguments that are made are dependent very much on maintaining a specific environmental material, environmental system.

MR. BURTON: Absolutely.

MEMBER FORD: How sure are we that that has been maintained at Hatch?

MR. BURTON: Okay. Good question. And, in fact, what Dr. Ford is saying is true. The study that I refer to does say that these numbers are good assuming that you have good maintenance, good inspections, all those good practices.

MEMBER FORD: Adherence to certain corrosion criteria.

MR. BURTON: Right. And what you will find is that some of those conditions that back up

these kind of numbers are what you find in some of the actions that are called for in the protective action activities AMP.

MEMBER FORD: And in terms of monitoring and control at Hatch.

MR. BURTON: Yes.

MEMBER FORD: Okay.

MR. BURTON: What you're speaking to now are those 10 attributes, the detection methods, the frequency of inspection, those kinds of things. Those are the 10 attributes that we look for for all of the Aging Management Programs.

MEMBER FORD: Maybe I'm misreading that second sentence that you have there. It's saying essentially that it hasn't been looked at, and it won't be looked at until 50 years.

MR. BURTON: Oh, okay. Well, yes, maybe I --

VICE CHAIRMAN BONACA: But the system is tested.

MR. BURTON: Oh, yes. Yes. In addition to the normal system testing, right.

VICE CHAIRMAN BONACA: What is the frequency of testing?

MR. BURTON: Again, I don't know the

details of that. I don't know if --

VICE CHAIRMAN BONACA: Over here, is that the frequency?

MEMBER POWERS: I mean, the fire protection systems each year get 35 hours worth of inspection in the normal program. And what they're specifically looking for is degradation in both the automatic and the manual fire-fighting capabilities.

There is, in addition, a triennial inspection that's looking more at the safe shutdown capabilities, but included in that is the ability to keep one train of shutdown capabilities free of fire damage. Where the licensee has relied upon automatic suppression, as part of a campaign to keep one train free of fire damage, they would look at that suppression capability every three years.

MEMBER FORD: Okay. So the communication that's given by that second sentence is misleading.

VICE CHAIRMAN BONACA: If it implies that it is a first inspection, absolutely, yes.

MEMBER POWERS: Typically, on the -- the challenges that you have with sprinkler heads is the activation mechanism of them, because they can't be located close enough to a ceiling, just by where they are. And various mechanisms are done to make them

effective, and that includes things called heat collectors and things like that, which nobody knows if they really work. In fact, they may work the wrong way.

But, I mean, it -- I mean, these things are looked at. I mean, and people agonize over them at some -- to some great extent, because they are part of a major feature of the plant safety.

VICE CHAIRMAN BONACA: Actually, though, it is important to note that this inspection here, the first one, is intended to be actually either a replacement of the head, straight number -- 50 years you replace the head, or you inspect it closely enough to determine that it is still performing as good as it should.

CHAIRMAN APOSTOLAKIS: How is it different from a test? Maybe this is --

MR. BAKER: Dr. Apostolakis, the NFPA-25 test that -- inspection that's referred to here is a destructive examination of a sample of sprinkler heads that's in addition to the normal fire protection aging management activities.

So this is -- this is an ultimate verification, if you will, after 50 years that you still have sprinklers. You have confidence that the

remaining sprinkler heads of that type will, in fact, perform as intended.

MR. GRIMES: I'd also like to add -- I was wounded slightly by Dr. Ford's statement that the second bullet was misleading. It's a factual statement. NFPA-25 recommends sprinkler head inspections after 50 years. We frequently refer to industry standards as having particular provisions. But embodied in that particular factual statement is a reliance on a whole host of plant preventive maintenance and inspection activities, housekeeping methods.

There's a panoply of stuff that underpins our particular reliance on a standard. If we say we rely on the ASME Code, you know, we trust that you'll understand there's a whole lot more to the in-service inspection program with respect to maintenance of the environments or, you know, preventive maintenance of the plant condition.

So we didn't intend to be misleading. We just intended to refer to -- that was the underpinning of the resolution of this particular issue.

MEMBER FORD: I guess I'm showing the lack of my knowledge. But as an informed member of the public, if that's the only information I had, I'd be

worried.

CHAIRMAN APOSTOLAKIS: I wonder whether you are hurt, too.

(Laughter.)

VICE CHAIRMAN BONACA: Just one piece of information we received in the subcommittee meeting was that the 50 years, it's -- does not refer to -- from the day of start of operation, but it refers to the day of installation I guess. And for this plant, I believe that the 50 years will come three years into the license renewal term.

And, you know, that gave us some comfort, that at least at the beginning of the license renewal term, or close enough to that, we are going to have a distraction --

CHAIRMAN APOSTOLAKIS: The point is that these inspections give you a lot of information. You are collecting information through the tests.

VICE CHAIRMAN BONACA: Yes.

CHAIRMAN APOSTOLAKIS: So that's really an important point. I mean, it's not that they're looking at them for the first time in 50 years.

MR. BURTON: And thank you for the clarification, Dr. Bonaca, because I was going to make a point that that 50 years is not 50 years of plant

operation, but 50 years from the time the system is declared operable.

VICE CHAIRMAN BONACA: So, evidently, that has been installed for seven years before the plant went to power.

MR. BURTON: Right. Exactly. Okay. I guess I'll have to rethink this slide. Okay.

CHAIRMAN APOSTOLAKIS: So since NFPA-25 says it, it must be right, right? It's in NFPA --

MR. BURTON: Well, I --

CHAIRMAN APOSTOLAKIS: Or you don't know about the NFPA-25 -- that's okay.

(Laughter.)

MR. BURTON: You caught me on that one. I don't know what to say. Yes.

A couple of the other open items that we have talked about were -- had to do with postulated pipe breaks and cast austenitic stainless steel components; specifically, the jet pump assemblies and fuel supports. One of the open items that we had developed and that did go through the appeals process had to do with whether or not postulated pipe breaks should be considered a time-limited aging analysis.

And the way that works is that the cumulative usage factor for fatigue is part of what's

considered in identifying locations for pipe breaks, and it itself is a TLAA. And so the question was, well, if that is, shouldn't this be also? That was point one.

The other point was that in our statements of consideration it called out postulated pipe breaks as being one of the things that should be considered a TLAA. Southern Nuclear felt that that was something that didn't necessarily need to be considered as a TLAA, and that was taken through the appeal process, which I'm going to talk about in a few more slides.

And in the end, we decided that, yes, it probably should be considered a TLAA, and that resolved the issue and they gave us all the supporting material that we needed for that.

Another one had to do with cast austenitic stainless steel components. The question was whether there needed to be a one-time inspection of these components. The staff's initial position was that there probably should be. We went -- again, this was also taken through appeal, I believe. I believe this was one of the appeal items.

And it was decided that rather than looking at the components themselves, which industry wide have actually shown no evidence of cracking, for

those inspections that have been done, that, rather, we should probably look at focusing on the welds. And one of the BWR VIP reports, VIP-41, actually gives guidance for the inspection of some of the welds.

And so the idea was that the welds would probably be a precursor to cracking in the components. So as part of the resolution, we said, "Okay. We're not going to ask for a one-time inspection there. We'll let the inspections of VIP-41 of the associated welds be the precursor for that."

MEMBER FORD: Butch, again, at the meeting we had a while ago, this also came up with quite some discussion. The question being as to whether the inspection of another component is necessarily a precursor to failure of these components.

MR. BURTON: Right.

MEMBER FORD: Given that you've got a different material, maybe a different degradation mechanism. And we were rather put at ease by the statement that there was going to be a research program on this topic.

Could you just give very, very quickly some idea of the timeliness of this research program? When will it be completed, to support this conclusion?

MR. BURTON: Okay. Sure. And let me just

say very quickly is that, yes, one of the things that we talked about was having some joint research done between the BWR VIP and our Office of Research to just -- just to confirm that -- whether or not doing inspections of these components really is warranted.

And, actually, I have my BWR VIP guy here, Gene Carpenter, who can speak to that. So --

MR. CARPENTER: Good morning. This is Gene Carpenter from Materials Chemical Engineering Branch. Yes, we are looking into the possibility of doing some joint research, as Butch was saying. At this time, we have not gotten that onto the schedule for research to be conducted in fiscal year 2002 or 2003.

We are planning to have it at some time in the very near future, hopefully to run for a period of no more than three years, at which time we should have some additional information to make determinations as to whether or not any inspections will be necessary in the license renewal term.

MEMBER FORD: So it could be six years before you have any data at all to confirm this assumption.

MR. CARPENTER: But that is still before Hatch will go into a license renewal term.

MEMBER FORD: That is true. I've got one other question. I think this is your last slide on AMPs, is it not?

MR. BURTON: Yes.

MEMBER FORD: There was another question brought up about stress corrosion cracking of high-strength bolting.

MR. BURTON: Yes.

MEMBER FORD: Which is one of the open items. And it was put to rest as far as Hatch was concerned in that inspection of the bolting indicated no problems, and that they were all below the 150 KSI yield point, which is generally attributed to cracking of the high-strength components. It's pure luck, however, that it was below 150, because there's no upper specification limit.

This question has nothing at all to do with Hatch. It's more of a generic question. Since there is not an upper specification limit, how are we sure that this is not going to be a problem in the future? And how are you going to address that? You're really -- you're looking at it in a reactive mode.

MR. BURTON: Yes.

MEMBER FORD: Rather than a proactive

mode.

MR. BURTON: Yes. I understand what --

MEMBER FORD: For replacement bolts, for instance, or whatever you might do.

MR. BURTON: Okay.

MEMBER FORD: Are you going to ask that there be an upper strength specification on such bolts?

VICE CHAIRMAN BONACA: This is important also because, if you remember, we discussed this in the previous application, and we -- I was confused. I thought they were the same bolts. The licensee told us that they had limits, torquing limits, on those bolts, below 150 KSI.

And we were told by the staff that they were a different type of bolts, so that would be good for us to have an understanding of what bolts we're talking about and why in some cases you impose a 150 KSI limit on torquing activities, and in other cases you don't.

MR. BURTON: Okay. Yes. And I'll ask Jim Davis --

MR. DAVIS: Jim Davis from the staff. It's pretty well known throughout the industry about the 150 KSI limit. It's been discussed at a lot of

technical meetings, and a lot of people have those -- that limit in their specs now.

The problem is there's in the neighborhood of 40,000 studs, bolts, fasteners, in a plant, and it's pretty difficult to backfit all of those. Certain ones they know there's troubles with. These are the assay 193 B7 volts, and have a 105 minimum yield. And they've come in as high as 150-, 175,000 KSI yield, looking back at the material test reports.

What we've done is I've raised this question with every single application so far, and they'll all cited the industry experience. There's been one case of cracking, and that was at Dresden on their reactor closure studs. And those are the four-inch diameter closure studs, and they actually cracked in a very short time. They had a crack 180 degrees around, about two inches deep.

They don't crack when a reactor is in operation because it's too warm and the moisture doesn't get there and cause the corrosion, cause the damage. So there's only two cases that we've ever seen of cracking other than 410 bolts that cracked in Anchor Darling check valves.

So we've let them rely on operating experience to say that they haven't seen the problem,

and Hatch actually looked through their certified material test reports and showed that they were -- they were all under 150 KSI yield. So that's the way the industry has approached it. It's just too expensive to go back and replace all those fasteners, because there are just so many of them.

MR. BURTON: Okay. Now I'm going to go and move on to one-time inspections. At the subcommittee, we had --

MEMBER LEITCH: Just before that, if you were going to leave open items, there was one that I was assigned lead responsibility to follow up on. And I was not at the subcommittee meeting, so I -- and it had to do with housings for various fans in the HVAC system.

And I guess the question was whether they were -- I guess the licensee considered them active -- the fans were active, certainly, but whether the housing were a part of that or not, and I think staff's position was that they were really passive, long-lived components, and, therefore, should be part of a program.

I guess from reading it looked like that issue was satisfactorily resolved, and they are, indeed, going to be part of the program.

MR. BURTON: Right. Yes. I'm glad you brought that up. We had an open item having to do with housings for certain active components -- fans, dampers, things like that. They were in scope, but it turned out that Southern Nuclear decided that they didn't need to be subject to an AMR because they they were part of the active -- the associated active component. And, as you know, active components are not subject to AMR under license renewal.

The staff's position, though, was that the housings for these active components we should be treating them similar to how we treat valve bodies and pump casings, which are specifically called out in the rule and the associated statements of consideration.

The idea is that the component may be active, but the housing for that component may have a pressure boundary function, structural integrity function, something that is necessary in order for that active component to work. And as such, if that housing is long-lived and passive, and it has applicable plausible aging effects, then we need to look at that. We need to capture that in license renewal as part of an Aging Management Program. That was the staff's position.

When we looked at it, Southern Nuclear

said, "Well, no, the valve housings and the pump casings are specifically called out in the rule and the statements of consideration, and that -- and also in the guidance document NEI-9510." And that because they are specifically called out, that's all we need to deal with.

The staff's position was, no, those are given in those documents merely as examples. And when you go back and you actually read the wording, every time valve housings and pump casings are brought up in those documents, it says "for example." So the idea is that those are examples of how to treat housings.

And so our staff in doing the scoping and screening evaluation, we recognize that no, the housings for fans and dampers are also critical to making sure that that associated active component can perform its function. And that went through one level of appeal, and we -- and in the end it was decided that, yes, those housings would be subject to an aging management review and were brought in.

MEMBER LEITCH: Okay. Does that rationale apply to standby gas treatment, reactor building ventilation, control room ventilation?

MR. BURTON: Yes.

MEMBER LEITCH: All those important --

MR. BURTON: Yes. In fact, when it was brought up as an open item, standby gas treatment system, control building HVAC, outside structures HVAC, and reactor building HVAC were all captured in that open item. So, yes, it does apply.

MR. GRIMES: Dr. Leitch, I'd also like to add we learned a valuable language lesson in the resolution and clarification of the guidance. There are some plants that when they talk about the housing of a fan, they're referring to the frame, and they consider the shell to be part of the ductwork, in which case we -- the staff position would -- we would agree.

We're not looking for the frame that's holding the motor. We're looking at -- we -- our interest is the shell, as Butch pointed out. We're looking at the pressure boundary function. And so this is -- we've clarified our guidance, so that those plants that refer to the shell when they talk about the housing understand our interest is in aging effects associated with the shell, not necessarily the frame. The frame we do consider to be part of the active component.

MEMBER ROSEN: I'm left a little troubled by the discussion we had earlier about the research

program, which I take to be a research program on cast austenitic stainless steel.

MR. BURTON: Okay.

MEMBER ROSEN: In that I don't understand how the process works. If that research should show some additional aging mechanisms, how that process works to -- that would lead to the licensee being committed to doing whatever the research required.

MR. BURTON: Okay. And that's a good question. I have a slide a little bit later that discusses how we deal with new and emerging issues. And, actually, the housings issue was an example of that, and what you're saying is also. How do we get that -- the results of that into the whole process?

If you can hang on just a couple more slides, I think I can speak to that.

MR. CARPENTER: Butch, if I might, specifically for the BWR VIP program, which this is part of, that research is part of, what the BWR VIP program has in place is a commitment to the staff from all BWR owners in this country, that any activities that they have committed to -- and this would be part of a joint research with the BWR VIP, so they would make appropriate modifications to the BWR VIP-41 report, Inspection and Final Evaluation Guidelines.

They would come back at that point and revise the inspection criterion for all BWRs. So if they -- if we find in the future that we need to do additional inspections for these internal components, part of this VIP program, then it's already taken care of by previous commitments to the staff.

MR. BURTON: Okay. So --

MR. CARPENTER: But Butch will also discuss further --

MR. BURTON: Yes, I guess I don't have to talk about that part of it. And then the other part of that also is part of the BWR VIP program. It's my understanding -- and correct me if I'm wrong, Gene -- but part of the program is that the inspection results of the VIPs, as the VIPs have been instituted, that the inspection results are actually published semiannually. So that everybody who is subject to those VIPs gets an overall idea of what is going on in the industry and can deal with it appropriately.

So one of the things that we talked about at the subcommittee was one-time inspections. This idea has been talked about a lot for some of the previous applicants, but it's probably good to go through it again.

The statements of consideration for the

rule discuss when it's appropriate to do one-time inspections. And one of the concerns from some of the subcommittee members is, how can you justify a one-time inspection if it turns out that there are aging effects that reveal themselves later on?

So what we do -- first of all, one-time inspections are intended to be confirmatory only. And the idea is that when you have a commodity group, a material-environment combination, which is what we call a commodity group, if there are normally aging effects associated with that commodity, but actions have been taken such as water chemistry, to preclude that aging effect, the idea is that we're handling it, we don't expect to see anything, but what we'll do is we'll do a confirmatory inspection one time to make sure.

And as Dr. Bonaca said before, if we do that one-time inspection and, in fact, we do find evidence of age-related degradation, then through our Corrective Actions Program -- not ours -- their Corrective Actions Program, they will take that operating experience, funnel it through, make whatever appropriate changes there are to the appropriate Aging Management Programs, and it may not be a one-time inspection anymore. It may be an ongoing kind of

thing.

So that's the idea behind one-time inspections. Make sense? Okay.

MR. GRIMES: Also, and I would like to add to that, I want to remind the Committee that a fundamental principle of license renewal that the Commission noted in the statements of consideration when the rule was published, that we anticipate that operational experience in the future may reveal new aging effects that we just don't know about at this point in time. We expect to continue to conduct anticipatory research and learn more things about aging effects.

The regulatory process provides a means for us to reflect on that and to identify what corrective actions we feel should be taken across the whole of the industry. And it is founded on that principle that the Commission continues to have that process, so that we can rely both on the licensee's Corrective Action Program to identify plant-specific experience that warrants a change in Aging Management Programs, or the Commission's generic communication process can identify actions to be taken on a generic basis.

And for that reason, we don't need any

special commitments to go look for aging effects that we do not yet know about. And so it is important that we be -- that we be able to rely on the regulatory process to continue to learn and evolve and react, and that is what -- why we are comfortable with the concept of one-time inspections and the capabilities of the corrective action processes to appropriately maintain the licensing basis starting 10 years hence, way off in the future.

MR. BURTON: Okay. Next thing I wanted to talk about was the appeal process. We have technical differences of opinion with applicants. It happens. And it's important that we have a reliable, transparent, predictable way of resolving those. Another aspect is from a public visibility point of view it's important for public confidence that people understand what we do and how we do it. So we've developed this appeal process.

But I think one thing that's important to understand is that what we do -- Hatch is not the first one to have to deal with resolving these kinds of technical issues. We've been doing this right from the beginning. The difference is that we've tried to formalize the process, again, for visibility, transparency, public confidence.

Let me -- I'm going to jump back and forth a little bit here. Let me show you the flowchart for how we do this. I know that's hard to read. But, basically, if we get a difference of opinion on an issue, we start it through and what we do is we escalate it -- hopefully, we resolve it at the first appeal.

If we don't, it starts to get escalated up through higher and higher levels of management, both management -- staff management and applicant management. So both sides get to see what's -- exactly what's going on.

In the case of Hatch, we had issues that were appealed first level, at the branch chief level, and a few that went to the division director level, but at that point we got everything resolved. So I think -- which is -- we kind of went down through I think right around in here. I think that's as far as we got in the process.

And, of course, as we go through we document everyone's position. We document the resolution and the basis for the resolution. And we incorporate all of that into our safety evaluation.

So we had -- as I had mentioned before, we had six items that went through appeal. I can't

remember how many were resolved after the first level and how many went to the second. But we did have six items that went through appeal.

Let me go back to this now. Actually, this just says what I already said. If we can't resolve it at the working level, it's escalated up through management, and management does hear the technical arguments on both sides. Because this was the first time that we went through it in such a structured way, as with anything else, we found ways that we could improve the process.

Southern Nuclear had provided some comments and suggestions on how to improve the process. And one of the things about the license renewal infrastructure is we do have processes in place to capture those lessons learned and ultimately incorporate them either into the review guidance or the specific staff guidance for how we do what we do. But our infrastructure allows us to capture those lessons learned. So -- and the appeals process is no different.

Okay. Next thing, treatment of emerging issues. And Gene already spoke specifically about how things that are discovered, as far as BWR VIP, gets factored in. But it's more than that.

The first thing is issues are always being identified. I don't think there has been an application yet where we have not had something, okay, and so obviously we realized later on very quickly we need to disposition those in a very predictable, very transparent way.

When we do that, as we resolve an issue, there are several things that have to be taken into account. Not only how it's resolved for that particular applicant, we've got to understand how it's going to be addressed for those who come after, and how -- does it need to be addressed for those who perhaps already have their license.

Okay? So we've got to look at all of those. And for those who come after, the -- you can actually break them into two groups. Those who come immediately after haven't had an opportunity to incorporate the resolution into their application. So we've got to disposition that through RAIs and perhaps open items and things like that.

For those who are a little bit further out, who still perhaps haven't put their applications together, they have an opportunity to incorporate those. And, actually, that's exactly what you've seen with much of the work with GALL. The plants coming in

in 2002 are the GALL plants. They were far enough out that they can incorporate all of the resolutions for GALL.

Those who came in before that at -- such as Hatch, Hatch did not have the opportunity and the benefit for all of that. So some of those things have to be dispositioned in a separate way. But part of our treatment of emerging issues is to take all those into consideration.

Another example is seismic two over one, which I'm sure you all are familiar with. You've seen that in the SER.

We resolved that. Right now, we developed a set of RAIs for those immediately after to start getting their arms around it. For those further out, we expect that to be dealt with in their application.

Go ahead. I'm sorry.

VICE CHAIRMAN BONACA: Realize, however, the comment we made regarding -- we raised some issues regarding how do you provide this guidance to future applicants, was more pointed to the fact that this SER, more than previous ones, had significant clarifications inside them.

For example, seismic two over one, there is a discussion on a couple of pages in which the

discussion of preventative versus mid-event, again, it is clearly laid out. And now there is a logic there that makes sense on why certain components should be in scope.

And that's very important discussion that I think, you know, we don't want to have it just lost into page X of one specific SER. I think that if it is provided in some guidance format, it will prevent future open items.

MR. GRIMES: That's correct, Dr. Bonaca, and I would like -- I'd like to address that. By making a distinction between emerging issues and process improvements, which has described the way that -- as issues come up, we established staff positions. We've determined solutions. And for issues like the treatment of non-EQ cables, which emerged in the middle of the Calvert Cliffs review, we identified an aging management solution for that that ultimately was captured in an explanation that was incorporated into the Generic Aging Lessons Learned Report.

Taking a slightly different tact in terms of seismic two over one, or an issue that we're about to bring to the forefront on scope of station blackout equipment, where there was -- where we discovered that there was a miscommunication or a misunderstanding

about the true nature and extent of a particular commitment related to resolution of either scope or an Aging Management Program.

The process that we followed before the institution of the improved renewal guidance is the same process that I would expect to follow after, and that is we'll send a formal letter to the industry and to the interested public advocate. In this case, I'd use Mr. Lochbaum to represent the public interest.

We send a position to them and say that we've clarified a staff position. We open a dialogue with our stakeholders in terms of making sure that we've actually achieved the desired shared understanding.

And then we'll pull that back into a decision on where that should be appropriately reflected, whether it's in NEI 9510, whether it's in the standard review plan, whether it goes in Generic Aging Lessons Learned, or there is even a fourth category and that is that both the industry and the NRC staff maintain what we refer to as style guides, and that is common language use that doesn't really rise to the level that dictates the need for any kind of formal procedure. It's just a collection of good practices.

And so we would expect to continue to do that, and, in fact, we intend on submitting the more detailed explanation of seismic two over one to the industry to pursue a generic dialogue with them to settle any more misunderstandings that we might have.

And then to -- and that then will become part of the collection of things to do to further improve the guidance. And I know that you want me to commit to a date certain for the next revision of that guidance. But, quite frankly, I've only got two examples, so far, and I don't think two changes warrants a reissuance.

But it could be that by the time that we get the 2002 applicants that we'll have a dozen or so further lessons from the class of 2001. And at some point we'll reach a collection that's large enough to warrant formal revision. But in the meantime, I have committed the industry that we're going to find a place to exhibit these clarifications, so that future applicants and the ACRS and the public will see the additions to the guidance as they're unfolding.

VICE CHAIRMAN BONACA: Thank you.

MR. BURTON: And I did want to add that as part of the -- when we inform the industry of the staff position and we start that dialogue, that that

process does include the appeal process if there are significant differences to resolve them through the appeal process.

Okay. Coming down towards the end. As a result of the staff's review, we identified three license conditions. The first two are standard. The first one -- I mentioned before that there is an FSAR Supplement. It's a summary description of all of the activities and programs that they are crediting for license renewal. That supplement has to be incorporated into the FSAR at the next update following issuance of the license. We capture that as a license condition, and that's standard.

The other thing is that in those Aging Management Programs there are a number of things that the applicant says that they're going to do before entering the extended term. We capture those commitments as a license condition -- again, pretty standard.

There is a third license condition that we have for Hatch that has to do with the reactor vessel Integrated Surveillance Program. This is one aspect of an Aging Management Program called reactor vessel monitoring. One of the aspects of that is that you're going to have a Surveillance Materials Testing

Program.

At the time that the application was submitted, we had in-house BWR VIP-78 that -- they were saying that the actions in that BWR VIP, those are the actions that we're committed to taking for the capsules.

We had not finished our review of that. Okay? So we couldn't just bless it. So what they committed to was they said, "We'll do VIP-78, or, if for some reason that's not acceptable, we'll institute our own plant-specific program, because they have their own capsules."

And so -- and they detailed exactly what actions they would take, so we have a license condition that says you need to inform us which of those two you're going to take. So we have that third license condition.

MR. GRIMES: Butch, if I may, before you leave the license conditions, I want to respond directly to the concern that Dr. Rosen raised before in terms of in the case of the BWR VIP, there's a range of commitments that go along with that.

And the staff didn't specifically point to the associated research activities that Dr. Ford drew comfort from for CAS. We identified an aging

management practice that we concluded was acceptable with surrogate inspections.

The research program provides added comfort. And it does get captured as a commitment, along with all of the other commitments, for program descriptions that will be included in the FSAR that can be managed pursuant to 50.59.

The Integrated Surveillance Program, however, didn't have the benefit of the commitments. It, in fact, was a promise to develop a program in the future for which we needed to call it out separately as a license condition in order to ensure that that program would achieve all of the necessary program attributes.

So it gets treated different from all of the other commitments that are simply referred to or articulated in the FSAR.

MR. BURTON: Last slide. And I'm ending where I started. 10 CFR 54.29 outlines the criteria to determine whether or not it's okay to grant a renewed license, the three bullets that you saw at the beginning of my presentation. Hopefully, after the presentation you have a little bit better understanding of the basis for us feeling that they have actually met this criteria.

That's all I have.

VICE CHAIRMAN BONACA: Thank you very much.

Now I would like to just mention that I thought it was a very good presentation on your part. I think it was one of the better presentations we had insofar as being informative. And I'm saying this just because, first of all, to recognize you but also to say that this kind of format for the final presentation to the ACRS I think is valuable. It, you know, comes down to issues that we have expressed concern on rather than just simply statements of closure of open items.

So with that, I thank you. And I would like to know if there are any comments from members of the public, or questions. There are none. Therefore, I'll give it back to you, Mr. Chairman.

CHAIRMAN APOSTOLAKIS: Thank you, Dr. Bonaca. We'll recess until 10:25.

(Whereupon, the proceedings in the foregoing matter went off the record at 10:04 a.m. and went back on the record at 10:23 a.m.)

CHAIRMAN APOSTOLAKIS: Okay. We're back in session.

The next item is the Dresden and Quad Cities core power uprate. Dr. Ford has an announcement to make.

MEMBER FORD: Being a GE retiree, I have a conflict of interest.

CHAIRMAN APOSTOLAKIS: Okay. And the Chairman of the cognizant subcommittee is Professor Wallis, who will lead us through this discussion. Graham?

MEMBER WALLIS: Thank you, Mr. Chairman.

I'd like to point out to the Committee that these applications for a power uprate from Quad Cities and Dresden resemble the application from Duane Arnold that we reviewed last month. The major technical issues are much the same as in their previous application.

The Thermal Hydraulics Subcommittee met with Exelon and the staff on October 25th, 26th, for a total of one whole day. And Exelon and the staff now have to compress those earlier presentations by a factor of four, so I propose to dispense with any further introduction and invite John Nosko to begin his presentation on behalf of Exelon.

MR. NOSKO: Thank you, Dr. Wallis, and Mr. Chairman.

On behalf of Exelon Nuclear, we would like to thank you, thank the Committee, for reviewing our application and our submittal, and for giving us the opportunity this morning to make this presentation.

Our presentation does follow the published agenda. It incorporates materials to address the questions received from the ACRS before the meeting. There is one question that did come to us late yesterday on core parameters. It is not part of our main presentation, but we will be prepared to discuss it during our section on response to subcommittee questions.

Our submittal is requesting a 17 percent increase in license power level for the Dresden station and a 17.8 percent increase for Quad Cities station. The goals of our project are to safely use the excess capacity currently available at the stations to increase power production levels to leverage industry experience by using a proven and accepted methodology to minimize the impact of the uprate on the stations by maintaining a constant reactor dome pressure, and to make our analyses and designs for both stations as similar as possible, to simply reviews and configuration management.

We'll be taking advantage of installed

spare capacity at the stations. The clearest example is that we'll be operating all four of our condensate and condensate booster pumps, and all three of our motor-driven reactor feed pumps. I should note that using all installed feed and condensate pumps is not uncommon in the industry.

This uprate will be accomplished in one phase. The plant modifications will be installed during the next refueling outage for each unit and in the online period immediately preceding that refueling outage. And following the uprates, our units will be generator limited, which means we'll be varying reactor power seasonally to maintain maximum output from the generators.

This next slide summarizes the differences in key operating conditions between the plants today and what we expect after the uprate. At Dresden, thermal power is increasing from 2527 megawatts thermal to 2957 megawatts thermal. Quad Cities is currently rated at 2511 megawatts thermal, but is increasing to the same uprated power level.

Steam flow is increasing from 9.8 million pounds per hour to just over 11.7 million pounds per hour. You can see maximum flow through the core does not change, and neither does reactor dome pressure and

temperature.

Looking at some significant plant differences, the Dresden and Quad Cities are BWR-3 sister units, but there are differences between the plants. There's a slight difference in license thermal power levels, as I just mentioned. Quad Cities has a mix of Siemens and GE fuel in the core, but Dresden-3 no longer has any GE fuel in it. Dresden-2 recently reloaded new GE 14 fuel during this past refueling outage that just completed.

At our meeting with the subcommittee a couple of weeks ago some differences in the power-to-flow maps for the two stations were noted. Although the MELLLA line for both maps is the same, there are differences in the natural circulation lines and the recirc pump minimum speed lines.

Stations originally had the same natural circulation line, but some years ago Quad Cities station was able to collect plant data that revised their PIRT. And, in addition, Quad Cities has a limit of 32 percent for their recirc pump minimum speed to avoid system vibrations, but Dresden is able to operate satisfactorily down to 28 percent speed.

Dresden and Quad Cities have different systems to provide key functions at the plants. For

core isolation cooling, Dresden uses a nearly passive isolation condenser system. Quad Cities has a single multi-function RHR system, but Dresden has separate systems for shutdown cooling and for low pressure coolant injection. And a physical construction difference at Quad Cities allows cross-tying of their spent fuel pools.

Looking at some of the plant modifications now, new GE 14 fuel assemblies will replace the existing GE and Siemens fuel. This will be done gradually over three or four operating cycles, and this new fuel will allow us to reach the higher EPU power levels while maintaining a 24-month operating cycle.

I mentioned Dresden and Quad Cities are BWR-3 units. As such, their steam dryers are smaller than the later designed BWR-4s, 5s, and 6s, and are not able to handle the increased steam flow and extended uprate as well. So to prevent the higher moisture carryover levels that would have otherwise been predicted, we decided to modify the steam dryers to keep those levels to no greater than they are today.

We're adding clamps to eight of the 20 jet pump sensing lines to eliminate a concern for

potential vibration-induced failure of those lines caused by the passing frequency of the reactor recirc pumps.

A research system runback and a low water level SCRAM setpoint change are being added to improve station availability. Today only two of the three reactor feed pumps and three of the four condensate pumps need to operate at rated power, and if a pump trips, the standby pump automatically starts.

After the uprate, we will no longer have a standby pump, so we're adding this runback feature, the SCRAM setpoint change, to prevent a low water level SCRAM on loss of either a single feed pump or a condensate pump.

Changes to the isolation condenser time delay relay and to the low pressure coolant injection swing bus timer are being made to reflect accident analyses for the extended uprate, and we're also making setpoint changes to nuclear instrumentation.

MEMBER WALLIS: In your presentation, will you go back into the -- go back over some of the new accident scenarios that are envisaged with the runback?

MR. NOSKO: We will be able to discuss that at that point in time, sure.

MEMBER ROSEN: Will you also be able to discuss the testing that you envisaged for the runback system?

MR. NOSKO: Yes, sir. Yes, sir, we can discuss that. We do have a separate section on testing and implementation later on, and we'll be glad to incorporate that.

For our balance of plant -- I'm sorry, sir.

MEMBER LEITCH: Excuse me, John. Will the plant be able to reach the full extended license capability after the first cycle of -- after the modification is done in the first refueling outage? Or will that require three refueling outages until you get all of the new GE fuel and --

MR. NOSKO: No, sir. We will be able to reach full power. I did mention that we will be generator limited, so for that reason we might be a couple of percent megawatts thermal shy of what the license request is.

MEMBER LEITCH: So it could be that -- I think at Byron and Bradewood that that is the situation, isn't it? In other words, you're running at like only 99 percent power because of -- in other words, you're not able to achieve the license --

MR. NOSKO: Byron and Bradewood, there is a -- it's Byron station and -- one of the units at Byron station, and that's not to do with the fuel. It has to do with the way they're measuring feed flow.

MEMBER LEITCH: I see.

MR. NOSKO: So, for us, we will be able to achieve -- with the first refueling, we will be able to achieve the higher power levels.

MEMBER LEITCH: Okay. Thank you.

MR. NOSKO: Yes, sir.

Continuing, then, with the balance of plant modifications. We're making changes to the high pressure steam path. We're installing a new high pressure turbine, and we're changing the setpoints of the cross-round relief valves.

The piping analyses that were conducted show that we needed to make changes to our main steam and TORUS attached piping supports as well as to some dry well support steel. We're upgrading the interrupting capability of the non-safety-related 4KV switch gear to handle the additional running loads.

A feature to trip the delta condensate pump on -- if -- in the event of a loss of coolant accident is being added, so we can retain the ability to shut down with feedwater. And there are more

changes, but time doesn't permit me reviewing all of the balance of plant changes to other systems.

We performed all of the evaluations required by the licensing topical reports for extended power uprates. Those analyses used NRC approved methods within previously accepted ranges. And in all cases the results were within the acceptance criteria for the ultimate EPU configuration of the stations.

And with that, I would like to introduce Tim Hanley of the Quad Cities station, and Jason Post of General Electric Company, who will begin the discussion of analyses and evaluations with the thermal hydraulic analyses conducted for the uprates.

MR. HANLEY: Hi. My name is Tim Hanley. I'm the Senior Reactor Operator at Quad Cities station and the senior license holder at Quad Cities station. I'm going to cover stability, and then Jason will take over and cover the ATWS analysis.

Why don't you go ahead and go to the next slide, and I'll talk through that.

Both Dresden and Quad Cities currently are operating under the interim corrective actions for stability, which basically has two facets. One is we avoid intentionally entering the regions of instability, which are shown in the upper left-hand

corner of the graph up there.

The key operational aspect of that is there has to be adequate room between the cavitation pump line and the instability region to allow the operators to maneuver the plant to get through there to get up to full power. On the graph you'll see the line on there. That is the last Quad Cities unit to start up. And as you can see, there is adequate margin in between the minimum pump speed cavitation line and the instability region. And that doesn't change for EPU.

MEMBER WALLIS: Which of the 10,000 lines on this is --

MR. HANLEY: Okay. These are the regions of instability. These two regions here are regions where if you enter them, you monitor for instabilities and take immediate actions to exit those regions. This up here is the immediate SCRAM region. If the -- you get into this region, the operators immediately SCRAM the reactor.

The line I was talking about, the redline here, that is the last Quad Cities unit to start up. The region that for -- operationally, you have to have adequate room in here for the operators to maneuver the plant, so you can get through this region without

getting into the instability region. You have to be able to increase recirc pump speed to increase power without going into the instability region.

The margin between the pump cavitation interlock line, which is what says you can raise recirc pump speed, and the bottom of the instability region doesn't change for EPU. In fact, it stays exactly the same. We have maintained the absolute power levels and flow levels that you'd find in the bottom of the potential instability region when we go to EPU.

The only real changes here is because we are implementing MELLLA as part of EPU to allow us to get up to our new rate of thermal power, we've extended both the immediate SCRAM region and the region here where we can monitor for instabilities and take action to exit the region to account for that area where we will not be able to operate by going to MELLLA.

The other aspect which we've covered of stabilities a little bit already is that what the operators do if they get into the instability region. In these two regions, they would monitor for instabilities by watching their nuclear instrumentation, look for increased amplitude in the

oscillations. If they see that, they'll SCRAM the reactor.

Otherwise, we insert rods to reduce the flow control line down to a point where we're outside the instability region. It's all covered in operator training. It's aided by computer alarms that warn the operators of they're in the regions. So, really, for EPU, the only changes for both stations is that we'll be extending these lines or these regions to account for the MELLLA regions.

MEMBER ROSEN: What do you do in simulator training to address those kinds of -- getting into those regions?

MR. HANLEY: Yes. The most likely cause of getting into these regions is a loss of a recirc pump. You know, if you're operating it along this high flow control line, and you lose a recirc pump, you're going to run back along that constant flow line -- or constant power line.

The operators have to know which is part of their turnover and what flow control line they're operating at. If they get a trip of a recirc pump, the computer will alarm, say you're in the instability region. If you're above what was our current 100 percent flow control line and flow gets below this

level, they'll immediately SCRAM the reactor. Otherwise, they insert control rods to get out.

We do have certain scenarios that they have to detect the instabilities. We actually give the nuclear instrumentations giving the oscillations, so they have to detect that and SCRAM the reactor instead of just inserting rods to get out of there. That's considered a critical step in those test scenarios that they actually can -- do see that and take the appropriate action.

MEMBER WALLIS: Is this picture for Dresden or Quad Cities?

MR. HANLEY: Well, that's what's a little bit confusing. The power flow map is Dresden's, the startup is Quad's, which is why that line is not right on top of this minimum pump speed line.

MEMBER WALLIS: So how about natural circulation, which one is that?

MR. HANLEY: It's also the Dresden line.

MEMBER WALLIS: And could you sketch where the Quad's natural circulation line is?

MR. HANLEY: The Quad natural circulation line is a little bit different shape.

MEMBER WALLIS: It's quite a lot different, isn't it?

MR. HANLEY: But I believe it starts slightly higher.

MEMBER WALLIS: And it bows out --

MR. HANLEY: And bows out further. That's correct. That --

MEMBER WALLIS: This is just because it's based on plant data instead of theory, is that --

MR. HANLEY: Yes. At Quad Cities in I believe either the mid-to-late '70s they had a trip of both recirc pumps. At that time, we weren't required to SCRAM the reactor on a loss of forced recirc flow. We were allowed to shut down. What they did is they plotted the points for the natural circ line as they shut down.

Dresden is still using the generic GE natural circ lines for their plants, because they've never had an opportunity --

MEMBER WALLIS: Which appears to be not that accurate a prediction, right?

MR. HANLEY: Well, I think it's fairly generic, and it wasn't aimed at predicting the exact plant. The important point is neither plant is allowed to operate with natural circulation any more, so the exact shape of that line doesn't mean a lot to the operation of the line. They're not allowed to

operate in that region anyway.

MEMBER WALLIS: It is a kind of cutoff, though, so it -- it's useful for the operators to know where it is.

MR. HANLEY: For the natural circ, like I said, we don't even go below the minimum pump speed line. That's what's really important for the operators to know. The recirc pump is operating along the minimum pump speed line, and that's really more useful for the operators than what the natural circulation line is.

So, really, for overall stability for neither -- the plants don't change, the way we're addressing them. Both plants have installed OPRMs for the long-term solution for this. However, there is a Part 21 notification out on that, and we are not going to have that put into the RPS trip system until that Part 21 notification is resolved. That was true EPU or non-EPU. So until that Part 21 notification on the OPRM gets resolved, we will be operating both units under the ICAs.

With that, I'd like to turn it over to Jason Post of General Electric to discuss the ATWS analysis.

MR. POST: Yes. I'm Jason Post. I'm the

Manager of Safety Evaluations and Engineering Quality at GE Nuclear Energy. On the ATWS analysis for the EPU we do a full scope ATWS analysis to ensure that the ATWS mitigation systems are acceptable, meet the requirements, and also to show that the change from an EPU is not that large. The change is acceptable.

We maintain integrity in three areas. One is the reactor, second is the primary containment, and third is the fuel. Reactor integrity is demonstrated by the peak vessel pressure. We use the ASME service level C limit of 1500 psig. The pre-EPU result there is shown as 1402 psig. The EPU result did increase the pressure. The peak result for GE 14 was 1492, and with the transition core it was 1499.

So it is -- there are conservative factors in the analysis, and we do meet the peak vessel service level C.

MEMBER WALLIS: This is right up to the limit, though. 1499 is essentially at the limit of 1500.

MR. POST: It is right at the limit. That's correct.

MEMBER WALLIS: And earlier Mr. Nosko said that you were -- said there's balance of plant limit, there's some turbine limit in power I think. It looks

as if this is also a limiting condition, since you are coming up to the limit of peak vessel pressure.

MR. POST: That's correct.

MEMBER WALLIS: So you are limited by safety considerations.

MR. POST: That's true.

MR. HAEGER: Well, I should add -- this is Al Haeger. I should add we chose the -- initially chose the license power level based on the generator limit, and then this is a result of --

MEMBER WALLIS: This also turned out to be a limit, and it might have -- might have turned out to be a little closer, and then you'd have to go back and say it's not the generator that limits, but it's ATWS that limits.

MR. POST: There are things that can be done I think to mitigate this response if it was necessary -- instrumentation setpoints, recirculation pump trip setpoints. Those sorts of things could be done to improve this response if it was necessary.

For the primary containment, there is two factors we look at -- the peak suppression pool temperature and the peak containment pressure. Peak suppression pool temperature -- we use 202 degrees, which happens to be the peak result from the loss of

coolant accident calculation on the containment response.

We could probably justify a higher temperature as a limit, but it simplifies it just to say what they justify for LOCA is the same temperature we're going to use here. The pre-EPU result was 190 degrees Fahrenheit, so it did increase by 11 degrees for the EPU up to 201.

Peak containment pressure, 62, we're nowhere near that limit. This is not a LOCA event, so there's no blowdown to the dry well. It's just steaming to the suppression pool. It's a thermal hydraulic calculation, a thermodynamic calculation to calculate the pressure. It's well below the limit.

Peak fuel temperature -- we use the 10 CFR 50.46 limits, 2200 degrees, and 17 percent local oxidation limit. The result -- this is a case where the peak temperature result is due to boiling transition, so there's no uncovering of the core. The core is never really threatened.

But we do a very conservative calculation of the boiling transition, and that results in a temperature here of a little bit less than 1500 degrees. With that, there is -- the metal/water reaction is negligible.

MEMBER LEITCH: Do these plants have two manually operated slick pumps? Is that the --

MR. HAEGER: That's correct.

MEMBER LEITCH: And there is no provision here for automatic slick injection on a --

MR. HAEGER: That's correct.

MEMBER LEITCH: There is none.

MR. HAEGER: There is no automatic slick injection.

VICE CHAIRMAN BONACA: So could you comment on -- I mean, there are embedded operator actions and time for interaction in these calculations, right, these results?

MR. POST: That's correct.

VICE CHAIRMAN BONACA: Could you comment on those? I mean, I would like to know --

MR. POST: Yes. We use a two-minute operator action time for the SLCS injection after the ATWS signal has occurred or the suppression pool temperature has reached the peak -- the Boron initiate -- Boron injection initiation temperature, whichever is later.

So it's some time, two and a half minutes, something like that, into the event that we're assuming the operator has initiated Boron. Then there

is some time delay before it actually reaches the core.

VICE CHAIRMAN BONACA: And what's the difference between the previous power level and now, insofar as the time?

MR. POST: It's almost insignificant. The initial peak pressure transient is really governed by the MSIV closure, and there's really very little difference in the time. We use exactly the same time for both analyses. So we've not shortened the operator action time to mitigate the higher power level. We use the same operator action time.

MR. HAEGER: Now, you're going to see later that for the probabilistic risk assessment one of the success -- you know, success criteria are also based on operator action time, and that didn't change also for the short -- for what we call the early standby liquid control initiation success criteria for power uprate. It didn't change there either.

It did change for the other -- what we call the late success criteria. It changed slightly in the PRA space. But for the deterministic analysis, the time didn't change at all.

VICE CHAIRMAN BONACA: So you had the same assumption of the timing for operator action.

MR. HAEGER: That's right.

MEMBER LEITCH: So some plants have a system that if power is still up six seconds after SCRAM they automatically inject slick. And what you're saying is had you such a system, it wouldn't appreciably reduce that peak vessel pressure?

MR. POST: No, that's correct. It would not. The Boron system has very little impact on the peak suppression pool -- peak reactor pressure because that occurs before the Boron has any impact on the event.

MEMBER LEITCH: The main issue is the speed with which the MSIVs close. Is that --

MR. POST: It's the recirculation pump runback and how fast that pump runback gets the power down is the main driver to reduce that peak pressure, and the SRB capacity. A lot of -- some plants have more SRB capacity than the Dresden and Quad Cities units, and they're going to have a better response, a lower pressure in the response.

MEMBER LEITCH: Okay.

MR. POST: So moving to ATWS instability, this is something that's generically dispositioned. There was not a specific analysis for Dresden and Quad Cities. The event is of -- like a two recirculation

pump trip from a limiting EPU condition on a MELLLA boundary. You run back to natural circulation, manual SCRAM fails, and an instability develops and grows, and the operator is completely unable to insert any control rods.

There were two reports that were written several years ago that have been accepted by the NRC. The first one is NEDO 32047, and that one shows the response to this event with no mitigation at all. And it shows that the highest power bundles do go in and out of boiling transition due to the reactor oscillations, and eventually they -- a few of the highest power rods experience an extended dryout, and with that they heat up enough to cause core damage.

And as reported in that report, they are -- about half a percent of the core by volume will experience this extended dryout and boiling and some fuel damage.

The companion report was 32614, and that shows the ATWS response with mitigation, and it determined two key factors to prevent fuel damage. One was to lower reactor water level. When you lower water level you are now putting your feedwater into the airspace in the downcomer, which raises the feedwater temperature dramatically and you get a big

increase in the temperature as it -- at the bottom of the core, which mitigates the instability.

It doesn't make it go away, but these very high power oscillations that can cause the extended dryout no longer occur.

The second is the Boron injection. Again, that does not prevent the instability either, but it does -- it does, over a matter of 10 or 15 minutes or so, make the instability go away completely.

We get -- when we presented this to the Duane Arnold subcommittee review, there was a concern that we hadn't done limiting EPU conditions. And since that time we've gone back and have done a sensitivity study for more limiting EPU conditions, even more limiting than either -- any of the EPU plants that have been presented to this Committee -- and found that the results are essentially unchanged.

We did it for a GE 14, and it has the same or longer time before it experiences the extended dryout, and the mitigation actions are still just as effective.

MEMBER POWERS: When you did the power oscillations, what kinds of energy deposition do you have in the fuel?

MR. POST: There are around 70 to 80

calories per gram is the energy deposition rate.

MEMBER POWERS: And how do you know the fuel survives that?

MR. POST: Well, it's well within the limits of what the design -- what the fuel is designed for. I think it's -- the licensing limit is like 170 calories per gram, and we think it will take well more than that.

MEMBER POWERS: I wonder why. I mean, we have a history of experiments now showing that as we burn fuel up it takes less and less, and the original idea that this fuel would stand up to 180 calories per gram has pretty much evaporated as you go to burnups about 20 gigawatt days per ton.

Now you're telling me we're putting in 70 or 80, and I seem to be -- to recall experiments where those kinds of powers caused fuel damage in experiments, admittedly not this fuel but other types of fuel.

MR. POST: Yes. I'm going to have to say I'm really not the expert in that area. Dr. Yans Anderson was here previously and answered a very similar question, and, unfortunately, he couldn't be here today. But I would want to get back to you with an answer from someone like Dr. Anderson from Global

Nuclear Fuel.

MEMBER POWERS: Okay.

MEMBER LEITCH: My question -- I'm sorry. Were you finished? Okay. My question related to the likelihood of an ATWS. Do these plants all have an alternate injection?

MR. POST: Yes, they do. Yes, we don't take credit for that in any of our analysis, but they have it.

MEMBER LEITCH: Thank you.

MEMBER ROSEN: Do you actually simulate ATWS and simulate operator responses to these instabilities during ATWS?

MR. POST: In the analysis or --

MEMBER ROSEN: No, in the simulator.

MR. POST: -- in the simulator?

MEMBER ROSEN: And in the training.

MR. HAEGER: I'd like to get Tim Hanley to answer that question.

MR. HANLEY: This is Tim Hanley again. We do actually do training on this. The generic EPGs, which our site EOPs are based on, does have them looking for instabilities, injecting standby liquid if they hit the Boron injection temperature, or actually before they hit the Boron injection temperature on the

TORUS, or if they see instabilities when they're in an ATWS.

MEMBER ROSEN: Well, I was more interested in the water level reduction.

MR. HANLEY: And, actually, that's the first step. When you go down the level leg in the EOPs, if you're not below the feedwater spargers, it'll tell you to immediately terminate and prevent injection, except for Boron, CRD, and RCIC, to lower level less than the feedwater spargers to prevent its instability.

MEMBER ROSEN: It seems a little counterintuitive for operators to --

MR. POST: Well --

MEMBER ROSEN: -- injection to the core into a unit --

MR. POST: -- when it was first introduced, it was certainly counterintuitive. But it's been the procedure in place for well over 10 years now, since it was first introduced by the Emergency Procedure Committee. And I think the industry well understands the need for it and how effective it is.

MR. HANLEY: This is Tim Hanley again. If the -- you know, if the rods don't go in, all the

operators -- you know, the only way to effectively lower power is, in fact, to lower the moderation by lowering the water level. So although it's counterintuitive to our normal response to most other accidents, this is a particular one that we do do extensive training on.

MR. POST: Next we're going to move into the containment analysis with Mark Kluge.

MR. KLUGE: I'm Mark Kluge. I'm with the Project Engineering Team for the Dresden and Quad uprates, and I'm going to discuss the containment analysis.

First, we'll look at the results for the design basis loss of coolant accident. The peak drywell pressure we reached for EPU conditions is 43.9 psi, which is well within the acceptance limit of 62. And when we performed the analysis with the same assumptions for the pre-EPU case, we found that we changed the peak pressure by only about a pound.

Peak drywell air temperature, as you can see, goes up for EPU only approximately two degrees, and, again, is well within the acceptance limit of 340.

MEMBER WALLIS: This is for design basis LOCA. Which is the worst LOCA? This is the worst you

are looking at here or the --

MR. KLUGE: Loss of coolant accident is the worst case for peak drywell pressure. A small -- a steamline break actually gives you higher airspace temperatures. But, again, the results are well within the limit.

MEMBER ROSEN: How high?

MR. KLUGE: I believe it's 337.9 degrees for that case. That's the bottom case for that particular parameter.

MEMBER WALLIS: So that gets us much closer to the limit, then.

MR. KLUGE: Yes.

MEMBER ROSEN: Now, did you also mean to imply that for that case, for the high temperature case, the small break, that the pre-EPU and post-EPU and EPU numbers are very close?

MR. KLUGE: They are, again, very close. The matter is just a few degrees.

MEMBER WALLIS: But you are also just a few degrees from the limit, so --

MR. KLUGE: Correct. But that's a typical result for these types of plants.

On the next slide we have the results for the suppression pool. Again, doing the analysis with

the same methodology for the pre-EPU and post-EPU case, when we use bounding assumptions that envelope both plants, the post-EPU result for a suppression pool temperature is 202 degrees with a nine-degree rise. And this is the number we used in our piping and structural analysis.

For NPSH, which I'll discuss in a moment, we did plant-specific peak temperatures. And as you can see, there are some minor differences there. The peak wetwell pressure goes up only nominally for the EPU case, and, again, is well within the limit.

MEMBER POWERS: When you do the blowdown into the suppression pool, do you look at chugging?

MR. KLUGE: Yes.

MEMBER POWERS: And what did you find?

MR. KLUGE: Yes, we looked at all of the MARK-1 hydrodynamic loads, and we reran all of the limiting cases and found that the existing load definitions are still bounding for EPU.

We'll move on to NPSH. Both Dresden and Quad Cities require credit and containment overpressure for limiting case NPSH. That is a short-term case where all the pumps are running, and a long-term case where fewer pumps are running, but they are sufficient to maintain both core and containment

cooling.

These next two drafts show that in all cases the available overpressure for an analysis that uses conservative assumptions to limit the pressure exceeds the required credit to maintain adequate NPSH. And, again, there are minor differences due to plant differences.

And if there are no questions in that area, I'll turn it back to Jason to discuss the LOCA analysis.

MR. POST: A full scope LOCA analysis was performed using the standard approved methodology. That analysis starts off with a nominal PCT calculation. It's a nominal assumption to -- it does the full break spectrum and all of the various failures, determines the worst event, worst break. And then, with that, the first thing you do is you include uncertainties and you calculate the -- what's called the upper bound PCT, and that is the one that's shown there just right at the upper bound 1600 degree F limit.

That limit is based upon the limits of the data when that methodology was qualified. There is actually a submittal before the NRC now to raise that limit to 1800 degrees or possibly remove that limit

completely.

Then, in addition, you also take the nominal PCT and you change assumptions for the Appendix K methodology -- these are things like the break flow, the metal/water reaction coefficient, the K-heat conservative adder of 20 percent.

And you redo the calculation for the limiting break and that comes up with the Appendix K result, and then you finally add some additional uncertainties and you come up with the licensing basis PCT, and you must show that the licensing basis PCT is below the 10 CFR 50.46 limit of 2200 degrees Fahrenheit.

MEMBER WALLIS: What was the 1600 degree value before the extended power uprate? What did it come to?

MR. POST: I cover that on the next slide.

MEMBER WALLIS: Oh, you do.

MR. POST: The pre-EPU upper bound PCT was estimated to be 1500 degrees, but that was not for a GE 14 core. And GE 14 is worse than the existing legacy fuel. The legacy fuel -- I'm sorry, for GE 14, the difference of the EPU is only about 10 degrees, so there's a very small difference for -- for EPU. So that the primary difference is due to the different

fuel type.

And analysis results for the licensing basis PCT, it was 2110, which is less than the acceptance criteria. The upper bound PCT was 1599.6, which rounds up to 1600 degrees, so it does meet --

MEMBER WALLIS: Pretty good --

MR. POST: Yes. And the maximum local oxidation was six percent, and the core-wide was .1 percent, so those are well less than the limits.

Next slide.

There was a question from the subcommittee regarding the impact of steam updraft and the fact that you have a flatter radial power distribution and how that impacts this.

A couple of points here. The DBA LOCA analysis for the current power and for EPU results have a high steam updraft in the central core region which prevents the core spray flow from reaching the hot channels. That's part of the analysis. That's the way it's done.

So we do take credit for cooling from the steam updraft, but we do not take credit for any direct spray cooling to the hot channels in the calculation of the LOCA PCT.

Now, the flatter core power profile may

result in a higher power in the peripheral bundles, and so you're going to have more steaming, more steam updraft in those bundles, which can hold up more water in the upper plenum. So you're going to reduce the cooling flow to those, although the increased updraft does help the cooling of those bundles as well.

But it's self-limiting because you're going to reach the volume of -- or the mass of water that's being held up sooner, which will cause breakdown and cause the water to get back down into the core. So it's a self-limiting effect. It really has essentially no impact on the calculation.

MEMBER KRESS: Does this increase the carryover of liquid out the break?

MR. POST: I don't believe so. I'm quite sure it doesn't.

MEMBER WALLIS: Well, if there's a higher steam velocity, you probably will.

MEMBER KRESS: You'll have more steam flowing in a different location and at higher velocity.

MR. POST: Of course, the pressure response is driven by the fact that you have a higher power in the -- you know, in the reactor. It takes a little bit -- the blowdown is a little bit longer.

I'm really not certain that the steam updraft has a significant impact on that blowdown phenomena. I don't think it does.

MEMBER WALLIS: When you get this kind of flow, do you actually make a pool instead of a spray impacting directly on the -- whatever it is, the --

MR. POST: That's correct. There's a pool of water that's held up in the upper plenum.

MEMBER WALLIS: Once you've made a pool, it doesn't really matter --

MR. POST: Right.

MEMBER WALLIS: -- what the distribution of the spray is.

MR. POST: That's right.

MEMBER WALLIS: As long as it's not being blow out the break.

MR. POST: Right.

MEMBER KRESS: Does your computer count -- account for the water that gets blown out the break?

MR. POST: Certainly. It accounts for the water that goes out the stand pipes and spills over into the downcomer. Once it gets into the downcomer, it would flow out the break and would not -- it would be below the jet pumps and would -- it would go out of the break. Certainly, it accounts for that. So if

that effect is there, it would certainly model it.

MEMBER KRESS: And how do you -- what do you input for that in the code? Does it actually calculate it mechanistically, or does it input a fraction of the core spray that goes out?

MR. POST: Frankly, I'm not quite certain of exactly how the model works in that regard, what the coefficients are and how it's calculated. I can't answer that.

There was also, then, the long-term spray cooling. Of course, in the long term you're going to get the void collapse in the core. Water level is going to steady out at the two-thirds core height at the top of the jet pumps. And with the flatter power distribution, that does not impact the spray distribution. It's within the range of the 30-degree sector tests that were performed previously on core spray distribution, so it does not impact that long-term core cooling.

So, next, Ed Connell is going to cover the materials issues.

MR. CONNELL: Good morning. I'm Ed Connell. I'm the Project Engineer for the EPU project at Dresden and Quad Cities.

The first topic I'm going to talk about is

flow accelerated corrosion. For the EPU conditions, we looked at the susceptible piping systems, determined those where the flow or the temperature had increased, and for those we went through and calculated a -- the wear rate, an increased wear rate.

The wear rate increases were modest. The largest was 33 percent, went from 1 mil to 1.3 mil. More typical of a large increase was in the feedwater lines where we went from 19 mils per year to 21 mils per year.

Since the existing wear rates are modest, these increases are routinely accommodated. And the way we accommodate them is we adjusted, as appropriate, the inspection intervals for the program, so the program has been modified to account for these.

MEMBER ROSEN: Could you hold on for a minute? On that slide, you talked about this 33 percent increase, where was that?

MR. CONNELL: That's on the reactor water cleanup line.

MEMBER ROSEN: At what point?

MR. CONNELL: I'm not sure I remember the exact point.

MEMBER WALLIS: This wear rate increase, 1 mil per year to 1.3 mil per year, that's based on

some mechanistic analysis. It's a Reynolds number to the .8 or something like that? What is it based on?

MR. HAEGER: That's really right out of the checkworks program that we discussed last time.

MEMBER WALLIS: Which is too complicated to describe here.

MR. HAEGER: Well, at least none of us sitting at the table can describe it very completely. What we showed last time, though, was that the parameters we're using are within the bounds of checkworks that other plants have typically used.

MEMBER LEITCH: Did I understand you to say that the critical point here was reactor water cleanup?

MR. CONNELL: It's not a critical point. It's a point that exhibited the largest percentage increase.

MEMBER LEITCH: My question really was: why does the reactor water cleanup flow change?

MR. CONNELL: It's -- you get slightly more subcooling. You get a little more flow down that as you come off the vessel. So you've got a slight temperature increase.

MEMBER FORD: I think your point is that this is Schedule 80 pipe, about .3 wall thickness, .3

of an inch, about .375 wall thickness, and your inspection period is -- hat you'll take that increment well into account, is that correct?

MR. CONNELL: That's correct.

MR. HAEGER: Yes. Just to clarify why we showed that number, we wanted to show you the largest percentage increase and then the largest absolute increase, just so you get some feel of where these increases were.

MEMBER WALLIS: It would be good to put it in perspective of how much you need to wear away the -- to have a problem.

MEMBER ROSEN: This is gun barrel piping, Schedule 80.

MR. HAEGER: Is that right?

MR. CONNELL: I believe that's correct. We can look.

MEMBER WALLIS: 375 wall.

MEMBER POWERS: How often do you have to change your feedwater line?

MR. CONNELL: How often do we have to change it because of this? It won't change it at all.

MEMBER POWERS: A hundred years maybe?

MR. CONNELL: Perhaps that. But we won't change it within the licensing on it.

MEMBER POWERS: Nothing for the wall?

MR. CONNELL: Yes. I'm trying to remember. There's something -- they're over an inch, but I -- I don't remember.

MEMBER FORD: The feedwater lines are pretty big things, so Schedule 80 is -- it's a vague statement. It's a thick pipe.

MEMBER WALLIS: It would be nice just to have some numbers that make it clear.

MEMBER SHACK: This is, what, a 24-inch pipe, Schedule 80? About an inch and a quarter, inch and a half, yes.

MR. CONNELL: Yes, that's approximately correct.

MEMBER SHACK: It's at least an inch.

MR. CONNELL: Yes, it's over an inch.

MEMBER SHACK: It's over an inch.

MEMBER POWERS: Well, it's a good thing, because in four years you're going to remove a lot of it.

The next slide is on the reactor vessel fluence. As part of EPU, the fluence to the end of life has been recalculated. It's been recalculated using the revised General Electric methodology. At the time we did that work, the methodology had not

been approved by the NRC staff.

It's now been provisionally approved. What we looked at in the interim was the PT curves for the -- the existing PT curves, and they are sufficiently conservative. There's enough life left that we will have time until past the end of the next cycle to go back and incorporate the methodology in the General Electric new topical report that's just been approved.

MEMBER POWERS: So you don't discuss fatigue?

MR. CONNELL: No, we -- we hadn't planned on it. The existing curves will go right over it. It'll carry us --

MEMBER POWERS: There's no --

MR. CONNELL: -- through that.

MEMBER POWERS: -- on your vibrations and --

MR. HAEGER: Oh. We discussed that in some depth at the subcommittee. We were not asked to specifically present it here. There is one open question that we're going to be responding to, but other than that we didn't plan to address it specifically here.

MEMBER POWERS: I'll chat with my brethren

on the subcommittee.

MR. HAEGER: Okay.

MEMBER POWERS: They can answer my question.

MR. CONNELL: Next, Jason and I are going to address four open questions from the subcommittee. The first two have to do with the electrical distribution system, and they are for postulated off-normal conditions.

The first concerns the -- what we call the bus 21/22, which are off the Y windings, off the unit auxiliary transformer, and the reserve auxiliary transformer. And they feed the recirc pumps and the feedwater pumps.

The postulation is that there is a bolted fault at the same time that you transfer all the loads from one of the transformers to the other. This is different after EPU basically because you're running the additional feed pump. So the contribution to the fault current will be increased momentarily because of the additional running feed pump.

So when you look at that, the fault current is higher after EPU. So what we have done to mitigate that is that we have reinforced the bus to take that higher momentary current, and we've done

that through the aid of testing to prove out that the modifications will, indeed, take that higher fault current.

We have also adjusted the relay that initiates the breaker trip, has two settings on them. One we call instantaneous, which picks up in about a hundredth of a second. We've eliminated that, and now we pick up on the setting that's set at six cycles. It'll pick up at six cycles or a tenth of a second.

And during that time period, the fault current will decay from the extra pump, and you'll be back within the rating of the breaker. We've also looked at all of the other components, I think in response to a question. That question was: in the transformer, is that designed to take this? And it is. And we've also looked at the connecting buses, and that's within their rating also.

The second question related to electrical had to do with the -- on this postulation, the plants are running, you've got the low split between the UAT and the RAT, and you have a fast bus transfer from one to the other. The question was related to the higher current. The current will exceed the continuous duty rating of the transformer. However, the current is within the short -- the short overload period of

design of the transformer.

And, of course, we've also looked at the other components in the system, such as the bushing and the cabling and the bus, and that's all within its short duty rating.

During that time, the operators are trained and they have a procedure where they'll cut back the load to be within the continuous duty rating. And we've allowed them an hour to do that, because the transformer short duty rating for the overcurrent is in excess of two hours.

The last question that I'm going to address had to do with the steam dryer. At the subcommittee, there were extensive discussions about the dryer, and there was one question that was asked that hadn't been answered, which had to do with the lugs on the dryer.

And the question was: are these inspected? And the answer is: they're inspected at 10-year intervals. They were inspected during the EPU outages. We just did that last week at Dresden, and there were no indications in any of the lugs.

MEMBER FORD: I guess the question -- you enunciated a question correctly, but the deeper issue was that in the earlier Duane Arnold application, the

statement was made that because of the increase of vibration stresses on the steam dryer, there would be a transference of stress to the lugs.

My question was: well, how will that impact on the cracking of that welded component, the lug? And you've correctly said that there would be -- they are normally inspected every 10 years. Would the increase of stress on that lug indicate that that is -- 10 years is an insufficient inspection periodicity?

MR. CONNELL: I guess I wasn't prepared to -- I didn't understand that question in that way.

MEMBER FORD: Well, I didn't give, admittedly, it in that detail. It was really to relate to the integrity of that lug, which has cracked in the past. How is that impacted by the increase -- supposed increase in stress?

MEMBER SHACK: Do you mean, how close do you come to a fatigue limit?

MEMBER FORD: Fatigue or a cracking limit, a stress corrosion limit, or whatever.

MR. CONNELL: I understand your question now, but I didn't understand that was the question. Sorry.

MEMBER FORD: I apologize. I apologize.

MR. HAEGER: We can get some information

back to you on that.

MEMBER FORD: Yes. And if you remember, the impact of this was really more of a loose parts analysis. You're going to have the whole steam dryer drop down onto the top guide. And I think it -- what would happen? Or can't anyway.

MR. CONNELL: Jason?

MR. POST: Yes. There was a question on the ORIGEN Code from the subcommittee, and if that's used to do a space-time demand calculation. And ORIGEN is used to calculate the core inventory for the radiological release calculations, the dose calculations. It's a prescripted methodology. It's performed at end of cycle with a maximum discharge exposure to maximize the inventories.

It is not used to do a space-time variation calculation. We have compared ORIGEN to the CINDER Code, which is a model that can do a space-time variation calculation, and have shown that ORIGEN results are either the same or higher for the individual isotopes, and so it gives a conservative radiological release calculation.

Now, there was also a question about the radial power distribution.

MEMBER POWERS: I guess that raises the

question --

MR. POST: Sure.

MEMBER POWERS: -- I am hardly expert in this, but I seem to have seen people compare ORIGEN predictions to what they actually find in the fuel, and my impression is they're pretty good. That would suggest that maybe the CINDER Code is not so good.

MR. POST: Well, the results between CINDER and ORIGEN were really quite close.

There was another question on the radial power distribution. This is Dresden-2, cycle 17, which is the current operating condition. This is a core -- say a core to core. The numbers there are the -- let me use this and stand up.

These are the radial peaking factors of the individual fuel rods. Here are -- these little cruciforms are where the control rods are inserted. This -- again, it's a core to core. It's a core-to-core symmetric design.

There are four bundles on here that have the highest radial peaking factors of 1.4 or so. I think there is -- where did they go here? There was a couple of them --

MEMBER ROSEN: Is this the pre-EPU or post-EPU case?

MR. POST: This is the pre-EPU. This is cycle 17. This is the current operating condition.

MEMBER WALLIS: Can we win a prize for finding them?

MR. POST: Yes. The first one to find them gets a free donut.

(Laughter.)

I know there were four -- there were four of them on here. They were about 1.4, I thought.

MEMBER WALLIS: They all seem to be 1.2 something.

MR. POST: Yes.

MEMBER WALLIS: So what's the question?

MR. POST: Then it -- I'll have to confirm that. Then this is cycle -- Dresden-2, cycle 18.

MEMBER WALLIS: There are some 1.4s on this one.

MR. POST: Yes. This one -- I counted. There's -- here's a whole bunch of 1.4s. This is the EPU condition, and there are approximately 23 -- I think I counted -- fuel rods that have a radial peaking factor of 1.4 or higher. So the peak is --

MEMBER WALLIS: So it has increased.

MR. POST: Yes. So the peak is still the same. There's nothing above a 1.44 or 1.45 or so.

That's the highest. But there -- it went from four in a core to core to 23 in a core to core.

MEMBER WALLIS: So except we couldn't see the 1.45 and --

MR. POST: Yes. I'm not sure that that was the correct transparency. I'll have to confirm. Because I counted them off the hard copy, and I counted four, so --

MEMBER WALLIS: So the message is that the maximum radial peaking factor has not changed.

MR. POST: Correct.

MEMBER ROSEN: But that pre-EPU you had some small number of bundles at 1.4, or nearly, and post-EPU or EPU you end up with something like 24 bundles.

MR. POST: In a core to core, correct.

MEMBER ROSEN: In a core to core. But overall the power is generated for the EPU from a general flattening of the power shift.

MR. POST: Right. And the radial peaking factor of more rods at 1.4 is evidence of that, that it's a flatter power distribution. Exactly.

MEMBER ROSEN: But it isn't very core wide. It doesn't take -- doesn't seem to take -- that was the reason for my question. It doesn't seem to

take much of the core to get there.

MR. POST: It's a matter of perception. Certainly, that -- yes. It's -- there is still a low of low power bundles in here. I mean, out in the periphery we've got 1.3s, 1.2s, that's correct. There are a lot of low power bundles still in the core.

MEMBER WALLIS: Well, for the benefit of the public, could you explain the significance of this term "radial peaking factor"?

MR. POST: The radial peaking factor for the whole core average should be 1.0. So it's a measure of the individual bundle power ratio to the core average bundle power.

MEMBER WALLIS: Core. It's not bundle average.

MR. POST: Core average.

MEMBER WALLIS: So you can have numbers that are less than one.

MR. POST: That's correct.

MEMBER WALLIS: But it doesn't say how high it is, then. It's a ratio to the core average.

MR. POST: That's correct. And --

MEMBER WALLIS: Would it be a correct statement that the power per bundle has not changed in the maximum bundle by -- as a result of the EPU?

MR. POST: That's exactly correct. We --

MEMBER WALLIS: It's not just the ratio to the average, but the absolute power per bundle.

MR. POST: Right. The highest --

MEMBER WALLIS: The highest amount of power per bundle is still the same.

MR. POST: The highest power bundles were on limits, and we were not able to raise the power.

MEMBER WALLIS: That's the whole principle of achieving EPU this way, by spreading --

MR. POST: That's correct.

MEMBER ROSEN: Maybe a comment for the process is that we're talking -- on the assumption that we're going to see additional requests for other BWRs on this for EPU, it would be helpful if this presentation was made with some sort of help for the reader, maybe some kind of color coding. It's very hard to compare.

MR. POST: Yes. We just got this question --

MEMBER ROSEN: Yes, I know.

MR. POST: -- last night. And so this is the best we could come up with in the moment. We'll certainly take that into consideration for future presentations.

MEMBER WALLIS: Are we moving on to PRA? Is that the next -- oh, no, the large transient tests you're going to talk about.

MR. HAEGER: Two open items, actually.

MR. KLUGE: This is Mark Kluge from Exelon again. I'm going to discuss the first of the two open items in the safety evaluation report.

Al, can you put our slide back up, please?

This open item involves the ultimate heat sink at Dresden station. Dresden's ultimate heat sink consists of the intake and discharge canals, which trap water in the event of a failure of a downstream dam on the river. And I'll ask Al to put up a photograph here.

The Unit 2 and 3 intake canal runs from the river to the plant, and the discharge canal runs back out to the river here. The intake is approximately 2,000 feet long. So we're talking about a substantial amount of water.

Al, if you could switch back.

This inventory is used for safe shutdown in two ways. It supplies makeup to the isolation condenser for decay heat removal, and it also supplies cooling water for the diesel generators. The ultimate heat sink is replenished by means of portable pumps to

support safe shutdown in the long term, and all of the required actions for operating in this matter are in the current plant procedures. The PU --

MEMBER WALLIS: Where do you pump from?

MR. KLUGE: I'm sorry?

MEMBER WALLIS: Where do you pump from with the --

MR. KLUGE: We pump from the intake, as we do during normal plant operation. The difference, of course, is that we're now separated from the river as an unlimited supply.

MEMBER WALLIS: The canal is replenished by pumps pumping from the river?

MR. KLUGE: Pumping from the lowered river bed.

MEMBER WALLIS: After the dam has failed?

MR. KLUGE: After the dam has failed, the river bed lowers below the canal intake level, but, of course, doesn't go completely away because the river has a series of dams.

MEMBER WALLIS: So the aftermath of the dam failure has all gone away and the river is now in a suitable state for pumping from?

MR. KLUGE: The river is presumed to still have inventory, yes. And we're only pumping the water

over the rise at the intake.

MEMBER WALLIS: And not to be full of all kinds of junk and stuff, is that -- pumpable from?

MR. KLUGE: Pumpable from.

MEMBER WALLIS: Okay.

MR. KLUGE: Yes.

MEMBER WALLIS: That doesn't always happen, right?

MR. KLUGE: That doesn't always happen, but that is the current licensing basis.

MEMBER WALLIS: So this is approved by the NRC?

MR. KLUGE: The EPU impact on the ultimate heat sink we evaluated by doing a very bounding analysis of the water that would be available in the intake canal and found that EPU changes the time available to make up from the lowered river bed from about five and a half days to four days.

As a result of our IPEEE and seismic margins analysis, we committed to certain modifications which are related to a seismic event. Specifically, we do not currently have a seismically qualified makeup path to the isolation condenser.

And because those modifications are not intended to be installed until one cycle after EPU

operation, the staff requested that we do some focused risk evaluations of such a scenario in which the seismic event would fail the dam, and the makeup paths to the isolation condenser have limited seismic capability.

The results of those evaluations showed that the risk of core damage in that scenario was acceptably low, and that the EPU impact on that risk was negligible.

Now I'll turn it over to Tim Hanley to discuss transient testing.

MEMBER ROSEN: Before you get away from that, acceptably low, what kind of numbers were you talking about?

MR. KLUGE: The risk of a seismic event failing the dam, failing all of the isolation condenser makeup, and thereby leading to core damage, is on the order of $1E^{-5}$.

MEMBER KRESS: And where is it that says that that's an acceptably low value?

MR. KLUGE: That falls within an acceptable region in Reg. Guide 1.174.

MEMBER KRESS: I don't recall 1.174 giving acceptance criteria for individual sequences.

MR. KLUGE: Well, as I said, this was a

special case where the staff asked us to analyze one specific sequence. We do not have a seismic PRA for Dresden station.

MEMBER KRESS: Yes, but I don't think 1.174 gives any guidance on what to do about individual sequences. So, you know, did the staff say that it was an acceptably low value?

MR. HAEGER: Well, as we are discussing, this is still an open item with the staff.

MEMBER KRESS: I see.

MR. HAEGER: But we felt that, given this scenario, that that was an acceptable level, and that's what we -- we submitted.

MEMBER KRESS: Okay.

MR. HANLEY: This is Tim Hanley again from Exelon Nuclear.

The other open item with the staff is the large transient tests. Our submittal was based on ELTR-1 and ELTR-2. ELTR-1 calls for two large plant transient tests. One is an MSIV closure, if you're uprating greater than 10 percent from your current license power, and the other one is the generator load reject for uprates of greater than 15 percent above your current license thermal power.

I want to say ELTR-1 is a generic uprate

guideline or topical report that covers power uprates that include a steam dome pressure increase and those that don't. It doesn't differentiate the testing requirements between those two types of uprates, and a big part of our basis for not doing those tests is the fact that we are not increasing reactor steam dome pressure.

In fact, GE has since submitted another submittal to do constant power uprate EPUs that do not require those tests. Overall, our basis for not wanting to do these tests is they are, in fact, initiating large transients on the plant from the full power conditions. It's not warranted based on the way we're doing our uprate.

Essentially, all we'll be changing is the thermal power and the reactor and the steam line flow. All of the other main parameters of interest, which would be the SCRAM time, bypass valve response, relief valve response, are all unchanged.

With the limited changes to the inputs, the Oden Code that we've used to analyze the plant's response has indicated that the response would be within an acceptable level for the individual components that would be challenged during these tests.

So with -- having very little to gain out of performing these tests, and, in fact, running tests on operating reactors, we believe that it's better from a safety perspective not to run these tests.

MEMBER POWERS: I can't understand the plausibility of your argument for the MSIV closure. Can you explain a little bit on this load -- generator load rejection?

MR. HANLEY: Yes. In the generator load reject from full power, as the stop valves get 10 percent closed from their full open position, you get an anticipatory SCRAM. So the rods go in then. None of that has changed. So it's actually -- although the pressure transient has started to increase, the rods are already going in at that point.

The other thing important about the generator load reject, you still maintain bypass valve capability. We haven't changed the bypass valve response time, the bypass valve capacity, and once the rods go in you're well within your bypass valve capacity.

You do see -- we do see some increase in the peak pressure that you see in the vessel, because you do have a greater amount of steam flow that's being interrupted and a greater amount of power to

begin with. But the transient actually terminates very quickly.

And because we haven't changed those other inputs, the stop valve closure point at which you get the SCRAM, the SCRAM response time, bypass valve response time, it doesn't seem prudent to go ahead and run this test when there's very little to be gained from it.

Again, this isn't --

MEMBER LEITCH: In some of the reading here, it seemed to suggest that some of the justification for not doing the test was based on some testing done at KKL.

MR. HANLEY: KKL actually did an extended power uprate, did testing. The real justification was to show that the Oden Code that we're using adequately predicts the plant's response at uprated conditions. They compared the Oden results. They ran a KKL to the actual plant response, and it was -- conservatively predicted the response and did follow the trend of the plant's response for all of the parameters of interest. So --

MEMBER LEITCH: But KKL has a 100 percent bypass system. The four plants we're discussing are like 25 percent bypass?

MR. HANLEY: We're actually about 40 for -- 40 percent of our current, so it goes down to approximately 37 percent, something in that range. However, in the MSIV closure, your bypass valve capacity is irrelevant because you don't have bypass valves anyway.

MEMBER LEITCH: Yes, you're talking about the generator load reject system.

MR. HANLEY: For the generator load reject, the real issue is you get -- you get quickly below the bypass valve capacity, even at Dresden/Quad Cities. It reduces the pressure, because the bypass valve response time -- as the stop valves are going closed, the bypass valves don't open quickly enough to compensate for that.

So even at KKL they did see a pressure spike with the generator load reject. And the actual capacity of the bypass valve system doesn't -- is only in play for a very, very short period of time, because then you're down to decay heat that you're worried about.

And, really, the basis for that was to show Oden can predict both plant responses before and after EPU, and that was part of our basis for not doing it. Oden says that we'll stay within the

parameters that the components can operate under.

MEMBER POWERS: Professor Wallis has trained me to understand that when somebody says that a code conservatively predicts something that it predicts it rather badly, but that it's high. Is that the case here?

MR. HANLEY: Actually, I believe we have some backup slides on this. It does predict a higher value in most of these -- in all of these cases, but it is --

MEMBER POWERS: These are proprietary slides, so we're going to have to discuss these at -- some of the members have -- it looks like some of the members have some materials, but at this point --

MR. HANLEY: We can get that afterwards. And, again, this is an open issue with the staff.

If there is no more questions, I'll turn it over to Bill Burchill.

MEMBER ROSEN: Well, I expected at this point you would address the testing that you are planning to do for what -- based on your modifications of the reactor recirc runback.

MR. HANLEY: There is another section in the back that covers startup testing in general.

MEMBER ROSEN: Oh, okay.

MR. HANLEY: This was an open issue, so I'll address it when I come back to do that.

So I'm going to turn it over to Bill Burchill.

MEMBER WALLIS: Can you do this in about five minutes, Bill?

MR. BURCHILL: I will do that, sir.

MEMBER WALLIS: But I can't promise you there will be no questions.

MR. BURCHILL: My name is Bill Burchill. I'm the Director of Risk Management for Exelon.

There were no open questions from the subcommittee meeting, but we were asked to provide a summary of our risk impact study. What I'm going to do -- if you could go back a slide. I don't want to get onto this one yet.

I want to report the principal results of the -- both qualitative and quantitative evaluations. For the quantitative evaluations, we used CDF and LERF as our figures of merit, and we did principally use the full power internal events PRA, which had been upgraded in 1999 and has been reviewed by the BWR owners group.

The other evaluations did use some quantitative tools but did not do a full plant risk

evaluation.

We evaluated the impact of all of the changes that have been previously described in hardware, procedures, operating conditions, and setpoints. And, in general, we found no new accident types. We found no significant changes to accident scenarios. We found no changes to system dependencies and no vulnerabilities that were introduced by the EPU.

There were very limited impacts that could, in fact, be quantified primarily in the initiating event area and also in the operator response times.

The examples of effects that would, of course, come into play is the higher stored energy and decay heat load, operating the increased number of feedwater and condensate pumps, and more valves being needed for both overpressure protection and depressurization.

Now go to the next slide.

MEMBER POWERS: You said you found no new accidents introduced by this uprated --

MR. BURCHILL: That's correct.

MEMBER POWERS: It seems to me I received some material which I -- naturally I can't put my

hands on immediately that says that the turbine runback does introduce some -- a new accident.

MR. BURCHILL: It's not a new accident class, however. I mean, because we look at the impacts of what the turbine runback would produce, and we also look at the impacts of the failure of the turbine runback when called upon. And they are equivalent to scenarios that are already in the PRA.

Now, this slide is more detailed than will fit in five minutes, but I want to point out that we did look at all of the technical elements of the PRA, particularly, as I said, the initiating event frequency, success criteria, system changes, and operator response times.

We used sensitivity studies to evaluate these, and it also provided a guide for updating the PRA for our next cycle of update. This slide summarizes the key quantitative results from the full power internal events PRA.

And you can see that there are three basic areas. One is the area of the initiating event frequency. There is an impact based on the fact that we're running one more condensate pump and one more feedwater pump, and the very first line shows that there is a contribution there.

This contribution is actually conservatively stated here, because we didn't take credit in this case for the recirc pump runback feature. That was not designed at the time that we had this evaluation completed. So that evaluation, if we were to take that into account, would essentially be a zero impact.

The next five are in the operator action category, and in each case the impact is a slightly decreased time for the operator action. The actions we're talking about here are generally in the 20- to 30-minute timeframe, and the decrease is on the order of four to five minutes in those cases. So we evaluated those analytically. We took those impacts and determined what the new human error probabilities would be.

MEMBER WALLIS: But all of these numbers are 20 percent. Presumably there's some calculation? It's strange they all come out to be the same.

MR. BURCHILL: Most of them are times that are either 20 minutes down to 16 or 25 down to 20.

MEMBER WALLIS: So they're all the same 20 percent.

MR. BURCHILL: Yes.

MEMBER WALLIS: So this is also -- this

must be proportional to the power uprate or --

MR. BURCHILL: Well, we assumed conservatively, and I'll use that word with care, that we -- that there was a linear relationship between the power increase and the time reduction. Beyond that, we cranked it through the normal evaluation techniques for ATPs.

The last one is the change in the depressurization success criteria. This was probably the largest individual change in success criteria area. Where previously one valve would be sufficient for depressurization, in the case of the uprated power two valves were required. And this obviously introduces a change to both the success criteria. It also introduces some new failure probabilities, and, in particular, changes our evaluation of the common cause failure effect.

The next slide summarizes overall the quantitative results. Again, I point out, as was pointed out earlier, the plants are similar, but they do have differences in equipment and that's the principal reason for the differences in base values.

The first group of numbers is the base, CDF, and LERF. The second group of numbers that are expressed in percent are the impact of the EPU. The

absolute value impact, while it's the combination of a number of individual contributions, is essentially the same for both plants. It's about 2.4 times 10^{-7} per year differential on CDF.

MEMBER ROSEN: This is just with -- looking at internal events.

MR. BURCHILL: That is correct, sir.

MEMBER ROSEN: Not fire or anything else.

MR. BURCHILL: That's correct.

So the difference in the five to 10 percent that you see here is entirely due to the difference in base value. The LERF numbers may look to some of you who are familiar with this to be fairly high in comparison to the CDF numbers. Generally, for a MARK-1 containment, one would expect a LERF on the order of 10 to 20 percent of CDF.

These numbers are considerably higher simply because of the conservative methodology that we used to calculate LERF. It's a methodology endorsed by the NRC staff in Reg. Guide 1.174, and it has served our needs for our applications to date.

Now, this is not a risk-informed application, but -- so, as such, there are no specific regulatory acceptance criteria. We did benchmark the results against what are published in Reg.

Guide 1.174. What we found was that the delta CDF is in the very small risk change region, and the delta LERF is in the small risk change region.

The delta CDF is deep within the small risk change region, the very small risk change region, by about a factor of four. The delta LERF is just barely into the small risk change region. And if one takes into account what we believe is the degree of conservatism in that calculation, it, too, would be in the very small risk change region.

VICE CHAIRMAN BONACA: Just a question I have. What is the ATWS contribution to the -- to your CDF, 2.6 and 10^{-6}. What's the --

MR. BURCHILL: If you add up all of the scenarios that go to ATWS, it's about in 10 percent of the scenarios.

VICE CHAIRMAN BONACA: Ten percent of 2.6 and 10^{-6}.

MR. BURCHILL: Right. Okay. If I go to the last slide, these are the qualitative risk evaluations that were performed, and I want to quickly point out that we did use some quantification in these. We do have a fire PRA model for both plants. That was developed in support of the revised IPEEE submittal a couple of years ago.

We did examine the top 10 scenarios in both PRAs, and those represent about 90 percent of the CDF. We found only minimal impact, primarily on operator action times that were long term. So, effectively, there was a negligible impact.

For seismic, as has been mentioned, we only have a seismic margin analysis on both plants. We did a qualitative evaluation of the results that were previously reported in that analysis, principally with respect to whether any of the fragilities would be changed or impacted by the increased power. We found no significant impact.

We did, in response to the staff's question, as has been mentioned, do one event-specific event tree to quantify the impact of this dam failure scenario that we talked about. And you're absolutely correct, there is no specific acceptance criteria. However, if we do map that scenario onto the Reg. Guide 1.174, while the base value calculated was 10^{-5} per year, the delta was 10^{-8} per year. So that actually falls well below -- you know, well into the very small impact range, even though the base is higher.

On the shutdown, that's all qualitative. And, again, we evaluated our defense-in-depth actions

that we take during shutdown. We found that the only thing that was impacted was long-term operator actions, and also a success criteria for alternative decay heat removal. But this is out in the 30-day ballpark, so some of the fallback positions on alternative decay heat removal would not be available until after about 35 days compared to about 38 days pre-EPU.

And, of course, we do have a configuration risk management program during shutdown to assure that any impacts are managed.

With respect to flooding, we do not have flooding in our current internal events PRA. We are installing it at this time. But the IPEEE studies show -- I'm sorry, the IPE studies show that flooding contributed only about one percent. So we looked at that and did not see any impact with respect to either new initiating events or increased initiating event frequencies.

So our conclusion from each of these other risk sources and operating modes is that the impact is acceptable. I'd be happy to answer questions. Otherwise, I will turn it over to Tim Hanley again.

MEMBER ROSEN: In all of the plant modifications, you're not stringing into a cable?

MR. HAEGER: There is one DC cable that we are stringing to improve the voltage at one of the reactor panels. As far as other cable for some of the mods, I think there has got to be some cable for that, I assume.

Ed, I'm looking to you for confirmation.

MR. BURCHILL: And I presume the question is based on impact on fire risk.

MEMBER ROSEN: That's right. That's where I'm going.

MR. BURCHILL: I understand. Right. I think in our examination of the top 10 scenarios I do not know if we looked explicitly at this new cable, but I would assume that the impact would be fairly small.

MEMBER POWERS: I would assume that if you strung new cable you'd have to go through and do another screening on your fire areas.

MR. BURCHILL: That would be true. But I would be surprised if this were being strung in an entirely different location than is currently being used.

MEMBER POWERS: Yes, I was --

MR. BURCHILL: For a similar function.

MEMBER POWERS: Well, I was thinking of

you --

MR. HAEGER: Actually, the cable I was referring to is just a redundant, parallel cable to reduce the voltage drop.

MEMBER POWERS: It changes the combustible loadings in the room at the very minimum, and it also then increases the cable tray loading. I mean, there has to be some reanalysis that has to be done.

MR. BURCHILL: If we were to go in to fully quantify that, that would be true. Any other questions?

MEMBER WALLIS: There is a -- is your friend here going to speak or --

MR. CONNELL: I can't tell if you have heard enough or not, but what I was going to say was on the cable -- and all of the modifications we always look at that, that's one of the checked off features. The major cable pulls for these modifications were the ones that -- 125 volt DC that Al had mentioned, and also for the pre-filters that we've added in the condensate demin area, and that is examined.

Of course, in that area it's -- that's all non-BOP equipment down in that area. But it does impact the fire loading in the area, and it is considered.

MR. BURCHILL: Yes. The fire loading impact on the risk would be extremely minimal. If they were really routed in different locations, that would be where you would --

MEMBER POWERS: Might have to do another associated circuits analysis.

MR. BURCHILL: I'm sorry?

MEMBER POWERS: Have to do another associated circuits analysis.

MR. BURCHILL: That would be done under the appendix. Well, it's -- this isn't an Appendix R plant, but it --

MEMBER ROSEN: There's a discussion in the staff's SER -- draft SER about the need to update the PRAs sooner than the normal cycle because of the extensive amount of modifications, both operational and hardware. Is that something you're going to do?

MR. BURCHILL: The plan at this moment is not to make an explicit update because of the results of these sensitivity studies. If we need to make an update, we have the basis to do that. What we would do is only update about six critical parameters in the PRA and then roll that into our online risk monitor.

The current plan is to actually incorporate those at our next update cycle, which

would put them into place in May of next year.

MEMBER ROSEN: May of next year.

MR. BURCHILL: Yes.

MEMBER ROSEN: Rather than two years as stated in the draft SER.

MR. BURCHILL: I don't know what the draft SER says about our update cycle, but it would be May. That's our next deadline for periodic update.

MEMBER ROSEN: May of 2002.

MR. BURCHILL: Correct.

MEMBER WALLIS: Are we ready to move on or --

MR. BURCHILL: I'll turn it over to Tim Hanley, then, who will talk about the training and testing.

MR. HANLEY: This is Tim Hanley again. I'm going to cover the training and testing that we're -- we have done and are going to do during our power uprate.

We did extensive classroom training for the operators covering all of the aspects of EPUs, modifications, procedure changes, uprate operating experience. We did a lot of simulator training, started with a walkthrough of the simulator coming in at full EPU conditions, what the plant will look like

for the operators the first time they come to take the shift under EPU conditions, did some normal operation scenarios, swamping pumps, reducing recirc flow, moving control rods, and then did dynamic scenarios that were selected to highlight the differences and also the similarities between the operator actions for these transients and accidents.

They included recirc flow controller failure, loss of feedwater heating. We did do a turbine trip/no bypass ATWS and did an MSIV closure with a loop LOCA. And, really, the operator's response to that was that the -- it really doesn't change a whole lot working through the symptom-based EOPs that -- you know, they're monitoring parameters and taking actions based on what those parameters are, and their actions really haven't changed significantly.

For the testing, we're going to --

MEMBER LEITCH: Tim, did I understand you to say that the simulator has already been modified?

MR. HANLEY: All of this training has been completed at Dresden. At Quad Cities, our uprate outage is not until February. We're in the process during this week and next week of updating the simulator at Quad. We'll be doing our simulator

training, the final training cycle of this year, and the one before our February EPU outage. But we are following the same model as Dresden.

MEMBER LEITCH: So the down time on the simulator is not appreciable. It's only a matter of a couple of weeks?

MR. HANLEY: That's correct.

MEMBER LEITCH: Yes, okay.

MR. HANLEY: That's correct. And that was planned into our training cycle before we began the year.

For our testing, we'll be following the ELTR-1 testing for the incremental testing. We'll actually be starting at 90 percent of our current rate of power, getting a set of data there, going up to a constant flow control line at 100 percent power, increasing power once a day in a three percent interval, gathering the data, comparing it to the acceptance criteria, before we move on the next day.

We do have a dedicated test team led by an SRO at each site, and we are sharing resources between the two sites, so we capture any lessons learned from Dresden as we go to Quad Cities.

We are a two-system control system where particularly testing is the pressure control system

and the feedwater level control system. We're changing where the pressure control system will control pressure, so -- because we'll have a lower turbine throttle pressure than we currently do. So it will be controlling at a different band.

And then three-element control will obviously have different inputs for feed flow and steam flow, if we want to do explicit testing on the stability of those systems and their response to changes in those parameters.

We do have -- since we're increasing the flow significantly through the feedwater and steam piping, we'll be installing vibration monitoring, both inside and outside of the drywell, and monitoring vibration data on both of those systems.

The acceptance criteria was established from the ASME stress analysis limits, and that's the basis of determining acceptability of the vibrations we see on those lines.

Specifically asked about earlier was modification testing, particularly on the recirc runback. We are doing -- we'll do unique modification tests for each of the mods that we're doing for EPU. For the recirc runback, there's really a series of modifications that were put in as a reliability --

plant reliability because we're using the extra condensate feed pump.

One of those is the recirc runback. We'll be testing the recirc runback, verifying the speed is the speed that the runback is what we expect. We'll be testing the entire logic train by a series of overlapping tests. We have some pressure instruments that -- for the feed pump low suction pressure that will be verified in the setpoints. And we'll verify the setpoints of the SCRAM once we reduce the SCRAM setpoint from eight inches to zero inches.

We do not plan on doing a feed pump trip at full power and watch the recirc pumps run back. The basis for that was we -- it's not a safety issue. We are not installing this mod. We don't take credit for it in any safety analysis. It's strictly to maintain the plant online in case you lose a feed pump or a recirc pump.

And in an effort to not cycle these large motors and pumps unnecessarily, we don't intend to do a dynamic test of that entire system at full power.

MEMBER LEITCH: Can we talk just a second about the SCRAM setpoint, level setpoint? You're reducing that by --

MR. HANLEY: Eight inches.

MEMBER LEITCH: -- from eight inches to zero?

MR. HANLEY: To zero, that's correct.

MEMBER LEITCH: And that only -- that reduction only occurs when there's a trip signal into one of the condensate pumps. Is that correct?

MR. HANLEY: No, no. That's a -- strictly an RPS setpoint change. Yes, the RPS setpoint is at plus eight inches right now. We've got, as part of our EPU submittal, to reduce that down to zero.

MEMBER LEITCH: And that will be in all of the time. That is --

MR. HANLEY: That's correct. It doesn't set down -- it'll always be zero.

MEMBER LEITCH: Okay. I misunderstood. Thank you.

MEMBER ROSEN: Well, there is the law of perverse consequences, which says that if you don't test something that then surely something will be a problem. You're balancing off two -- two competing issues -- one, the need to -- the desire to not cycle these large motors and pumps versus the desire to fully test the system which may have some unknown failure mode. And it's always a judgment call, isn't it, at the end of the day.

MR. HANLEY: And that's right. That -- you've got to balance, you know, the long-term reliability of the equipment, not only just the motors but also the seals on the pumps get rattled when you trip them. The recirc pumps will be running back, which can have negative effects on the seals on the long term.

But, really, test -- tripping a feed pump from full power really does only test one facet of it. That just verifies that it worked under those conditions. The overlapping testing that we'll do of the complete logic train is what we're relying on to shake out any unexpected consequences. Does this runback come in when it's not supposed to?

So it's those facets, and that's why we have a unique mod test for the modification, to ensure that there aren't any unexpected consequences out of it.

Currently, right now our procedures will tell the operators, if you lose a feed pump and a standby is not available, what they do is reduce recirc pump speed to --

MEMBER ROSEN: But they do that manually.

MR. HANLEY: They do it manually. So the action really isn't changing. We're just having an

automatic system that'll do it.

MEMBER ROSEN: And it's the automatic system that won't be tested.

MR. HANLEY: Well, we will be testing the automatic, but we won't be doing it at full power. We'll test the recirc pumps' scoop to speed runback is what we have designed it to be, and that it comes in when you get a feed pump trip and the other inputs, which is 20 inches reactor water level. We will be testing all of those things.

Really, the only thing we're not going to be testing is, does that keep you from hitting zero inches and getting a SCRAM in? Because we won't be doing it from full power. We'll be doing it in, like I said, incremental steps as part of the outage or part of the startup testing.

MEMBER WALLIS: Can we move on, Steve? Can we move on? Are you satisfied?

MEMBER ROSEN: Yes.

MEMBER WALLIS: Do you have a bottom line to show us?

MR. HANLEY: Yes. I'm going to turn it over to John Nosko for our conclusion.

MR. NOSKO: Thank you, Tim, and our thanks again to the Committee for listening to the

presentation.

Just to quickly summarize, our application for the extended power uprate has followed the standard approach for extended uprates using a constant reactor pressure. We've conducted extensive analyses using accepted methodology, conservative inputs. We have found no significant impacts on the plant response or system integrity. The changes in plant risk we characterize as minimal.

And our conclusion, as you can see, is that plant operation is acceptable at EPU conditions. And with that, we thank you for your time.

MEMBER WALLIS: Thank you.

MEMBER LEITCH: I had just a couple of questions. One relates to the basis of the tech spec changes. And in the Dresden tech specs, there is a sentence that presently exists where it says, "No credit is taken in the safety analysis for the isolation condenser system operation."

The proposed change is that sentence is stricken, which implies that now credit is taken for the isolation condenser operation, is that correct? Which is -- it says the isolation condenser system is not a safety-engineered feature system, not an engineered safety feature system, and no credit is

taken for the safety analysis, or IC system operation. And it proposes striking that sentence.

MR. POST: This is Jason Post. We do not take credit for the isolation condenser. As we did the common plan and looked at the common features of the plants as we did the analysis, the isolation condenser was not used in the safety analysis for LOCA and ATWS and those types of analysis.

MR. HAEGER: Yes, I think the sentence is struck because in the loss of feedwater we did use the isolation condenser as modeled in there to -- to respond to that event.

And, Mark, maybe you can amplify it further. But I think we were just uncomfortable with that statement in there in regards to the transient analysis.

MR. KLUGE: This is Mark Kluge from Exelon. Al is correct. The use of the isolation condenser and the loss of feed transient is discussed in the current FSAR. What Jason is referring to is that the safety analysis for that event runs out only until the parameters of interest have turned around.

And in that timeframe, the isolation condenser is not credited to mitigate that transient. It's only used as a -- in terms of long-term decay

heat removal once the transient itself has recovered to the point it will.

MEMBER LEITCH: So to paraphrase that, am I hearing that this is mainly to -- in cleaning up the tech spec basis rather than a --

MR. KLUGE: It would make the tech spec basis consistent with the FSAR.

MEMBER LEITCH: Okay. And I guess a similar question related to a statement here that talks about relief valves. It says these valves are sized assuming a turbine trip, a coincident SCRAM, and a failure of the turbine bypass system. And the proposed changes would strike that sentence. Wouldn't that still be the case?

MR. KLUGE: No. Again, this was the original sizing criteria for the relief valves as discussed in the FSAR. For the EPU condition, that sizing was meant to prevent lifting any of the safety valves. For the EPU condition, although all the transient and accident analysis results are acceptable and meet their acceptance criteria, there is a potential that under absolutely limiting conditions we could lift a safety valve.

So, again, we're changing the bases to be consistent with how the FSAR will read in this case

after EPU.

MEMBER LEITCH: Okay. I understand. Thank you.

MEMBER WALLIS: Are there any more questions? Can we move on to the staff's presentation? We thank you again.

We have run a little late. I'm sorry, Mr. Chairman. Doing the best we can.

CHAIRMAN APOSTOLAKIS: I'm sure this is not your best.

MEMBER WALLIS: It's not the first time. I just assume that we can make adjustments to the people we're going to see over lunch break.

CHAIRMAN APOSTOLAKIS: Perhaps the staff can --

MEMBER WALLIS: John, are you ready to go?

MR. ZWOLINSKI: A few logistics.

MEMBER WALLIS: Are you ready now? John, are you ready?

MR. ZWOLINSKI: Yes, sir.

MEMBER WALLIS: Please begin.

MR. ZWOLINSKI: Thank you, sir, very much. Good morning or good afternoon. I'm John Zwolinski. I'm the Director of the Division of Licensing Project Management, NRR. We're here to present our review of

the extended power uprate on Dresden and Quad Cities.

I wanted to take just a couple of minutes and beg your indulgence. I note the time is running on. Before we start our presentation on Dresden and Quad Cities, I'd like to reflect for just a couple of minutes on Duane Arnold. Your letters obviously caught the attention of not just myself, the staff, but my senior management.

We've issued the Duane Arnold amendment, and this is the safety evaluation for that amendment. I'm going to send this over in the near term. I recognize people's schedules and it may be difficult for you to take the time to actually take a look at this. But this is a foundation for us as we go forward, that indeed we took your comments, concerns in your letter, and in so many words I think we've incorporated those in this product.

I would even go so far as to be happy to line in and line out if that would help the Committee to see the significant changes the staff made.

I'd like to emphasize that the staff has performed a comprehensive review for Dresden and Quad Cities, much along the lines of what we did with Duane Arnold. We've been very sensitive to -- to assure that we understand what the staff really did and

characterize that accurately, whether we performed independent analysis, the rigor of that analysis, what exactly did we do to confirm that the licensee's application warrants acceptance.

I'd like to emphasize that in the approval of the Duane Arnold power -- extended power uprate not only did I personally spend a lot of time ensuring this product met management expectations, I had Tad Marsh, my Acting Deputy, independently go through this product in great detail to meet not just the expectations of our management team but those that we were challenged by the Committee.

We made a detailed presentation to the Subcommittee on Thermal Hydraulic Phenomena a couple of weeks ago. I believe it was October 26th. A review of the application was performed, as I said, in a manner similar to Duane Arnold. However, our review also covered unique features associated with Quad Cities and Dresden.

I'd like to remind the Committee that our review methodology that we used on Duane Arnold and continues to evolve is predicated on the lessons learned from Maine Yankee. All areas affected by the power uprate have been reviewed and evaluated by our staff. The staff has critically examined the

methodologies and their application for this power uprate.

We have concluded that all analytical codes and methodologies used for licensing analysis are acceptable for this application. Although we reviewed information in many areas, we intend to focus our presentation today on areas we believe to be the most important to the power uprate.

In that regard, unless there is anything on the Duane Arnold issue, I'd like to move forward with the presentation on Quad Cities and Dresden. Specifically, with me, Larry Rossbach, the Lead Project Manager for Dresden and Quad Cities power uprate reviews. Larry is our NRR Project Manager for Dresden plant.

Also at the table is Stu Bailey, Project Manager for Quad Cities. Larry will give an overview of the review process used for the application and the order of presentations. He will also introduce the other presenters at the table.

Noting the time, we'll move as quickly as we can. I am sensitive to be responsive to any questions or concerns that the Committee may have.

Larry?

MR. ROSSBACH: Thanks, John. Larry

Rossbach, NRR Project Manager for Dresden.

I just want to briefly summarize our review approach. The staff used as guidelines in our review the General Electric topical reports covering generic guidelines and generic evaluations for BWR extended power uprates referred to as ELTR-1 and ELTR-2. These licensing topical reports have previously been accepted by NRC as acceptable guidelines for power uprate applications.

Staff also relied on the standard review plan and the safety evaluation for Monticello Nuclear Generating Plant power uprate as a guide for the scope and the depth of our review. The staff's --

MEMBER WALLIS: The standard review plan is not a standard review plan for uprates. It's some other kind of standard review plan.

MR. ROSSBACH: It is. It's a general standard review plan --

MEMBER WALLIS: Right.

MR. ROSSBACH: -- that we would use, right, for any of our reviews.

The Dresden and Quad Cities power uprate reviews were done in parallel with the Duane Arnold review, which this Committee reviewed about a month ago. In many cases, we used the same reviewers.

Where needed, the staff requested additional information to complete our review. Staff also completed three audits associated with our review. One of these was done by the Reactor Assistance Branch. They audited the global nuclear fuels analyses. This was done at the Wilmington, North Carolina facility.

Our Probabilistic Assessment Branch staff audited the licensee's risk assessment review at Exelon's Midwest offices. And the plant systems reviewer audited the analysis done in his area at the Dresden site. We prepared short summaries of review in several areas -- the reactor systems area, plant systems review, material degradation issues, and risk assessment review.

So with that, I'll turn it over to the first presenter, Ed Kendrick, who will discuss the reactor systems review.

MR. KENDRICK: I'm Ed Kendrick of the Reactor Systems Branch of NRR. During the previous subcommittee, Ralph Caruso, our Section Chief, presented details of our analysis of the reactor and fuel systems performance. I want to cover a few things.

The first -- a review scope -- we want to

point out the review scope, what I would call generic reviews, that since 1991 all of the new fuel designs from GE have been audited for compliance with the approved fuel design criteria, each -- from the initial nine by nine to the current GE 14.

And the maximum extended load line limit analysis has been reviewed and approved for a number of BWR plants, so these -- these areas are essentially covered generically. And although it's the first application of these for Dresden and Quad, there has been extensive review before this application came in.

The specific review scope for Dresden and Quad Cities covered the review and evaluation of the record of performance sections of the EPU safety analysis reports submitted by the licensee to GE, licensing topical reports.

We also had an onsite review at GE Wilmington. The purpose of this one was to ensure continued compliance with the approved analytical methods and codes, the procedures, and we also evaluated the specific Dresden and Quad Cities reload core safety analyses.

I'd point out that changes to the tech spec safety limit minimum of critical power ratio were submitted separately and were reviewed separately.

And that's why you don't see it in the EPU SER.

MEMBER POWERS: Explain to me under fuel evaluations how it is that you know that the fuel -- these new GE fuels will tolerate the power inputs associated with ATWS oscillations.

MR. KENDRICK: Okay. The fuel design is audited. We actually have done some calculations of the GE 14 fuel. The capabilities of the bundle to generate the power and stay within all required thermal limits has been confirmed. The ATWS scenario, the bundle, has actually been optimized for stability.

It is more stable than the previous nine by nine and ten by tens. And this satisfies the criteria for the ATWS rule.

If there's no more detailed questions on that, I think we'll answer any specifics --

MEMBER POWERS: Well, specifically, what we asked the applicant earlier today was how much power was it going to be putting in in the form of these oscillations as he tried to recover. He indicated something on the order of 70 to 80 calories per gram. We asked him, why does he think that the fuel will stand up to that.

He indicated that that was within the criteria that you sat. That is an accurate statement,

I believe. The criteria is 180, but the experimental data have come to question the adequacy of that.

MR. KENDRICK: Right. The -- in fact, that's being addressed under the extended burnup program. The --

MEMBER POWERS: Does the extended burnup program have GE 14 fuel?

MR. KENDRICK: Not GE 14, but the -- the question is primarily that of cladding performance, not fuel performance. We look at the fuel design, the fuel that is capable. The cladding that's used for this bundle design is less sensitive to corrosion and spallation, which have been the key initiators for the RIA with the low enthalpies that have been observed.

MEMBER POWERS: So they are testing this particular cladding?

MR. KENDRICK: I don't know if this cladding will be tested. But for the GE 14, the cladding material of that type will be tested. So this is an ongoing program, and, you know, coolant chemistry, cladding treatments, all of these are -- you know, are being used to address this.

An overview of the -- review of emphasis considered that there was no increase in the reactor dome pressure or in the core flow, but that the EPU is

achieved with a flatter radial power distribution and higher average bundle powers.

Again, it has come into question, what does the flatter power distribution do? It's a matter of concern. We look at this when we do the onsite reviews. We look at the actual calculations for the -- the initial calculations for the core performance. To do that, we examine their equilibrium bounding core analyses. And then the question was, okay, how do you get there?

Normally, the first transition cycle may be the most challenging, so we were able to review the initial -- the transition cycle calculations. Indeed, in some areas, you were closer to the limits. We're still within all of the thermal limits.

MEMBER WALLIS: I asked Exelon earlier about this business of the radial peaking factor, which they said was the ratio of bundle power of a bundle to the average power.

MR. KENDRICK: Right.

MEMBER WALLIS: And they said this hadn't gone up. We talked about 1.4, and so on. And then I asked him if this -- it was also true that the maximum bundle power itself would not be changed, and they said yes. But it seems to me that the -- if the

higher average goes up and the ratio of maximum average is the same, then the maximum must also go up.

MR. KENDRICK: The peak bundle power essentially does not change. You have more bundles that are operating closer to that peak.

MEMBER WALLIS: So the peak doesn't change but the average changes. In that case, the average goes up. Then, in that case the radial peaking factor must go down if it's the ratio.

MR. KENDRICK: Right.

MEMBER WALLIS: When they were talking about it going up. I don't quite understand the --

MR. KENDRICK: Well, they were showing the bundles above the core average. There are more of them that are operating --

MEMBER WALLIS: And they couldn't find the 1.4.

MR. KENDRICK: Well, but it has been 1.5 or something to have been -- to be consistent with the logic that I'm trying to pursue here. Well, the -- there are more bundles that would be -- could operate, as they indicated, at 40 percent above the core average.

MEMBER WALLIS: I know. I understand that. But the question is: how can you have --

increase the higher average bundle power and have the same average to maximum ratio and not increase the maximum?

MR. KENDRICK: A lot of the analyses are done where the maximum bundle is forced to be on the limits, somewhat artificial but -- but you come up with a control rod pattern and an operating strategy so that you put as many bundles as you can on limits.

MEMBER WALLIS: So if we did all of the right arithmetic, all of these statements would turn out to be consistent eventually?

MR. KENDRICK: Yes. The core average -- relative power distribution and -- the average core power is going up by 17 percent in absolute terms.

MEMBER WALLIS: All right. So in that case there, the ratio of maximum to average will presumably have to come down in order to stay at the same maximum by quite a bit.

MR. KENDRICK: Right.

MEMBER WALLIS: And that was not evident from the Exelon presentation.

MR. KENDRICK: Okay.

MEMBER WALLIS: But you are assured -- you can assure me that the maximum bundle power is still the same as it was before in --

MR. KENDRICK: We're still within the kilowatt per foot limits that we were before.

MEMBER WALLIS: You're within the limits. Has it increased?

MR. KENDRICK: It has increased slightly.

MEMBER WALLIS: Slightly.

MR. KENDRICK: But, again, there is still -- they're within the fleet. There are other reactors that are operating at higher powers, absolute powers.

MEMBER WALLIS: Well, that's another question, though. Okay. So, anyway, it's within the limits.

MR. KENDRICK: Yes. Within all of the thermal limits.

MEMBER WALLIS: Okay. Thank you.

MEMBER KRESS: I was concerned that the flatter profile would increase the carryover for ECCS injection. Did you guys look at that?

MR. KENDRICK: We looked at that. We heard the -- essentially the same presentation that you heard, and it seems reasonable. We haven't -- the latest thing that is also new to us, too, and we haven't evaluated that, that will be in the SER --

MEMBER KRESS: Okay.

MR. KENDRICK: -- the final SER. So we

did look at the -- all of the safety performance for both this equilibrium core and for the initial core. As discussed during the subcommittee, we checked that the capability of the slick system, Boron injection system, to perform the design function at the maximum system pressure was very -- we determined that for Dresden-2 everything was okay. For other units, some modifications may have to be made to the relief valve.

Our basic conclusion was that after our review of the report and our own site reviews, the licensee's submittal with the GE power uprate SER and with their response to our RAIs and with their onsite review, they demonstrated that Dresden and Quad can operate safely at the EPU conditions during steady state, AOO, and accident conditions.

The design basis analyses were done with approved methodologies, and we've verified that none of the assumptions in those approved methodologies have been challenged.

Cycle-specific analysis performed for Dresden demonstrates that you can achieve a core and approach the equilibrium core, for which much of the analysis was done. And the EPU meets all applicable NRC regulations.

MEMBER WALLIS: But not only can be

operated but will be operated.

MR. KENDRICK: It will be operated because if -- in the, say, unlikely event that they couldn't achieve the power due to something down the line, the core will still be protected. And we convinced ourselves that all of the safety flections and that the thermal limits would be met.

Any questions on how we conducted our reviews?

MEMBER WALLIS: Are you concerned about the 1600 degrees limit being met exactly?

MR. KENDRICK: Yes. As Ralph Caruso indicated during the subcommittee meeting, we challenged this and effectively asked if they had to go through a number of iterations, and were told that they didn't, but if they did it's the acceptance criteria. And as I indicated, the acceptance criteria was established with a number of conservatisms which --

MEMBER WALLIS: I guess they gave what I'm not sure is the right answer. I mean, they said that they didn't want to go through another calculation because they've already -- I think they implied that it might show a different answer which would not be so favorable.