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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUBCOMMITTEE ON ESBWR DESIGN CERTIFICATION

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WEDNESDAY,

OCTOBER 3, 2007

VOLUME II

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

MEMBERS PRESENT:

MICHAEL CORRADINI Chairman

JOHN D. SIEBER ACRS Member

OTTO L. MAYNARD ACRS Member

DENNIS C. BLEY ACRS Member

JOHN W. STETKAR ACRS Member

WILLIAM J. SHACK ACRS Member

SAID ABDEL-KHALIK ACRS Member

DANA A. POWERS ACRS Member

NRC STAFF PRESENT:

ILKA BERRIOS

RICHARD McINTYRE

STEPHEN ALEXANDER

FRANK TALBOT

AMY CUBBAGE

JOSE HAMZEHE

IAN JUNG

SANG RHOW

CLIFF MUNSON

BRAD HARVEY

ANDREA JOHNSON

KEN SEE

MOHAMMED SHOUABI

ALSO PRESENT:

JIM KINSEY

DAVID HINDS

RICK WACKOWIAK

IRA POPPEL

MARK HARVEY

DAVE HAMON

KATHY SEDNEY

BILL IRWIN

RICH MILLER

JOHN STRYHAL

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P R O C E E D I N G S

8:32 A.M.

CHAIR CORRADINI: Let's come to order. Let me go through my normal introduction. This is a meeting of the ESBWR Subcommittee. My name is Mike Corradini, chair of the Subcommittee. Other ACRS Members in attendance or will be in attendance are Said Abdel-Khalik, George Apostolakis, Dennis Bley, Mario Bonaca, Otto Maynard, Dana Powers, Jack Sieber, Bill Shack, and John Stetkar.

Tom Kress is also attending as a consultant to the Subcommittee. Gary Hammer of the ACRS Staff is the Designated Federal Official for this meeting.

The purpose of the meeting today is to review and discuss the Safety Evaluation Reports with open items for several chapters for the ESBWR design cert. We will hear presentations from the NRC Office of New Reactors and GE-H Nuclear Energy America's LLC. Is that the correct way of saying it? Good.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register. Portions of the meeting may be closed for the discussion of unclassified safeguards and proprietary information.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, we request that participants in the meeting use the microphones located in the meeting room when addressing the committee. The participants should first identify themselves and speak with sufficient clarity and volume so they will be readily heard.

We'll proceed with the meeting, and I'll call upon Jim Kinsey of GE-H Nuclear Energy America to begin.

Jim.

MR. KINSEY: Thank you. My name is Jim Kinsey. I'm the Vice President of ESBWR Licensing at GE-Hitachi. I just wanted to give a couple of brief introductory remarks and then turn things over to our team to begin the chapter reviews.

First of all, I wanted to thank the Committee again for allowing us to move through this newly being defined process where we're looking at portions of the DCD and safety evaluations on a chapter basis. As you know, yesterday we did an overview for you of the ESBWR design, so really today is the first time we're getting into this process of individual chapter reviews.

Basically, the structure that worked out with the NRC staff for today's agenda and for future agendas covering individual chapters is that we've brought along members from the GE team that are primarily the technical leads for the individual chapter. They're being supported and supplemented by a regulatory affairs team member who was the primary interface with the NRC staff as the chapter open issues were being resolved. So that's the typical makeup of a chapter team.

And our intention today would be to provide a discussion of key attributes of DCD Revision 3 which was the basis for the SER. We can give you a brief sketch of any major changes that may have occurred between DCD Rev. 3 and 4 and after providing that overview, then we would intend to turn things over to the NRC staff to continue with their discussion of the chapter.

So with that in mind, I'd like to introduce Mark Harvey who is the quality manager in our new plant projects area and Kathy Sedney who is the regulatory affairs chapter engineer for Chapter 17. And I'll let them step through the presentation, unless there are any questions at this point.

Thank you very much.

CHAIR CORRADINI: Thank you, Jim.

MR. HARVEY: Let's go to the first slide. The first thing I'd like to do is just give a brief outline on the areas that I'll be covering today. I'm going to start with a Chapter 17 overview just to highlight some high-level comments; a summary of the RAIs, a summary of the confirmatory items, and our plan and schedule for addressing any open items.

Okay, the Chapter 17 overview. Basically, what we've done is we have used our approved quality assurance program. That's the GENE QA program description, as you see on the board, which establishes the overall quality assurance requirements that will be implemented during the ESBWR design. Now if you look at the next couple of bullets, what we have is the high level program and then we have the implementation. So we have a quality assurance plan, that's the NP2010 COL Demonstration Project QA Plan which talks about how we're going to implement those quality assurance requirements internally. And we have NEDO-33181 which defines the supplier and sub-tier supplier quality program requirements that we're going to impose. So that's how we ensure that our quality requirements get passed up down to our sub-tier suppliers. So that's our implementation program.

And each of these documents has been reviewed during NRC inspections and I'm sure the NRC will be speak to that.

The GE-H quality assurance responsibilities are compliant, will be compliant with the COL applicant holder and QA program requirements during construction and operation. So we're ensuring that our QA program requirements meet the needs of the COL applicant. And the overall project quality assurance program description is, in fact, the COL holder or applicant responsibility.

Next slide, please, Joe.

Okay, part of Chapter 17, a significant

part of Chapter 17 is, in fact, the Design Reliability Assurance Program, the D-RAP, which transfers into an O-RAP and it's really a maintenance rule for design, you know, to simplify things. But what it really does it assures that important ESBWR, reliability PRA assumptions are considered throughout plant life. And it's the baseline by which the reliability programs that are developed subsequently are derived from and that includes -- this includes risk-significant SSCs that provided defense-in-depth for result in significant improvement in the PRA. And once the site-specific D-RAP is established and risk-significant SSCs are identified and prioritized, the procurement fabrication construction and pre-op testing will be implemented in accordance with the COL holders, D-RAP and verified through the ITAAC process.

Okay, overall, a quick summary of the RAIs, we've had 23 RAIs and supplements for Chapter 17. Twenty-two of those RAI responses have been submitted and 21 are considered resolved. We have one open RAI still in progress and that's open item 17.4-1 and that has to do with the D-RAP. And that's to identify a comprehensive list of risk-significant SSCs within the scope of the D-RAP at a later phase of development of the D-RAP.

The first bullet you'll see is a requirement and that's that the applicant which would be GE-H, must identify and prioritize the list of risk-significant SSCs within the scope and what GE-H plans to do is to convene an expert panel in January of 2008 to facilitate development of that list and we're going to submit to the NRC at a time subsequent to convening that expert panel.

MEMBER POWERS: How do you decide on an expert panel?

MR. HARVEY: That's -- we -- let me actually defer that, if I could, to our experts on that.

MR. KINSEY: David Hinds.

MR. WACKOWIAK: Rick Wackowiak from GE-Hitachi. Could you repeat the question?

MEMBER POWERS: I just wondered how you go about constituting an expert panel, who you select, what are the criteria for selection, what kind of breadth of opinion are you looking for?

MR. WACKOWIAK: Right, and that's one of the issues that we've had in terms of why the expert panel hasn't been convened up through this point. The guidance that's out right now is basically the guidance for the maintenance rule and it asks for types of people that don't exist for a plant that hasn't been designed or hasn't been built and operated.

So we have operations experts from our -- from some of our customer utilities and we have other people that have been working in the maintenance area at utilities and in the design engineering at GE and at utilities. And we're going to do the best we can to put together a set of broad-based expertise for all these radiation protection people, our dose experts. And give them --

MEMBER POWERS: Are you going to try to get somebody on your dose panel that believes in hormesis and somebody that believes in linear no-threshold? I mean what kind of range of opinion are you looking for?

MR. WACKOWIAK: The specifics of that question go beyond any guidance that I've seen for developing a maintenance rule expert panel. We're planning on using the NUMARC 93-01 guidance for developing the panel. Now I would expect that we would have various points of view on that, but we were not planning on going out and picking hundreds of different specific items and making sure that we had a broad range of opinion on every one of those hundreds of items.

So I don't believe I can answer your question right now.

MEMBER POWERS: I was quite sure you weren't going to do hundreds. I was trying to find out where between 1 and 100 it lay.

MR. HARVEY: If I might just answer a little bit here. If we use the typical set up of an expert panel maintenance rule has been established, you're looking at about 15 to 20 experts on the team with a supplemental group based on if you don't have the necessary expertise, then you'll bring in technical experts that talk about specific issues, if indeed there is a challenge to that.

Now we plan on using people from operations, PRA, engineering, maintenance, getting a broad range of experience utilizing our customer base as well as our internal people. We're also considering that as we go through our staff development at GE.

MEMBER POWERS: I thought that you said

the interesting thing there. You said we're going to look at our customer base as well as GE. How do you -- how much do you want customer base? How much do you want --

MR. HARVEY: Well, we're soliciting input. We're taking a look at what constitutes an expert panel. What we've done and this isn't an answer that really is off the cuff because what we've done, we've entered this action into our correction action system. We have corrective actions assigned to develop the team and convene the team. Now that will go through a management review as far as who gets selected onto the team and it will have to go through a rigorous approval process to make sure that we do have the right people on that team, but I'm sure that -- well, I don't want to speak.

David, if you want to talk about how we're addressing the customer base?

MR. HINDS: Yes, this is David Hinds from GE-H. Just again, repeating a little bit of what Mark had mentioned as the key requirement is that we have a broad base of varying skills across the skills that support the plant such as operations, maintenance, engineering, as opposed to -- and what Mark was referring to, if necessary, will include in that our customer base. We do have a broad range of skills now that we've developed in building our team within GE-H. We've hired in quite a number of recent plant operators, people who have had a license to operate boiling water reactors in the very recent past. And we will include them, include personnel with maintenance experience. If we don't have them within our employees, we would also consider those within our customer base. I think that's what he was referring to.

MR. HARVEY: Okay? All right, let's see. The next item was that we have, in fact -- I guess we wanted to make it clear that we're not waiting on the development of this expert panel to start working and developing a list of safety-significant or in-scope SSCs. We have developed an initial list of SSCs which will be an input to the expert panel and they will consider upon convening this team. And this list has been developed that's consistent with previous maintenance rule implementation in the industry. So we've gone out -- while we don't have a one-for-one obviously system-for-system, we look at application and general use.

We have incorporated operating experience. The data in our PRA assumptions has come from operating plants and failure modes from operating plants were factored into the assessment. Our current plant risk-significant issues -- oh, current plant risk-significant issues have also been addressed. And an example of that would be a spurious safety relief valve actuation caused by fire and that's just one. I don't want to attach any significance to that one particular item, but that's just an example of a current risk-significant issue that was addressed. And we've ensured that our design addresses this.

Joe? Okay, we do have two confirmatory items out that need to be looked at and they're both administrative in nature. The first is confirmatory item 17.4-15 which includes -- to include references to NUMARC 93-01, DCD. And that was addressed in DCD Rev. 4.

A second confirmatory item is 17.4-16 which adds a clarification statement to PRA importance measures. I don't want to take that out of context. What it said before was PRA important measures, so it was a minor clarification that we did address in DCD Rev. 4.

That's all I have.

MEMBER MAYNARD: I do have a couple of questions and I know a lot of this will come into the COL stage, but are you working with your potential customers or how do you transfer or how is a design documentation going to be handled or transferred? Who is going to be the keeper of the design control information?

MR. HINDS: David Hinds, GE-H. We have heavy involvement currently by our -- I'll say our first set of customers in the design process such that we've already begun some of that transfer of knowledge within members of the customer base. So they're involved in commenting and reviewing the design as it progresses, so we're already developing a knowledge base within the customers which has already begun. And then in the actual sale of the plant, there will be an extensive transfer of configuration management documents to the customer such that it will have a full configuration management package, including drawings and full reference material, technical manuals, the whole configuration management suite available. And then we'll continue to work with them as far as training programs which are yet to be determined as the specifics of the training programs. But we've already begun heavy engagement with the customer base because we recognize it takes a period of time for knowledge transfer.

MEMBER MAYNARD: A couple of things there. It's also key to what is the official design information? Is it what the licensee has? Is it what the designer has? And that should all match up there and I think that transfer is important in how that's handled and who officially ends up with it.

The other thing I have is on drawings and stuff. I would assume that most of the design drawings for this generation plant would be computer design. How is that being controlled? In the past with -- a lot of it was hard copies was the official document. Now we're talking about an electronic copy and so a little bit on how that's controlled?

MR. HINDS: Yes, currently within GE-H, we have a full design, electronic design suite of tools, a commercially available product that does 3-D design, PNIDs, electrical, etcetera. We're controlling that within an electronic data base within GE-H and we will have to make that transfer over to the customers. We do not have yet a contract that would specify -- we have the capability to transfer it in paper form or electronic forum. So some of those details of what the actual customers will hold have yet to be determined based upon contractual agreements, but I would anticipate that we would -- that they would also have an electronic configuration management suite similar to what we have, but some of those are yet to be determined based upon contractual agreements.

But currently, the design basis of the plant is documented electronically and controlled through a series of electronic approvals and signatures and configuration management suite that is electronic.

MR. HARVEY: And the quality assurance function is engaged in routine oversight of that activity and periodic assessment to make sure that configuration management is maintained.

MEMBER MAYNARD: And on the safety systems and components, how far are you going down on what is safety related? And what I'm really getting to is you may have a pump that is safety related, but maybe not all parts of it are. Are you breaking it down at this point or are you --

MR. HARVEY: Right, you're asking if

you're going to the system or component level or down to the part level. I think there's a -- that's the whole purpose of pulling together this expert panel and making those types of decisions. So when we get the expertise pulled together on that team, we'll do that. However, I believe the initial cut and correct me if I'm wrong, David, but the initial cut is to focus at this point on the system level.

MEMBER MAYNARD: I notice that you have a program for commercial grade dedication. I'm just wondering is it in the design phase at this point? Have you really needed to or do you do any of that or is that primarily going to be for the licensee and the COL holder commercial grade dedication?

MR. MILLER: Rich Miller, from GE-H, I&C manager. We're not using commercial dedication up front. We're going to qualify everything by test or analysis and it will be up to the holder at the site to do commercial grade dedication.

MEMBER SIEBER: It's typically used for replacements? Dedication?

MR. IRWIN: Yes.

MEMBER MAYNARD: One other thing is on some of the inspections found that hadn't met some of your documents or some of your times for resolving a no performance or something, just curious on your thoughts on the inspection and what they found and your perspective on that?

MR. HARVEY: Okay, I believe you're talking about some of the recent inspection that I don't believe that was associated, and clarify for me please if that was an ESBWR or an assessment in San Jose. Because the corrective action system is common to both, obviously. But I just want to make sure I'm correctly answering your question here.

MEMBER MAYNARD: Well, I think there were three inspection reports here and I thought it was on the ESBWR. I don't know exactly where it was done, but you had during the final implementation had failed to meet certain requirements or did not document the revised completion for the ESBWR DCD verification when the schedule was not met and did not maintain an update to work plan detailed schedule for the ESBWR program.

MR. HARVEY: At GE-H we struggled with corrective action implementation over the last year. We've made significant inroads in our ability to identify and resolve corrective action, nonconformances in a timely manner. I think what you'll see is if you go through the NRC inspection reports, there were some isolated instances where if you look at the progression, I believe our performance has improved over the last 8 to 12 months.

I also think our self-identification of issues has significantly improved over the last 8 to 12 months to where we're actually self-identifying, being more critical and getting those, identifying those issues and getting them in our program ourselves. We've also instituted numerous changes to our corrective action program to improve our metrics and improve our ability to self-identify upfront rather than waiting until something goes overdue. So we're doing a much better job at managing our corrective actions. We don't have anywhere near the overdue items that we used to have.

Saying that, timeliness is only a small component of corrective action. Quality is, without quality, timeliness is really meaningless. So again, we recognize that corrective action is critical to our success going forward and we have instituted a corrective action program revitalization effort, which is a site-wide effort and it is geared towards refocusing the entire organization on the importance of corrective action.

I think we've come a long way. I think we're doing better and we're going to be world class.

MEMBER MAYNARD: On your corrective action program, do you have various levels when you're evaluating a non-conformance or a problem where some may require a full-blown root cause analysis?

MEMBER MAYNARD: Absolutely. It goes through a screening and prioritization program. If it is an Alpha-1 significance, it requires a root cause analysis. If it is an Alpha-2, which is a condition adverse equality with some level of significance less than a significant condition at an adverse to quality, that will require an apparent cost type of evaluation.

So each individual issue is looked at for significance and based on the significance, the appropriate evaluation is assigned along with obviously if we do CAP PRAs or corrective actions to prevent recurrence, if you have the significant edition adverse to quality.

MEMBER MAYNARD: And on your organization, I apologize if I missed it, what's a reporting relationship for QA within GE-H.

MR. HARVEY: GE-H QA reports, I am a direct line report to the General Manager of Quality. General Manager of Quality reports to Andy White. So it is a separate line. I am, there is a project staff and we are dotted line on the project staff, so Steve Kusick is the General Manager in charge of MPP and I am a direct report, not a direct report, but I am dotted line to Steve, so I support, I support Steve. But there is not direct line reporting to that. We report directly to Andy White.

MEMBER MAYNARD: I don't have any more questions.

CHAIR CORRADINI: Other questions? Thanks very much.

MR. HARVEY: Thank you.

CHAIR CORRADINI: So the staff is up?

MS. BERRIOS: Well, good morning. My name is Ilka Berrios. I am in the Office of New Reactors. Division of New Reactor Licensing. We have here Steve Alexander and Richard McIntyre.

The purpose of this presentation is to brief the Committee of the staff's review of the ESBWR for the application in this case, Chapter 17 Quality Assurance. During the presentation, we'll happy to answer any question from the Committee.

The review team for this chapter was myself. We have Rich McIntyre, technical reviewers and supporting reviewers, we have Steve Alexander, Frank Talbot, you can see him there, and Kerri Kavanuagh who cannot be here today.

Today we're going to be presenting the regulations that were used during the review and RAI status, a summary of the technical topics, open items and some COL action items.

The regulations that were used during the review include some federal regulations and you can see them there, safety is under the review plan.

For this chapter, we had a total of 19. GE said 23, counting the original RAIs, a total of 19. Eighteen of them are resolved and we just have one open item there which the technical reviewers are going to present.

Now I'm going to leave you with Richard McIntyre.

MR. McINTYRE: Good morning. My name is Rich McIntyre. I'm a Senior Reactor Engineer in the Quality and Vendor Branch for Boiling Reactors in the Office of New Reactors. I had the lead for Chapter

17, Quality Assurance and as Ilka mentioned, you could see the staff that was reviewed. Steve Alexander had the lead for the operations part of the Reliability Assurance Program.

What I'm going to say is going to be very similar to what GE said. That's good. We're together on the findings and conclusions, so you never know when you get here. You hope you're together, anyways. But as far as the Quality Assurance Program goes, as we reviewed the GE QA Program is based on the standard GE topical, the NEDO document, the revision 8. That topical was reviewed and approved by the NRC in a letter dated back as far as March of 1989. GE has been working off of that topical ever since then.

As they mentioned, there is an implementing QA program for ESBWR and we used that in combination with the topical during our review. As mentioned, we performed three implementation inspections of the ESBWR QA program in November '05, follow-up in April of 2006 and then kind of a close-out of the open issues in December 2006. I know you were asking some of the questions on the findings, and I'll just touch on corrective action. That was one of them when we first went in 2005. That was an issue that needed attention.

They were in the midst of formulating a new computerized correction action program and there were a number of corrective actions that hadn't received the initial screening within the 30 days and then some overdue. But as Mark said, as we went back in April, we issued another finding. It was still not there. It was improving, and by the time we got into December, we had seen a significant improvement in the corrective action program where we ended up, we closed out that open finding on corrective action.

MEMBER MAYNARD: In looking at those, to me all what I saw was primarily was not meeting dates, getting some things done in a timely manner. I didn't see where you had found anything that was a significant problem that had not been identified or that had been resolved incorrectly or something.

MR. McINTYRE: We did not. That's correct. We didn't identify any findings for inadequate technical evaluation. You asked about the ones that we did review as far as identifying the significance and doing the root cause when we did review those. There was nothing inadequate in the evaluation. It was really, there was the sheer volume of the correction actions, getting them into the program and getting them done in a timely manner, which is in a program like that had been transformed from San Jose to Wilmington with a limited number of staff. It was an important issue that they needed to get their arms around.

During the inspections, we had inspection related findings and requests for additional information by December 2006. All of the nonconformances had been closed out and the RAIs have been resolved. So there was no outstanding issues related to the quality program implementation. I guess that's what I wanted to stress. When we did our inspections, it was the implementation of the quality program, the topical. You had asked about commercial grade dedication.

We looked at procurement. At this point in time, GE was not procuring any components. The only procurement activities that we saw was services and you see, we had a finding on that concerning the level and the quality of their audits of some of the foreign suppliers. But there was no procurement of components, so there was no commercial grade dedication to look at in this point in time.

MEMBER MAYNARD: I wouldn't have expected any, but it was in there --

MR. McINTYRE: I just wanted to let you know that we were aware of that, and if there were any components, we would have looked at commercial grade dedication.

As far as the Chapter 17.4 on the Reliability Assurance Program, I'll probably go in a little more detail than GE did, but the D-RAP is the program utilized during the detailed design and specific equipment selection phase to assure that the ESBWR reliability assumptions of the probabilistic assessment are considered throughout the plant life.

The staff reviewed the ESBWR D-RAP and the associated D-RAP ITAC to verify that it met the regulatory requirements of the SECY 95-132 that Mark had mentioned and specifically item E for the Design Reliability Assurance Program. And that was done using our new standard review plan, 17.4 on Design Reliability Assurance Program.

We issued 15 RAIs related to the D-RAP and the D-RAP ITAC. Many of the RAIs requested GE to develop QA elements on the GE interfacing organizations, design engineering, and the PRA organization to address design change control process, procedures, records control, audits, nonconformances, corrective action, and corrective actions to implement an inadequate D-RAP program.

GE adequately addressed 12 of the 13 RAIs in the latest, in the section 17.4 of the DCD, dated February 2007.

In August 2007, the Staff issued the Safety Evaluation Report with open item 17.4-1. GE covered that pretty in detail, the open item. They need to identify the list of risk-significant SSCs within the scope of D-RAP and the D-RAP associated ITAC using the PRA methods. Further, GE, NEDO, the Reliability Assurance Program, GE is assembling the expert panel with experts in PRA, engineering judgment and operating experience to identify this list.

GE stated that the panel will meet and finalize this list of the risk significant systems and components in January 2008. The list will be maintained. It will be issued to us in a design specification and maintained in that. In concluding on the D-RAP portion, in accordance with the 17.4 of our Standard Review Plan, the NRO staff will review and approve the final list of the risk significance, SSCs, within the scope of D-RAP for ESBWR DCD.

At this point, I'm going to turn it over to Steve Alexander and then both of us will wrap it up at the end. We'll go through the list of the action items, the open action items.

MR. ALEXANDER: I'm Steve Alexander, and I'm actually with the PRA Operational Support and Maintenance Branch in the Division of Risk Assessment NRR, so I was consulting to NRO on this project. My involvement really stems from, I'm the guy in charge of the maintenance rule, and so since a lot of operational implementation of the reliability assurance program is related to maintenance rule, and even part of D-RAP is using some maintenance rule approaches to things. I got shanghai-ed to help them out with this, but I was happy to do it.

So what we came out of a process of the staff responding to SRMs from SECY-95-132 and modifying what we had in mind, the idea was that there was no such thing as an operational reliability assurance program per se, but there needed to be some kind of a process to continue and to maintain the reliability in the operations phase that was established, if you will, in the design phase.

So we came up with the idea that there are operational programs that could be used to implement reliability assurance process in the operations phase. Now we won't use the, I'm only using the dreaded O-word here, O-RAP, as a shorthand, but we recognize, of course, that it is a process implemented by operational programs. Specifically, those operational programs are going to be quality assurance, the maintenance rule, and as important, if not the most important part of it, is the underlying maintenance and surveillance programs themselves, the notion being that quality assurance program makes sure that all the maintenance gets done correctly, all of the various aspects that are applicable to maintenance.

The maintenance rule monitors the effectiveness of that maintenance. But with the QA and maintenance programs by themselves you could simply preside over a plant that's going to run itself into the ground. And so you have to actually do stuff to the equipment to maintain it: change the oil, filters, vibration, tighten things that get loose, the whole myriad of things that are involved and actually doing maintenance on something as opposed to just observing its performance or condition or monitoring that. So we think that's a very important part of the operational programs: quality assurance, maintenance rule, and the underlying maintenance and surveillance programs themselves including tech specs, surveillance, ISI, IST and actually going out and working on stuff, turning wrenches, etcetera, as my colleague. J.D. Wilcox used to like to say.

The other thing that we wanted to make sure of is that if we want to have structure systems and components that are in the D-RAP scope treated in the manner in which they deserve during the operations phase then not only do they need to be within the maintenance rule scope, but they need to be captured in the high safety significance category within the maintenance rule scope. Then they're going to be monitored typically at the system or train level. In some cases, depending on the situation, they might even be monitored at a component level, but typically, it's a system or train level.

The other thing is they'll be looking at both reliability and availability and some condition monitoring as well. So they get the full treatment if they're in the high safety significant bin in the maintenance rule program.

Let's go. I identified in looking at the DCD, I identified, it looks like five RAIs and some supplements. They weren't super-significant technical issues, but they were things that needed to be complete to have the whole package properly put together. They dealt with references. They dealt with COL action items, of course, would probably be the most significant technical part of it. And one other item and just some discussion back and forth for GE is that of adapting the D-RAP scope for operations phase.

What we're talking about there is that we anticipate there may be additions and subtractions from the original list. As you learn more about the plant, as the plant actually gets built, as components are selected, things which people thought might be risk-significant may not be so risk-significant and vice versa. We may identify other structure systems and components that need to get added to the list. So all this is is just making sure that there's a process to carefully control what gets added -- well, added is probably not as important as what somebody might want to subtract from the list to ensure that when the plant is ready to load fuel, that the list is stabilized and everybody knows what's risk significant and what isn't risk significant.

Now even as the plant operates over the years, and the PRA is maintained and updated, you'll learn more about things because you'll learn more about failure rates of equipment that you may not have a lot of industry operating experience in. And so some default failure rates, based on similar types of components might have been chosen. Later on, you'll find out that they are either more reliable in this particular application or less reliable.

The RAIs and supplements have all been resolved satisfactorily, the ones that I'm dealing with here and they'll be closed, pending confirmation and when I take a look at revision four, to make sure that revision four looks like what we've agreed upon it's supposed to look like based on our comments of revision three. And I might add that in their responses to the RAIs, in addition to stating how each RAI would be resolved, GE also provided us with a draft section of revision four to show us what it would really look like. And so really, those are just confirmatory notes.

So now I'm going to turn it back over to

Rich for the first two COL action items to talk about them in more detail.

MR. McINTYRE: Yes, and wrapping up the COL action items and these items are all identified in the staff safety evaluation report, so these should all, they're all documented in a pretty straight forward. The two that we came out of, the QA program review is 17.2-1 and that states that QA activities associated with the construction and operations, including the site specific design activities are the responsibility of the COL applicant.

And the second one states that the overall project quality assurance program document that QAPD or the QA topical is also the COL applicant's responsibility and that's very clear within the safety evaluation report.

MR. ALEXANDER: Okay, the COL action items that are related to reliability assurance, first of all, the first one was to establish PRA importance measures, expert panel, other methods for site-specific D-RAP scope. The PRA importance measures that are suggested for use to determine what's high safety significant in current issues, in the current revision that's endorsed revision two of NUMARC 93-01, we recognize that because of the operating characteristics of some of the newer designs, some of those PRA important measures may not be as meaningful as they were. The example I like to use is that if the core damage frequency is in the order of 10^{-8} then a raw of two may not -- doesn't mean too much really. Two hundred might, but two doesn't mean so much any more. That's just an example of where some adjustments are going to have to be made and of course, this is what GE is putting their expert panel together to do, to do just that.

MEMBER POWERS: Is it the wrong PRA to use?

MR. ALEXANDER: Is it the wrong PRA to use? No, sir. Not at all. Their PRA will be whatever it comes out to be, but we already know that some of the baseline core damage frequencies are going to be, in general, somewhat lower and so the specific numerical numbers that are suggested in NUMARC 93-01 may not be appropriate for another plant.

MEMBER POWERS: I understand your point there. It strikes me that the operational event PRA might well predict 10^{-8}. I doubt that there are very many sites in the United States, at least a couple perhaps, but not many, where I can get a seismic PRA to come down to 10^{-8}. I think I'm stuck. It's not 10^{-5}.

MR. ALEXANDER: Absolutely. Because, of course, you've got common mode failures and so on going on. Absolutely. I wouldn't attach too much significance to the 10^{-8} figure. That was merely as an example.

The notion that with some of the more passive designs, the CDFs, they generally tend to be lower. I threw that out as simply an example for a number to give you an idea of how the current --

MEMBER POWERS: I understand the point.

MR. ALEXANDER: And understand the point that because of other things such a seismic and common mode failure happenings that would be similar to that environmental qualification, perhaps, situations that yes, it could be. It could be higher than that.

MEMBER POWERS: Do we have a feeling for what the shutdown risks are?

MR. ALEXANDER: I don't personally know. I would probably defer to GE and their experts on their own PRA to come up with that one.

MEMBER POWERS: I don't know off-hand know how to do that, shutdown PRA.

MR. ALEXANDER: It's a, well, of course we struggle with that in the operating fleet as well.

MEMBER POWERS: We do indeed.

MR. ALEXANDER: So a lot of times we have to rely on shutdown rather than on quantitative PRA insights. We use defense-in-depth and try to preserve key safety functions and that's the approach that's being used. Bless you.

MEMBER POWERS: An ardent structuralist after my own heart. But it also puts a burden on the role of the expert panels in these things.

MR. ALEXANDER: Which is, of course, another reasons why they are going to need to have quite a broad spectrum of disciplines involved in the expert panel.

MEMBER POWERS: We're going to get along just fine. I can tell that right now.

(Laughter.)

MR. ALEXANDER: Thank you, sir.

MEMBER SIEBER: One of the experts that you're going to need is an operations expert. Since you never built the plant, you aren't going to come up with one of those. So I wonder how you deal with that.

MR. ALEXANDER: Well, of course what GE said and what we are expecting them to do in following what they're going to do on this is is they have some, correct me if I'm wrong, they have some folks in-house that they've hired in from industry who have operational experience with the current BWRs and they will, if necessary, go to their customer base to get more operational experience. Unless somebody comes up with a better idea than using the experience of people who know how to operate plants as they are now, hopefully we will at least get them started until they can get some operational experience with the plant.

MEMBER SIEBER: And this plant is quite a bit different than current plants.

MR. ALEXANDER: I understand.

MEMBER SIEBER: So there's a little bit of a stretch there. Of course, when we built the existing plants, we had no background.

MR. ALEXANDER: I think, yes, with no background at all we're in a lot better condition now as a nation in having this much experience with nuclear power in general so that hopefully people with operational experience in one kind of plant can perhaps be able to generalize that a little bit and adapt their thinking to the difference, to the different operating characteristics for a new plant. That's what we would expect GE to be looking at when they're coming up with their expert panel. Does that make sense to you guys?

MR. HINDS: This is David Hinds with GE-H. We have quite a number of very recent experienced plant operators who have joined our staff and you are correct. They operated previous design, boiling water reactors. But they're also involved in the design process in the Human Factors Engineering Process for the ESBWR itself as well. So they're developing quite a knowledge and expertise on the ESBWR in carrying forward their operational experience from the current fleet of operating boiling water reactors. We think that's the best operation experience that we can have. We also have current plant operators in our customer base that are participating in with the process.

MEMBER SIEBER: It would appear that it might be prudent to build a simulator right along with the design process in order to enhance the operational assessment ability. That's a commercial decision.

MR. HINDS: And we are working on design

of a simulator at this time and we use the actual simulation software in with part of our process. So that is an integral part of the design process as far as simulation of system inter-relations and with an end goal of building a physical simulator.

MEMBER SIEBER: I see that as a commercial method as opposed to a regulatory method.

MR. MILLER: Rich Miller from GE-H. Also, these SROs from the past are involved in our assisted functional requirements analysis, all our task analysis activities. They are also integrated with our simulated engineering assistance tool where we do our design in that tool for controls and are deeply involved in that also.

MR. ALEXANDER: The next COL action item we had was 17.4-2, which is to integrate the objectives of the reliability assurance program in the operations phase into quality assurance. And in specific to make sure that we're addressing the non-safety related but risk-significant SSC failures that were discussed in SECY 95-132, item E. If anybody wants to know what that is, I have it here but it runs a little bit long to explain it.

17.4-3, tasks to maintain reliability.

What we're talking about here, again, these are just paraphrasing summary statements of the COL action items. But the idea is that an important part as I mentioned before of maintaining reliability is actually just to do maintenance and testing on components to determine their performance and condition and to perform maintenance tasks, physical maintenance tasks that keep them performing to an acceptable level. Change the oil, change the filters, all the usual things that you have to do with equipment to keep it running.

Of course, the maintenance rule program then is designed to monitor the effectiveness of maintenance and it is to some people's dismay a little bit different because in the maintenance rule program, we step back and take a look at performance or condition, mostly by reliability and availability for performance and condition monitoring and use that as a measure of how good the maintenance is, particularly looking at failures or degraded conditions that may be related to maintenance practices.

And so it's really to monitor the effectiveness of the maintenance and our inspection process on a routine basis for operating plants will then start to look in more detail the maintenance process on a for-cause basis. This is not as proactive as you might expect. It's more reactive. It's performance-based. And it was intended to be that way.

So -- but we do have a process and it's even prescribed in the inspection procedures where if there's degraded condition identified and it may be attributable to maintenance or maintenance might be implicated, then the inspectors are empowered to go out and actually take a look at that in more detail to find out what might be wrong with it.

The design reliability assurance program structure systems components, of course, must be in the high safety-significant category. That was another COL action item. And all of these things to support what we talked about earlier. And finally, we wanted to make sure that there's a reliability database basically industry operating experience which incorporates also plant operating experience with the equipment as well as general industry operating experience, surveillance testing and a maintenance plan.

Any questions on the COL action items that we have established so far?

MEMBER MAYNARD: Back to something, the generic ones, the first two that you brought up.

MR. McINTYRE: Yes, sir.

MEMBER MAYNARD: Those look like they would be COL action plans for any design implementation. I'm not sure -- have we written something into the rule that forces us to put an action item when really it is something that's not for the design certification phase?

MR. McINTYRE: You are correct. Those are items that would be applicable to any certified design. You're right. And any applicant is going to have those responsibilities.

CHAIR CORRADINI: So just to follow up, so that if we went back to AP1000 or whatever, those appear also.

MR. McINTYRE: They should.

CHAIR CORRADINI: My way of thinking of that is let's back check and see.

MR. McINTYRE: One form or another.

MEMBER MAYNARD: Where I'm really going is, is there a need -- do we have to document something like this for every operation or do we change the rule or change our requirements to where it's clear that this is a COL application item and not something that we have to spend time with on the design certification?

MR. TALBOT: Just to interrupt one second. I'm Frank Talbot of the staff. I was the lead technical reviewer for the AP1000 SER write up and D-RAP COL action items are more or less almost identical to the ones we have here for the ESBR.

MR. McINTYRE: That leads to your question even further.

MS. CUBBAGE: This is Amy Cubbage, NRO staff. I would just like to make an overall comment on COL action items. They're not necessarily comprehensive and they don't -- the absence of a COL action item does not relieve a COL applicant of the obligations to meet all regulations that they would be responsible for meeting. So in some aspects it's a guide to help ensure that the COL applicant has a complete application, but we also have Reg. Guide 1.206 which is a guidance for the content of a COL application and a COL applicant would have to meet all applicable regulations.

MEMBER MAYNARD: And I don't want to

belabor this, but my only point is it looks like we have something here and we could toss everything into here about what the licensee has to do in the operating phase and stuff, but this is something that doesn't appear to me to be something necessary to be part of the design certification and --

MS. CUBBAGE: Arguably, you could be correct there, that we wouldn't necessarily have to have these COL action items to ensure that the COL applicants would fulfill their obligations.

MEMBER MAYNARD: If there's a need to have a requirement, it should be in the COL requirements as opposed to the design -- it's fine. I'm just -- it has nothing to do with the ESBWR or this --

MS. CUBBAGE: Until the issuance of Reg. Guide 1.206 which provided guidance for the applications, there really wasn't a clear dividing line between the scope of a design certification and a COL application.

MEMBER MAYNARD: Okay.

CHAIR CORRADINI: Other questions?

MEMBER STETKAR: I'd like to go back to something Dana raised regarding shutdown risk and the process that will be used to identify SSCs which conceivably are important to risk during all modes of operation.

Contrary to what Dana implied, there is extensive experience with doing shutdown risk assessment. It happens to be outside of the U.S.

MEMBER POWERS: I think I said I didn't know of it.

(Laughter.)

MEMBER STETKAR: I stand corrected. The results from several shutdown risk assessments that have been performed for a variety of different plant designs have shown a relatively large contribution to overall plant risk from events that occur during plant shutdown, anywhere from 20 to 80 percent depending on the study, depending on the plant and so forth.

So it's not, the studies that have been done have concluded that this is not necessarily an insignificant issue. The reason that I raise this question is that given the fact that there is not a comprehensive shutdown risk assessment for this design, something I heard yesterday raised a bit of a flag and that is that the design is not qualified for 72 hours decay heat removal capacity, operator hands-off, no AC power during shutdown modes. I think that statement was made yesterday.

CHAIR CORRADINI: You ought to check that statement.

MEMBER STETKAR: Is that correct?

MR. WACKOWIAK: That statement is generally correct. There's not a requirement for it. Most of the modes when you go through shutdown, it is true that that is the case. But there are some configurations where that is not, where active systems are needed before 72 hours. So in the tech specs, they configure it that way. And just to correct one other thing, we do have a full shutdown risk assessment in Rev 2. We had a risk assessment with some gaps in the previous round, but we've closed those gaps. So we've done it based on a standard refueling outage.

So the work going on in the outage, somewhat determines how the risk goes. So we've done a refueling average and we've covered events, like internal events and fires and floods and weather events during shutdown. So that's there. I think the characterization is right that the shutdown risk is not insignificant, at least by the way we are calculating it now.

MEMBER STETKAR: My only point was during the, when the expert panel is convened to identify the SSCs, I would hope that that expert panel will have experience both in shutdown operations, operations, maintenance activities during shutdown, and have a sensitivity to the implications in the risk assessment of that. You know, without trying to influence anything, it may be possible that additional safety significant equipment could be identified specifically through the shutdown part of the PRA and the expert panel evaluation process that might not at all be evident from the full power PRA, where most of the emphasis has been placed.

I'm hoping that part of this interaction --

CHAIR CORRADINI: Can I turn John's comment into a question? So give me an example, I mean since this is not my area of expertise, but I'm just trying to understand. Give me an example in the shutdown mode an SSC that you might identify that wouldn't be identified in the power mode?

MR. WACKOWIAK: The most obvious example is the lower drywell hatch. That's a very important component in the shutdown PRA.

CHAIR CORRADINI: And that's because of maintenance to the CRDMs?

MR. WACKOWIAK: It might be open because of maintenance to the CRDMs and when it is opened, it introduces a failure mode that does not exist at other times.

MEMBER STETKAR: Yes.

CHAIR CORRADINI: Is there, so, let me ask the question one step further. Is there an active system that might be identified? To get back to your original comment, which is I can't go the full 72 hours without some active system. Is there an active system that you would want to watch, maintain, from a shutdown character versus a power character.

MR. WACKOWIAK: From -- there are some things on the preliminary list that we've talked about earlier that show up as significant in fire type events. We call that the preliminary list because where we finish the actual, well, and then when we do the actual configuration of the plant and do the walk-downs and we're at a point where we can do some fire modeling, it may turn out that these SCCs are less significant than they are with the bounding fire PRAs.

So the way we're handling it now is we'll present that information to the expert panel and discuss the limitations of the fire PRA and why, if at all, we would think that something is either conservative or if we find anything that's not conservative, I think we've addressed all of those in our sensitivities. But you know, we would discuss those things with the panel and try to determine is this something that's going to remain significant when we do the fire modeling and get a look at fire growth and propagation and actuations.

So the initial list to circle back and answer your question, the initial list contains some of those components. Off the top of my head, I don't want to pick the wrong ones --

CHAIR CORRADINI: That's okay. But you probably relate it to fire risk?

MR. WACKOWIAK: For the most part. The fire risk in shutdown is where we see the most interaction with active components. The other-than-fire risk is mostly associated with drain-down events of the vessel caused by pipe breaks during shutdown, and that's where the drywell hatch comes into play. The plant, without the common mode spatial interactions introduced by fires, the plant is fairly robust during shutdown.

MEMBER MAYNARD: I think one of the things that is important for these reviews is as much as identifying any additional safety systems components is where it might be beneficial to have some more defense-in-depth, which is what we typically use heavily during shutdown situations since sometimes you're done to one train. What other defense-in-depth do you need? Not necessarily safety related backup systems stuff, but there's a lot of things that could be done in shutdown that couldn't be done in power operations from a defense-in-depth standpoint.

MR. ALEXANDER: This is why I commented earlier, when I answered the question about that is that our approach in shutdown in general is defense-in-depth, you know, redundancy and diversity and concentrating on preserving key safety functions. But we do, of course, have a fair amount of experience in the industry today, even in this country, in the more sophisticated PRAs and risk assessment tools that are in use.

An example comes to mind. I believe that the San Onofre Plant uses something, without mentioning any brand names, it can do everything including the kitchen sink. In other words, it will actually do configuration risk assessment for all modes of plant operation and transitions between modes. So if you have a very sophisticated model and risk assessment tool, then you can do shutdown. It's just a bit of a challenge.

MEMBER POWERS: My experience, when you use these tools that you talk about, and my experience even with doing shutdown PRAs that other people know that I don't, is that they are pretty good stabs at the problem for planned shutdowns. It's the unplanned ones that will be the ones that bite us. Stuff happens.

(Laughter.)

MR. ALEXANDER: The only good news there is that even with the unplanned shutdowns, the risk is driven by configuration and that's going to be whatever it happens to be depending on what breaks. And so they can still tend to respond to that even if it is an unplanned situation.

MEMBER POWERS: We better or we don't build the plant.

MR. ALEXANDER: And in fact, in terms of risk assessment, we have guidelines in place already that are used that when you have emergent conditions, the ground rules are that the plant will update the existing maintenance risk assessment as soon as possible on an not-to-interfere basis with immediate plant stabilization restoration.

And in fact, if they fix the problem before they get a chance, let's say in the back-shift, and they don't have a lot of PRA practitioners hanging around -- if they don't have a tool that's easy for operators to use --

MEMBER POWERS: Many of us would like to move the practitioners to that ship.

MR. ALEXANDER: That all happens on the back-shift. And what happens is if they get the plant restored and the situation is now cleared, they don't even have to do anything further, but there is an expectation that to the extent practicable and if there's people available that risk assessments will be updated as things happen.

DR. KRESS: That's all well and good, but the identification of SSCs, for example, has to look at the lifetime of a plant and it's very shutdown modes planned or unplanned, those risk tools you're talking about are very good; the plant shutdowns and to give you an instantaneous reading of what your current status is. They're useless for the lifetime estimation of the contribution-to-risk during shutdown. I don't know how to do that, frankly. I don't know if PRA specialists could tell me how to do this.

CHAIR CORRADINI: Tom, I don't think I understand. So can I just -- I don't think I understand your --

DR. KRESS: You're looking at the probability of having a core damage frequency -- for the whole lifetime of the plant, due to various unknown, unplanned, shutdown configurations that vary with time and space and plant, I don't know how to do that, frankly. And I don't know if a PRA specialist could tell me how to do that or not.

CHAIR CORRADINI: Versus planning and shutdown for refueling and plant operations.

DR. KRESS: Planning is wonderful with the risk tools they have. It's great and for the maintenance issues, it's great. I just don't know how you use those to define SSCs. And that's what we're discussing. And so I wish somebody would tell me how.

MR. ALEXANDER: There's one approach

that's used already to come up with that and that is, for example -- we're a little off of QA here, but for example --

CHAIR CORRADINI: Not that we tried to.

(Laughter.)

MR. ALEXANDER: One approach that kind of, I think might get a little bit toward what you're asking about is an approach that's taken with the risk-assessment style, if you will, that's used by South Texas. What they've done is they've gone in and pre-analyzed something on the order of 10,000 different possible configurations.

DR. KRESS: Already stored those on their machines.

MR. ALEXANDER: That's right, and so with those -- and this is not based on operating experience. This was based on what could happen --

DR. KRESS: But you have to have a probability of having those configurations.

MR. ALEXANDER: I understand, but --

DR. KRESS: For the amount of time you're in those configurations.

MR. ALEXANDER: That's correct.

DR. KRESS: Those things you don't have.

MR. ALEXANDER: What I'm saying is is that they have looked at probable and improbable configurations. They came up with as many configurations as they could possibly think of.

DR. KRESS: This is great for planning maintenance, on-line estimation of what your status is. I still don't think you can use those for estimating --

MR. ALEXANDER: While we're giving it, their approach and the way I understand it was to help identify risky configurations and after you've identified the risky configurations that are the highest risk among those 10,000, and you start to see a certain structure system, components showing up time after time, one of the -- the 90 percent cutset method is one of the screening tools that's used for those. So when the frammitz shows up all the time as being high risk, then even without a lot of operating experience, you can say that this one is going to be a high-risk item for this plant. I think that's the approach that they're taking.

DR. KRESS: That would be right.

CHAIR CORRADINI: Can we take us back to the QA land and make sure that we're okay in Chapter

17? I know you're enjoying this --

MR. ALEXANDER: I'm starting to get in over my head anyway.

(Laughter.)

CHAIR CORRADINI: I thought that we would -- not that we would stress this young man's abilities, but we're kind of a bit off topic and not everybody at the front table can be appropriately quizzed on this. So anything back on Chapter 17 before we --

MEMBER MAYNARD: There is somebody behind you, Mike.

MR. HAMZEHE: This is Jose Hamzehe, the PRA Branch Chief for the New Reactor Office. And I just wanted to echo what Mike was saying. We have the PRA branch that is working very closely with GE and we are reviewing very closely their risk assessments including the shutdown risk. And as it relates to 17.4, so we are going to assure that the risk significant SSC has a reasonable presentation of all the SSCs during full power operations, shutdown operations, external events, internal events to the extent possible at the design stage. And we will make the presentation at the later time, we can answer all these questions more eloquently.

CHAIR CORRADINI: Great. John and Tom will welcome that, I'm sure.

MR. ALEXANDER: Could I actually add one more thing on another area? Since there may have been a little bit of misunderstanding about commercial grade dedication. In commercial grade dedication,. having had some experience as a recovering vendor inspector, I know a little bit about commercial grade dedication and the way that the mode seems to fall out as envisioned with the operating fleet is largely with replacement items as was stated here.

But it turns out that now that the process of commercial grade dedication has been refined to the point where it is a pretty rigorous process or can be if it is done right, sometimes even more so than just buying something from a vendor who claims that it was designed, excuse me, designed and manufactured under an Appendix B QA program. It provides, for example, the buyer with a lot more control over the details and so it's a process that is now being used by some licensees currently to buy new stuff.

The acquisition of the six diesel generator system by Diablo Canyon was done by commercial grade dedication. The oversight was by the licensee. So it's a process that is now another tool in the bag that can be used and what our expectation would be that that General Electric or any of the vendors are going to use it to the extent that they deem, if it turns out to be the best way to buy something, especially in a case where a component that really is the right one for the job may not be available as an Appendix B.

And so they will still be using some commercial grade dedication and we'll expect it to be, you know, a complete and rigorous commercial grade dedication process.

CHAIR CORRADINI: Other questions?

MEMBER MAYNARD: I just have one generic question. This was all done under an Appendix B program and stuff, but is there any movement towards any of the new QA standards, the ISO-9000 as opposed to Appendix B. Do you anticipate any applications coming in at a later date?

MR. McINTYRE: I wouldn't anticipate ISO-9000, but one of the things that opened code standardization looks like ASME is going to come out with a new edition of the NQA-1 standard in 2008 and

NRC staff has been part of that to try to bring the NQA-1 standard more in line to what it was in 1994, which was the current approved version.

So I would anticipate that probably down the line, the next volley of applications will probably be coming in to NQA-1 2008. I wouldn't envision ISO-9000, there would be a number of enhancements that you would have to make to make it comparable to Appendix B or NQA-1.

MR. ALEXANDER: I could add to that a little bit. And it also gets to the notion, you know, commercial type of quality assurance and quality control. There are some very important differences, obviously, between the ISO process and Appendix B. As far as I know, we're sticking to our guns in requiring it and we've seen some vendors who have augmented ISO-9000 programs in order to meet Appendix B.

MR. McINTYRE: We did issue a Commission paper in 2003 where we pretty much compared Appendix B ISO-9000 and NQA-1 and the conclusion we came up with, some suggestions on how you could implement an ISO-9000 program and the enhancements that would be required to be in compliance with Appendix B.

MR. ALEXANDER: In talking, mentioning one thing about commercial grade along those lines, as of 1995, commercial grade dedication was codified in 10 CFR Part 21, the important elements of it. And one of those important elements was that a commercial grade dedication process must be controlled by the applicable requirements of Appendix B, whoever is going to do the dedication has to have their own Appendix B program and control that process under that program.

CHAIR CORRADINI: Other questions?

Thank you very much. Concerning where we are, let's take a break now until 10 o'clock and then we'll start with Chapter 8, with GE-H's discussion of Chapter 8 at 10. All right? And staff is here to follow-on, and we'll go to lunch on Chapter 8. Thank you.

(Off the record.)

MR. LEWIS: My name is Don Lewis. I'm with Office of Regulatory Affairs. I'm going to give a presentation on ESBWR Chapter 8, Electrical Power. Our presenters today will be Rich Miller, on the end here; Ira Poppel, and John Stryhal.

Without further ado, I'd like to get started.

MR. POPPEL: My name is Ira Poppel. I work with GE-H. I do some electrical work and ECIS work. The two are tightly coupled together at the safety levels which we'll try and talk about a little bit today.

We're going to talk about the electrical one-line and reference the Chapter 8 sections in regulatory compliance off-site/on-site power and station blackout.

This is what we're going to do, so let's go to the first one.

This is the main ESBWR electrical one line. It's basically the medium-voltage systems. I'm not sure how familiar the ACRS is with the electrical systems, so how much detail, but basically we have four 13.8 kV power generation buses and we have two plant investment-protection buses at 6.9 kV.

The connected load of the ESBWR is between 120 and 140 megawatts electrical. That's how many -- if you added up all the loads on the electrical system. The operating loads are probably 60 or 70 megawatts, depending on the plant site, cooling towers, etcetera. So the electrical system is a very significant item in terms of design issues.

Although there are few actual loads on the power generation buses, they are, in fact, 70 or 80 percent of the total connected load.

CHAIR CORRADINI: Can you say that again? I didn't think I --

MR. POPPEL: In other words, like maybe five, six, seven loads per bus total number of loads, but the power they consume is 70 or 80 percent of the electrical power of the plant.

The power generation buses are so called because that's where the very big motors are that you allow the plant to make electricity: condensate, feedwater, circulating water system, etcetera, that have -- I shouldn't say no safety significance because Rich may look at me strange, but in other words their loss doesn't affect anything but power generation.

CHAIR CORRADINI: And since I'm really a bad electrical engineer, let me just say it as I've been reading it. So that the flow of power is back into -- not to the distribution, to the switchyard, but essentially it flows out and back into the plant via the --

MR. POPPEL: We'll talk about that in some detail.

CHAIR CORRADINI: Okay.

MR. POPPEL: There are a few things about the normal electrical system of the plant as opposed to safety that are different for the ESBWR and the new generation plants in general. If you look here, you see a box called the main generator breaker. I think only two or three plants in the United States, nuclear plants, have a generator breaker.

The reason for this, this is not the switchyard breaker. Out in the switchyard, which is a COL thing, will be that breakers that control the generator flow of power back out and what they're selling. But when the plant is off, the generator breaker is open. And the switchyard backfeeds power into the electrical system. When the plant is brought on line, it's synchronized around the generator breaker which closes and then we feed power out. The significance of this is that the operator for the vast majority of events does not have to operate the electrical system. These transformers are not start-up transformers. They are reserve transformers. And I'll talk about that significance too. But in other words, in normal operation, the electrical flow looks like this to all the buses and the operator doesn't have to manipulate anything in start-up or shutdown to cause that to happen or in accidents for that matter.

So any time you can relieve a mode of operation, it's good. And there's no timing issues associated with this. If he wants to go to this, he can, slowly, but in general, the main generator breaker is a URD requirement now and of course, we have it.

CHAIR CORRADINI: URD?

MR. POPPEL: Utilities Requirement Document.

CHAIR CORRADINI: Okay, sorry.

MR. POPPEL: It's also a very, very common feature in European plants because -- okay, next slide.

This delineates -- I'm sorry.

MEMBER SIEBER: Why is it a common feature in European plans?

MR. POPPEL: American electrical system designers are a very conservative lot.

CHAIR CORRADINI: And cheap, too?

(Laughter.)

MR. POPPEL: And also, as the generators get bigger, those breakers get very, very dramatic in terms of size and capability, but it's a requirement in Europe and I think you're going to see now in all the plants. For example, the ABWR has a generator breaker also.

So it's a good feature for human factors.

MEMBER STETKAR: What's the operating medium of the breaker? Is it air operated, SF-6?

MR. POPPEL: It won't be SF-6 inside the plant. In our particular case, since we're on the other side of the transformer, it's basically a switchyard breaker, it's a high voltage breaker. So it's breaking, I'll put it in quotations, where low is like you know, like 3,000, 4,000 amps and it's operating, well, in most plants at 345 or 500 kV.

MEMBER SIEBER: But that won't be inside the building?

MR. POPPEL: In the ABWRs, it was and it can be, but if it's on a low-voltage side, the currents we're talking about are like 50,000 amps and 20,000 volts. So it just depends what's available, but the function is always the same, the function being that the switchyard normally backfeeds into the plant and the operator does not have to manipulate the electrical system in order to do start-up iterations or shutdown or normal operation.

MEMBER MAYNARD: And that's a single breaker?

MR. POPPEL: Yes.

MEMBER MAYNARD: Yes.

MR. POPPEL: It has in our particular case and almost everybody's case a triple trip coils and triple electrical system protection, protective relaying, you may know the phrase.

This is just a simple indication of where the switchyard is and where we are in terms of plant design. So this is the stuff that we do and sort of this is the COL stuff. That's their switchyard and their arrangements. Although, of course, we impose requirements on them. Next.

Okay. In the, despite the fact that we're a new and different plant, we do meet all the current regulatory requirements for electrical systems. The primary one of which is we have all the power from the outside world or from the grid is termed "preferred power", flowing into the plant. We have like everybody else does, a normal preferred power supply and an alternate preferred power supply. I want to talk about the normal one, which is pretty much as

I've just described. It flows in from what is called the unit auxiliary transformers and then to the power generation buses and to the plant investment protection buses. That feed, if you will, is enough to operate everything in the plant, including the balance of plant equipment on the power generation buses.

Yesterday you heard David Hinds say island mode of operation, 100 percent load reject, etcetera. This is a combination of features that isn't a requirement, but we do have it. And basically if the plant is operating normally, meaning this generator breaker is closed and the generator is on and the reactors have power, and the switchyard breaker is open, which is indicative of a problem on the grid, in general, we cannot design our plants, you know, we can't make the grid reliable by anything we do in a design to this plant. We live with the grid, and as you've seen in several recent blackouts, most plant's response to the grid is to scram and go on their diesels which is safe, but always an interesting iteration.

What happens in our case is the switchyard breaker is open. So the main generator no longer has a path for 1600 megawatts. So in our case, the bypass valve is open. We have 110 percent steam dump capability. So the bypass valve is open in approximately two-tenths of a second and the turbine control valves slam shut because of course there is no longer any place for 1600 megawatts to go. And then they reopen again to support house load.

So the net result is we have another, if you will, normal preferred power plant independent of the grid from the main generator. The island mode refers to the turbine design capability of being able to operate at reduced load with good voltage regulation and good speed control, which is another way of saying 60 Hertz, and we don't want to end up operating at 40 Hertz with all of our motors.

So in fact, I don't want to say that we're immune from the grid, but most of the events that have taken most of the U.S. plants down will not take us down. And again, the operator will have to do nothing. The whole event is over in something like two-tenths of a second, so the operator doesn't realign, react or whatever. He ends up with an automatic power reduction in the reactor. The generator is sitting there on house loads, which in this case will be about three percent of its capability and everything operating normally, feedwater system, reactor pressure. All is still normal.

CHAIR CORRADINI: So let me make sure I understand. So the transient you discussed, the island mode takes, I assume you guys have simulated this, takes what in terms of a time scale?

MR. POPPEL: About two-tenths of a second.

CHAIR CORRADINI: But not to go from 100 percent? Let me just ask a different way. I'm at 100 percent power and the reactor comes to what percent power in what time?

MR. POPPEL: Oh, I'm sorry. The existing, so the bypass valves and the existence of the control valves, the control valves react to close.

CHAIR CORRADINI: Right.

MR. POPPEL: Because their load went away.

CHAIR CORRADINI: Right. So the bypass --

MR. POPPEL: So as far as the reactor is concerned, instantaneously post event, it's still at 100 percent power. It didn't know anything happened. One hundred percent steam flow is still coming out, except that it is going to the bypass instead of the turbine, okay? So there is no pressure blivel. There is no level blivel. It's all steady-state.

Now at that time, we initiate an automatic power reduction because we don't want to beat the condenser to death by dumping in that steam. So the reactor will come down. Our target pattern is something like 40 to 60 percent, but well within the generator, the condenser's steady-state capability, and we anticipate that happening over a time scale of minutes.

CHAIR CORRADINI: Okay.

MR. POPPEL: But again, the operator doesn't have to do anything.

CHAIR CORRADINI: But less than a few seconds, you do the switch over of the bypass valves and the turbine stop valve.

MR. POPPEL: Less than one second. This sounds a little scarier than it is, but for example, the European BWRs and the ones that we have done, in fact have this capability and it is a start-up test requirement.

MEMBER ABDEL-KHALIK: How long do the condenser dumps last?

MR. POPPEL: Well, until the power comes

down.

MEMBER ABDEL-KHALIK: No, I mean as far as the number of these transients. Physically, how long do they?

MR. POPPEL: Well, I don't know what you mean. Basically, this happens not on any internal events of the reactor. It is external grid events. That's the only reason this event would be triggered because the grid went away.

CHAIR CORRADINI: I think he is asking how many times you can do this --

MEMBER BLEY: Before you damage the condenser.

MR. POPPEL: No, I'm sorry. The condenser thermal heat removal design is barely affected by this. What is affected --

MEMBER MAYNARD: This is not a new technology or a new item. Existing plants have this. They don't all have 100 percent bypass capability.

MR. McINTYRE: Most plants have 30 percent. We have 110 percent.

MR. POPPEL: PWRs dump steam to the atmosphere. It's a little awkward with us. We have to dump it into the condenser, but there's more bypass valves. We have 12 and the condenser has spargers in it that distribute the steam so it is designed for this.

MEMBER BLEY: What are the critical control system points that could interrupt this, like over speed or something on that before this two-tenths of a second?

MR. POPPEL: Well, remember --

MEMBER BLEY: Well, when it goes wrong, when you end up tripping, what tends to do it?

MR. POPPEL: Okay, here is exactly what happens. Normally the reactor would scram on a fast closure of the control valves or the stop valves. This would be a control valve fast closure. The turbine, the actual circuit is called the power load and balance relay. The turbine senses that is operating at a higher torque than the electricity that it is putting out. The response is to slam shut the control valves, okay?

The turbine will still, nevertheless, try to overspeed as a result. But of course, none of the turbine protections is gone. All the overspeed protection is there and the closure of the control valves itself prevents an overspeed. But we will go slightly higher in frequency, which of course we're designed for.

MEMBER SIEBER: How much?

MS. BERRIOS: It depends on the turbine design and its inertia. We don't know yet. But the plant is designed for like I think plus or minus five percent in frequency, 63 hertz to 57 hertz, and the turbine control system. I mean, this also sounds scary, but remember the turbine has a monstrous amount of inertia. So it is not accelerating very fast. The speed peak is probably 8 to 12 seconds after the event, not while it is happening.

So what happens is in the controlled system, which is what you asked, the reactor protection system would normally scram on this. What happens is we introduce a time-delay, nominally a tenth of a second. In the turbine control valve and stop valve scram. In the first tenth of a second, the bypass valves have to open and they are designed to. The reactor protection system interrogates the bypass valve position. If they are open, the scram remains bypass. If they are not, it scrams.

MEMBER SIEBER: Do you have governor valves and throttle valves or trip valves, right?

MR. POPPEL: Yes, right. But the turbine is not tripped.

MEMBER SIEBER: The run-back occurs when the governor valves go closed. Its trip valves always stay open.

MR. POPPEL: Yes, we need the turbine to be untripped for this event because after everything settles out, we want to make electricity for us. And so, and incidently in what I just said about bypassing the stop and control valve position, we have not bypassed the flux and pressure. So for example, if the whole scheme fails, bypass don't open, then of course we'll scram on pressure very, very shortly.

But again, the operating won't even be able to put down his coffee and get out of his chair by the time this event happens.

MEMBER SIEBER: He'll hear it.

MR. POPPEL: Yes. We'll have appropriately human-factored engineered alarms to indicate it to the operator.

MEMBER POWERS: In other words, we will have had spilled his coffee.

(Laughter.)

MR. POPPEL: You know, one of the reasons for this is we want a very highly reliable electrical system. It's not often thought about, but for example the equipment on the power generation buses by itself, assuming a successful scram, can shut down the plant. In other words, if we have the circ water pumps, the main condenser, and the bypass valves, we can remove all heat we want. And since this is in a vacuum, we can bring it down below boiling and we have a feedwater system where each pump is capable of 35 percent of rated steam flow.

That's needed for, we have four pumps. Three are normally online and 45 percent, I'm sorry. Which obviously is any one pump is so far above the normal decay heat load steaming rate that just one feedpump and one circ water pump alone will do it. So in other words, even if nothing else worked in the plant, assuming that you scrammed, you can shut down on one of these buses or, if you will, two of these buses and one transformer.

So, you know, it's not credited much but in the real world, most of the time the grid is there and in the real world, most of the time this equipment is there and in the real world the ESBWR has another path to success in terms of shutting it down. Next slide.

MEMBER STETKAR: I know, you are the electrical guy, but since we're talking about the turbine controls, does GE have any actual real-world operating experience with this type of turbine control system installed in a plant that's undergone a few transients?

MR. POPPEL: Well, some of the very, very early BWRS, I believe Millstone was one of them. I'm not exact --

MEMBER STETKAR: Is this the same control system though?

MR. POPPEL: Well, no. Now we've gone from mechanical hydraulic to triply redundant electrical hydraulic control systems. If anything, they've gotten better.

MEMBER SIEBER: Well, hydraulic pressure is very high now compared to what it used to be.

MR. POPPEL: Yes.

MEMBER SIEBER: But even the shipping port plant go back to house load and that's 45 years ago.

MR. POPPEL: But I mean, they're not doing anything special for us. Most of it is in the generator voltage regulator on the turbine speed control. Because of course, they have an intense interest in making sure, as you do, in making sure the turbine doesn't overspeed for other reasons, like disassembling itself. Next slide.

The yellow indicates our alternate preferred power path. Okay? As you can see, it's just another way, separate path from the switchyard of getting electricity to the same busses that the normal path did. Now even though the normal and alternate generally refer to getting power to the safety buses, in fact these transformers are sized like the unit transformers to supply the power generation loads, the PIP loads, and our safety loads.

So in other words, it is a complete alternate redundant path. So to the extent that you want to say it's nice to be able to shut down the plant with the power generation buses, we can do it in two ways. Okay? And we can do it without the grid with our island capability, okay? So another thing, I don't want to belabor too much the power generation buses, but our feedwater pumps are motor-operated. We do not care if the reactor is isolated in terms of getting the water into the reactor. We are not steam-driven turbine. They are adjustable speed drive. The motor speed is changed in response to reactor level. But the size of these pumps is what drives the size of the electrical system. They are enormous and one of the reasons they are enormous is because that chimney that David told you about is very sensitive in terms of void collapse.

So in other words, since level is very, very sensitive to pressure in the ESBWR, and one of the ways we overcome that is with brute force. We have a feedwater system with 135 percent capability instead of the older designs which were like 115. So normally our feedwater pumps are, if you will, running at about half power, but the electrical system is sized for, of course, their peak loads.

MEMBER SIEBER: So if you have four pumps and I presume they're worth, the motors are 10,000 horsepower apiece?

MR. POPPEL: About 13 to 15 thousand horse power each.

MEMBER ABDEL-KHALIK: Could you just explain to me how does oversizing the feed pumps sort of eliminate the sensitivity to sort of shrink and swell?

MR. POPPEL: You can't change the shrink

or swell, but you can change the response to it. In other words, if level drops, the old feedwater control system could pump in 115 percent flow. We can pump in 135 percent flow. And so therefore our level of responses are to a level dip are better.

MEMBER SIEBER: And your control system does not have to act as swiftly and as strongly.

MR. POPPEL: Okay, let's go to the next slide. Okay, this is perhaps the more interesting part to you guys. Plant investment protection is essentially 6.9 kV stuff and lower voltage, 480 volts. There are two of these buses, A and B, and they are more or less symmetrical and there's several things of interest on these buses. One is these are the buses that are backed by the diesel generators. We have two of them. They are very reliable. They are very large, about 14 to 17 megawatts, okay? And they are sized to run, I'm not sure the right -- well, certainly plant investment protection loads. But those things, when Rich yesterday drew his little graph, his little picture that showed the ESBWR is mainly passive, but in the center he had little active things which help out the PRA. These are the little active things on here.

So for example, where it says typical motor feeder, you will find things like the CRD pumps, the RWC USDC pump, the fuel and auxiliary cooling system pumps, plus a whole bunch of support equipment like HVAC, service water, etcetera, etcetera. Basically you can say with these two buses alone, and for safety just one bus, but these two buses alone you can maintain a normal plant environment. You can't make electricity for sale, but in other words everything is running. In other words, the control room, the lighting, you know, HVAC. All the support stuff is running and available to that and all these other things are power centers to the various buildings and stuff like that which do that. But the diesels are in fact sized to run all of that support equipment.

There's another interesting thing on here called the FMCRD power center. And you will see that they have a feed from the other PIP bus. It's important to GE that we have a hydraulics scram and an electric scram and the FMCRDs because they have motors support the motor scram, although you probably wouldn't call it a scram because it takes about one and a half minutes for the rods to go in. But they will go in on their motors if they don't go in hydraulically. There are two separate systems.

So therefore, the way to think about this is a power seeking bus. In other words, whichever bus has electricity backed up by the diesels or off-site power, the FMCRDs will get power. In fact, it is split into three load groups. Our FMCRDs motors are grouped into thirds and the design requirement is that two-thirds of the rods go in, in the absence of offsite power and a single-failure. And accordingly, two-thirds of those rods are chosen so that the core will shut down if just two-thirds of them go in.

So it's not safety, but it is important and it is very, very reliable given that each FMCRD, each one-third of the FMCRDs have two sources of power, either diesel or off-site, which of course is also two sources of power, reserve and unit transformers.

MEMBER SIEBER: I take it you can't get power to those from the battery?

MR. POPPEL: No. The peak loads of those is probably something like half a megawatt.

MEMBER SIEBER: Okay.

MR. POPPEL: I mean, normally of course

we're only moving a few rods at a time, but in this even, you know, we basically signal all rods in on their motors. And incidentally, that motor run-in happens with the hydraulic scram. Anytime you have the hydraulic scram, you get what is called by a scram follow and the motors are signalled to draw the rods in whatever the scram do.

CHAIR CORRADINI: So their drives follow the thing that is already past them, right?

MR. POPPEL: Yes. But if a scram hadn't happened, now Rich is a purest and will say of course the reason the rods didn't go in is because they were all stuck, which we can't fix. However, as long as the rods can physically move, we can physically move them with a hydraulic scram or a motor.

MEMBER ABDEL-KHALIK: Let me just go back to something you said. You're saying that the design requirement is that the reactor would be shutdown with only two-thirds of the rods at selected locations?

MR. POPPEL: Well, chosen locations.

MEMBER MAYNARD: And this is three, is what you're saying?

MR. POPPEL: Yes, it's two of the three groups.

MEMBER MAYNARD: The group stuck at any two won't give you the shutdown?

MEMBER ABDEL-KHALIK: Any two?

MR. POPPEL: Yes. This plant has 270, 269 control rods. And it is different than a PWR shutdown characteristic.

MEMBER ABDEL-KHALIK: Okay.

MR. POPPEL: The other and probably of most interest to this group is we have these isolation power centers and now we're starting to get into the safety systems. We have two isolation power centers, but before we go on, notice that each one can be fed from PIP A or PIP B. Normally, two are fed from one and two are fed from the other. But just like the FMCRDs, they have the capability of being fed from either diesel. Next slide.

MEMBER STETKAR: One question on the diesels because you're going to get into the lower voltage stuff here.

MR. POPPEL: Okay.

MEMBER STETKAR: I noticed in the design description that you have interlocks on the diesels so that if you, if the diesels are parallel during testing and you have let's say a LOCA, according to the design description, you open up the diesel output breaker. Is that a lockout on the diesel? Will the diesel come back after that?

MR. POPPEL: No, it's not a lockout.

MEMBER STETKAR: It's not a lockout? None of the testing interrupts or lockouts?

MR. POPPEL: Its logic, you know, lockouts is terminology meaning manual reset.

MEMBER STETKAR: Right.

MR. POPPEL: And so, I should also explain that we are not starting these diesels on a LOCA.

MEMBER STETKAR: I know. But if it is running during a test, there are three different conditions that I read that will indeed open up the diesel output breaker if something happens while the diesel is running in test. Without going into the details, there are three that I found.

The question I had was do those conditions lock the diesel out such that it must be reset before it will re-energize the bus if power is subsequently lost?

MR. POPPEL: That is correct and the reason is --

MEMBER STETKAR: Does it do it? It does

lock it out?

MR. POPPEL: Yes. It does require manual reset.

MEMBER STETKAR: That's enough. Beyond that, that tells me what I needed to know.

MR. POPPEL: One clear thing is it is hard to start a diesel slow. We're not trying to start these fast because in fact we have made a perfectly good station blackout case and safety case. We don't need the diesels to start it all, okay? So if that operator has to do something manual, it's not a big burden.

This is repeating what you saw earlier where you have the normal feed to what eventually will be the safety buses. We'll describe it. Next slide.

And the alternate preferred power feed. So this is basically to demonstrate to you guys that the safety buses will get power from either of the two off-site sources, satisfying a general design criteria.

MEMBER SIEBER: Now you have no tie-breakers or voltage chasing schemes, right?

MR. POPPEL: We have --

MEMBER SIEBER: If you lose the offsite

feed, you lose two divisions, right? Out of four.

MR. POPPEL: Let me explain that as we get into the safety. This is different than an active plant. Next one.

This demonstrates the diesel feed to the safety buses, okay? Nothing dramatic there. Next slide.

Did something change? Next slide. Okay, next one. Okay.

Now, we have four divisions, safety divisions, in the ESBWR and four completely separate electrical systems. These are the four isolation power centers. This is what takes the 6.9 kV bus voltage from offsite or from the diesels and brings it down to 480 volts. Technical terms are these are double-ended load centers and this is the feed from either PIP bus. Okay, so normally one is closed. They are interlocked. It is only one at a time is closed, so normally two are on A and two are on B. So in other words, 480 volts is here when either of the diesels are running or offsite powers, whenever any one diesel is running and whenever offsite power is available.

Now I want to show you where it goes, so next slide.

We keep emphasizing. This is the normal preferred feed to the safety 40 volt bus. Next. Okay.

Now this is what is actually happening in the ESBWR safety systems, which will more directly address your question.

First of all, the good news about ESBWR safety system, electrical systems, is that they're not very big. Although we haven't finished the design yet, we are talking about perhaps 30 to 50 kilowatts per division. In the context of what you guys are normally hearing about, like for the example, the ABWR has seven megawatt diesels. So that would like 7.05. So an active plant, the DCIS portion of the safety system is round-off error. In the ESBWR, that's all there is. Different change, okay?

And so that's also good news and bad news is because even though that's all there is, we still have to arrange for a good way to power it, which we'll talk about. Our good way to power it is each division, each of the four divisions has two inverters and it has two uninterruptable power supply buses which permeate that whole division. And all of our equipment in the division, all of the DCIS equipment has, if you will, two power supply feeds. So in other words, in the end, one half -- not one half -- say a NUMAC or SSL CESF, any of our boxes that are DCIS has a power feed from here and a power feed from here and will work off of either.

Okay? So one of the reasons we do that is because we're so into self diagnosis of the DCIS. Obviously, if the diagnostic is you have a power failure and you only have one power feed, you can't report it to anybody. So this way for all the events where you have single failures and there's not many failures, we basically can continue the self diagnostics and inform the operator what's going on inside the divisional DCIS.

If you look at these inverters, these are different than maybe what you're used to in that if you see the inverters are the dotted line or I should say the uninterruptable power supply is the dotted line and you'll see it has three incoming sources of power. One is the batteries which we'll certainly talk about. The other is an AC feed from that power center, 480 volts. That AC gets rectified and gated with a battery and is set up so that normally the inverted is running off of AC. The AC that might go away if the diesels went away. However, the -- so in other words, normally we're not drawing any power from our batteries, a little bit, but nothing for this.

And then the DC, from either the battery or from the rectified AC, goes into the inverter where AC is made. So in other words, the loss of the AC power feed from the diesel or from off-site power seamlessly gates to the battery. There's no switch, there's no manual, there's nothing. It just -- as soon as this goes away the battery voltage is higher, feeds the inverter. The inverter doesn't know anything happened. It just continues to make AC.

Now of course, an inverter itself can fail. And so we have, it may be hard to read, a static transfer switch. This is the third feed going into the inverter. A static transfer switch is a switch that throws within an AC cycle. So a sine wave, I'm talking about. So in other words, the inverter is kept synchronized to this and if the inverter loses its output, this switch operates and seamlessly provides power to the loads. So in other words, we've got an inverter failure cover. We've got a DC failure cover and we've got an AC failure cover and we still supply power to these buses.

In several of those failures, we could not supply power to the bus if simultaneously we lost off-site power, but in most normal operation, we don't lose anything. The tech specs will govern what to do about inverter failures and of course, if you lose just one of them, the other one continues to chug away in the division.

So if you will, these are our safety systems. Everything is coming off of here. It's a little bit of lighting and a whole lot of DCIS. And we don't use the batteries for anything other than to run the inverters. We make our own DC sources in the DCIS to run our solenoids and to explode our squibs. There are reasons for that we can talk about, but not quite yet.

MEMBER SIEBER: I presume you use a minimum of electrical motor-operated valve?

MR. POPPEL: We don't have any motor-operated valves. One of the things that happened early in the design was they were all scrubbed and now they're pneumatic and solenoid operated or they're explosive. So -- explosive sounds bad, but -- and basically all of our safety loads may be found in the control building and the reactor building which is why you see these buses on each division.

Next slide.

MEMBER STETKAR: Where are the UPSs physically located?

MR. POPPEL: They're physically located in the reactor building.

MEMBER STETKAR: In the corner rooms?

MR. POPPEL: Yes.

MEMBER STETKAR: What used to be called corner rooms.

MR. POPPEL: For those who don't know, our reactor building is divided into quadrants with a division per quadrant. So a whole vertical slice quadrant of the reactor building is like Div. 1, Div. 2 and these inverters and the batteries are there.

Everything important to safety, of course, is located in an appropriate seismic Class 1 building.

MEMBER STETKAR: Are the pit buses in -- where are the pit buses?

MR. POPPEL: The pit buses -- well, they're all over the place --

MEMBER STETKAR: The 69 kV.

MR. POPPEL: The 6.9 kVs and the electric building.

MEMBER STETKAR: The electric building.

MR. POPPEL: Yes.

MEMBER STETKAR: Are the inverters in separate rooms out there or are they just out with the rest of the low voltage?

MR. POPPEL: The inverters are in a room with the battery chargers, with things that are associated with the power for the safety systems.

MEMBER STETKAR: Okay.

MEMBER MAYNARD: So the batteries have a separate battery charger. They're not just getting their charge from the --

MR. POPPEL: We'll demonstrate.

MEMBER MAYNARD: Okay.

MEMBER BLEY: One little question. I'm not familiar with the static transfer switch. What kind of device is that?

MR. POPPEL: From a black box point of view, imagine a box with power A, power B --

MEMBER BLEY: I think I got the black box point of view.

MR. POPPEL: It's basically, in the old days it was thyristors, now they're buzz, buzz words, they're still solid state transistor switches that can operate quite quickly and they have logic in them to say there's no power there, turn these on.

That's a fairly old technology, the difference being, of course, since it's in a safety system, it's a safety component. Okay.

Next.

Okay. I'll go through these quickly because it demonstrates what I just said. Here is the battery feeding the UPS, the safety buses. Next.

Now, the inverters are sure, uninterruptible power. What assures the 72 hours are the backers. They are the fuel tank for our diesels. And so even though I said the electrical system, the safety systems are very, very small, for example, a 50 kilowatt inverter, not counting inefficiencies, etcetera, operating at 250 volts, is like 200 amps. Two hundred amps for 72 hours is -- no, no. But in any case, it ends up like a battery capacity of like 6,000, 7,000 amp hours. The ones that you're traditionally used to seeing are like 2,000 amp hours, stuff like that.

So basically, we have to supply the entire electrical load of the safety systems for 72 hours from the batteries and the design is such, of course, the batteries will continuously lower their voltage as they discharge, so the inverters have to be appropriately designed to work down to that terminal voltage. As we'll get into later, trying to describe the battery load profile, as the voltage goes down, the current being drawn from the batteries will go up. Okay? Because the invertors, if you will, are operating at more or less constant power. We'll talk about that for a second, too.

But 6,000 amp hours at 250 volts, you know, a 12-volt car battery is 80 amp hours. You would need 20 of them to get to 250 volts and then you have to multiply them by three to get the amp hours. So the battery installation is enormous. It's one of the reasons where 250 volts instead of 125 because switch gear is basically current, not voltage. And so at some point you have a hard time being able to design an electrical system that has a huge amount of stored energy and if you have a fault in it, you know, the switch gear has to work to break the current and we can do that easier at 250 volts than at 125 volts.

The little bit of confusion comes about that per division are two batteries together are generally necessary to reach the 72 hours. So in other words, all of our DCIS, if you will, is operating at half power per feet. Okay? And so therefore the batteries are sized to supply half load for 72 hours.

There are also -- it's not exactly linear. They can supply full load for 36 hours. So even though our tech specs say we will lose the division if a battery goes out of service, we're declaring the division out of service although it has lost no capability whatsoever other than the ability to last 72 hours in a blackout. It will last 36 hours.

But nevertheless, to make it easy on our tech spec folks, if we lose two battery chargers, we have a standby per division or -- two battery chargers or one inverter for one battery within a division, we declare the division out of service, even though essentially everything in it will still be operational.

MEMBER SIEBER: So you actually have eight batteries. You have two per division?

MR. POPPEL: Yes.

MEMBER SIEBER: It's a lot of batteries.

MR. POPPEL: General arrangement folks

have made that comment.

(Laughter.)

MEMBER STETKAR: A question about the spare battery charger. I read somewhere and I can't honestly recall where, that the spare battery charger is used to put each battery on an equalized charge, however frequently that's done. And I read that it's done off-line. In other words, a battery is disconnected from the bus. Is that true?

MR. POPPEL: There's two directions that I can go. First of all, we may buy batteries that do not require equalizing chargers.

MEMBER STETKAR: Okay.

MR. POPPEL: And there's good reasons for that. The second is in an active plant, if you're testing the diesel, okay, as you would have to do periodically for surveillance, and you show that it's operational, and does its thing, when you're done with the test, the diesel is still okay. If you test our batteries while a plant is running and discharge them to show that they can operate for the full time, at the end of the test they're not okay. They're dead. And they have to be recharged.

And so if we had been designed as a

traditional N minus 1 plant, that would have meant that we would have been in an LCO, if we attempted to test online, the alternative being we'll only test during outages, but doing these tests during an outage where you're testing for batteries and series to show that they can all last the appropriate time would be an impact on the outage line.

So our customers wanted a design that allowed a whole division to be taken out of service with no tech spec LCO impact. That's where in the DCIS presentation you'll hear that this plant is designed to be N minus 2. Any two random divisions will satisfy the complete safety requirements of the plant.

Okay, and so one can be deliberately out of service. You can take your required single failure and you still have two divisions and they will still do all the functions.

Now this sounds unusual and again, it's a passive plant paradigm. If you have a large motor-driven injection pump, you can only connect it to one division. And therefore, it means something when that division is gone.

On the other hand, our squib valves can be connected to multiple divisions, because we can have a separate ignitor per division, so it's not a Div 1 squib value. It's a Div 1, 2, 3, 4 squib valve or in some cases a Div 1, 2, 3 and diverse protection system square valve. So that in other words, all of our valves will operate with any two divisions.

So it's not like you have to argue about well, our eight depressurization valves are enough or do you have to seven or do you have to have six. With two divisions out of service, all eight will operate assuming there's no mechanical failure in the DPV itself.

Now that's something you can only do with the passive plant design. For the other kinds of things, the solenoid valves, you can have a Div 1, Div 2, Div 3 solenoid on the valve to operate it.

So in other words, we've designed the system so that periodically during operation a division can be completely taken out of service, even though again it will be declared out of service because while you're playing with the battery, of course, the uninterruptable power supplies continue working off of the offsite feeds and continue still fully functional and so it's a strange out-of-service but nevertheless, it's out of service and you can test the batteries to complete discharge and recharge them. Take all the time you want and now have it an LCO impact.

MEMBER STETKAR: Let me ask you -- thank you. Let me ask you the question from a different direction then. A lot of plants have batteries that require periodic equalized charges, you bump up the voltage.

And you said you're not quite sure the specs on the batteries that you're going to buy yet, so you're not sure whether you're going to have batteries that are require equalizing charge. I understand the on-line deep discharge tests and all that kind of stuff.

I think the question I had is I tripped over the off-line equalizing charges for two concerns. One is that operating experience says that if you do that you tend to drop DC buses because operating switching errors occur when you charge batteries. That's just an observation. It does occur.

The second one is though is there a concern for the DCIS design, is it very sensitive to over-voltage conditions? In other words, the fact that you can't crank the DC voltage up to 267 volts or whatever you do it?

MR. POPPEL: Again, two directions. One is the DCIS never sees DC. It only sees the AC output from the invertors. So your real question is will the invertors care?

Okay? The answer is no, because we'll buy them that way.

The other comment is one of the advantages of having a stand-by battery charger is the electrical system is arranged so that the stand-by battery charger can do the equalizing charge while the DC electrical system is carried by the normal charger disconnected.

So in other words, you can run all the DC, but as I mentioned, we don't have any DC loads normally. The inverters run off of AC. So in actuality, you could probably completely disconnect it and it wouldn't matter, but we have the capability, in other words, our battery chargers are charger eliminators. They can act as a DC power supply as well as a battery charger.

MEMBER STETKAR: Reactor protection doesn't come off DC this plant either, direct DC?

MR. POPPEL: The reactor protection system, that part is up to the designers of the NUMAC, but in the past, only the backup scram came off of DC, not the normal scram, which is 120 volts AC.

Okay, I'm not sure what they'll do.

MEMBER STETKAR: Instrumentation stuff, not the -- okay.

MR. POPPEL: Okay. Next. Okay, we can go through this fast. This is basically the battery charger, charging -- the batteries, even though there's no particular load on them normally are, of course, left flow charging all the time, so that they're fully charged in normal operation at any time.

And this demonstrates that for the two batteries. Okay?

Next. I want to skip to one, and then go back to John. Can we go to the last slide? I want to do the -- address the open item thing a little bit.

Next, next, next.

(Pause.)

Now it is traditional in power plant design when you're specifying batteries that you -- -- somebody has to assume the load profile in the batteries, what they would do in their safety function. And write it down and then, of course, design the batteries and put in all the IEEE D rates, etcetera, etcetera.

And of course, we will do that. Okay? The problem is that as you may have gathered, essentially the complete battery load is the DCIS of the plant indirectly through the invertors. Okay, and then there's a little bit of lighting. And the DCIS load is, if you will, the logic and the solenoids and squibs. And so until we actually have the hardware of the logic, okay, in other words, how big is it, how much power does it take, etcetera, etcetera, we can't properly size the inverters and we can estimate which is what I did when I told you it would be probably between 30 and 50 kV. And as a result of not being able to properly size the invertors, we can't properly size the batteries or develop their load profile.

However, as John will tell you, we have every intent of determining what that equipment is, what the load profile is and supplying it. And it is not expected to be a problem because, in general, of the DCIS load, the vast majority of the load is constant power from the logic. Occasionally, we'll be picking up solenoids. It's a quarter of an amp at 125 volts. And occasionally, we'll be blowing squibs. However, that may be a bit power event, but it's not a big energy event in terms of batteries. Squib is blown. It's done. So it's not like you're turning on a big motor and running it for a while. It's an intermittent-type thing.

So we're not anticipating any problems with this, but, of course, we can't prove it to you until we're done.

MEMBER STETKAR: So if you go backwards to place where we first started talking about compliance, I'll let John Finish the -- talk about it. Okay, no, right there.

And flip to the next one.

I'm John Stryhal with GEH. I'm the lead electrical, and Ira was one of the prime designers carrying ABWR forward to this point. We have our regulatory compliance table, which is listed in Section 8.1.

CHAIRMAN CORRADINI: If you're going to -- if you're going to point that way, which is perfectly fine, you'd better put the mic on, so he can --

MR. STRYHAL: Thank you. I think I'll hold it down here, and then you can hear me.

Okay. If you look at the compliance table, you will see notes, which we will go to, you will see where we show if the general design criteria, the code, if a -- and I'll look at this because it's hard to see it down there, too. If a code or a regulatory guide is applicable to this plant, or if we've taken not so much exception but -- or in some cases exception to it because of the design, or if the IEEE standard that's currently endorsed wasn't applicable to the design, for instance, of the batteries that we're using, we have noted for these items the IEEE standards that we are applying.

If you go to the second page, it continues with the list, and it has these notes. Note 1, noted criteria are applicable to multiple units only and are not applicable to the single-unit ESBWR. Even if there's going to be dual units built on a site, they do not share any components within the plant.

Item 2, the criterion is applicable only to PWRs, and, thus, not applicable to us -- steam generators, pressurizers, etcetera. Item 3, the ESBWR standard plant does not have safety-related diesels and, thus, this criterion is not applicable to the ESBWR.

We had a fourth item which we deleted because of -- as we progressed forward with our changing around of the COLA items. The fifth item is covered by 10 CFR 50.34 -- two areas. So we do have like NUREG-0737, which has that item and it's not applicable to our power.

Six, not applicable to ESBWR. It applies only to pending applications at February 16, 1982, so it was an old standard that isn't applicable to us. Seven, the safety-related UPS system and the safety-related 480-volt AC isolation power centers are included in the DC onsite applicability column. Reason being is the AC isn't required for the safety functions.

We use the isolation power centers only to isolate the non-safety-related RITNESS or just normal power coming in from the safety-related components, so that they are not affected in any way by any of the actions out within the plant.

Now, we went through -- Section 8.2 has no open items, but you go to the next slide, you -- you hear now -- you can see that we have listed 10 applicant items to ensure that they catch these in Section 8.2. And in writing the DCD, we have noted in the description of these items where we expect to see them blend in, so that they blend in with what we have committed.

The changes that we made -- and I'll jump to this -- between Revision 3 and Revision 4 were all editorial, grammatical, pagination, fixing figures, so that they were bolder, darker, clearer, going through our descriptions as you look at figures to ensure that what you looked at and what was described were clear.

Many of the changes were like 8.2.4, it used to be .1. It's dash 1, dash A. These are all applicant items.

When you go to the onsite power -- Ira discussed this -- our batteries, if you were to look at the IEEE standards, etcetera, are not the standard battery that has been used. We wanted more ampere-hours with the high voltage with less footprint, and I wanted batteries that were more reliable, more durable, could take more bang for the buck.

These batteries were DOE-developed and used by DOD and are now commercial. I have selected the best quality of this battery for its characteristics.

Just a side note -- you can drop the

battery off the building, and then you can shoot a hole in it, connect to it, and still get the full ampere-hours out of it if you had to. That was part of the mil spec requirements.

We don't expect to do that, but if we had a seismic event --

(Laughter.)

Yes, if you have a seismic event, as has been proven with these batteries in Asian DOD sites -- Japan and all through those areas -- they just smile and take it. It doesn't hurt them. We are --

MEMBER SIEBER: The cases are not glass?

MR. STRYHAL: No. The cases are polypropylene. The case --

MEMBER SIEBER: But you can still see in them.

MR. STRYHAL: You cannot see in them, and you do not have to see in them. They are --

MEMBER SIEBER: How about accumulated flakes of stuff that --

MR. STRYHAL: It doesn't work that way. These are valve-regulated, lead acid batteries. You take a calcium lead acid battery, you improve it, you put it with glass -- absorbed glass mat around the plates, you make it longer, the plates can move, the plates don't hit anything, you get none of this residual decay into -- and flaking. You do not have to check electrolytic level.

These batteries also have a high safety factor in that they do not produce the hydrogen as the vented batteries do. During their normal float cycle, they will only produce one percent of the hydrogen that was produced normally by a vented battery, if that much.

They are capable of absorbing at least 99 percent, if not more, while they're on float. This battery will qualify at the same temperatures as your past vented batteries, will buy them capable of supporting the full load at 50 degrees Fahrenheit. We will not operate them above 76 or 77. They will normally be kept in a room at 68 to 72 degrees, so they will always have their full capacity plus.

I have bought batteries that are almost twice the amount of capacity we are going to need for 72 hours, because I don't trust the rest of the people. And you never have enough electric, air, and water in a plant. So we have the capabilities of undoubtedly exceeding, but I'm going to keep that, because we are not completed with our detailed design. When we know the load profile, we'll know where we are.

MEMBER SIEBER: I take it the high vac for the battery room is supplied by the battery?

MR. STRYHAL: No. No. Our plant investment protection supplies HVAC for all areas in the plant, and these --

MEMBER SIEBER: So if you lose that --

MR. STRYHAL: If you lose all your AC, okay, site blackout, the batteries are putting out. They're not making heat now. They're only generating a small amount of heat when they're on their float charge. They'll be floating at about 2.24 volts per cell, about 262 volts. The battery charge will be less than what's coming out of the rectifier, which is why it stays on its side. The rectifier voltage can't go over and go into the battery charge. They float without supplying any load. There are no DC-independent loads.

So when we -- so Ira eloquently talked about the one open item. We do have an ITAAC that when we know all these loads we will press the complete battery profile along with the rest of the tech spec tests required to bring this -- to put fuel in the plant. As soon as we do know his loads, hopefully, I won't scale the batteries down. We will look at other aspects of what we're doing.

MEMBER SIEBER: Is the lifetime of a battery like this roughly equal to or better than or --

MR. STRYHAL: I can tell you that batteries of this nature, I have had reports that at 18 years they were still greater than 100 percent of their design capacity. And like the past batteries were 12, 13, 15 years, up until when you changed them all out at 20 years, you were jumpering out cells and changing cells, that doesn't happen here. These batteries will last surprisingly longer, as long as you maintain the temperature when you're charging them, and the charge voltages are regulated right.

And as a clarification to what Ira was saying, if you want to equalize this battery online, the inverter will be sized from 200 to 300 volts. The maximum charge will be in the 280 range. The inverter won't care.

I can -- but normally, the battery will stay fully charged, and it will be at the periodic two-year testing or whatever for the battery during online, all of them, but you will then run it through its cycles, take a division out of service, check everything while you're at it, and then bring it back into service.

MEMBER STETKAR: If I could ask, since John opened up the issue of its package, it's an area that I've had some questions about.

You mentioned that the DCIS cabinets themselves are distributed between the control building and the reactor building, depending on, you know, whatever functions are used. And I look -- I read about the control room envelope, or whatever you call it, ventilation cooling system and was pretty doggone impressed with it. It seems to be quite well thought out.

What about environmental conditions in the other plant locations that contain things like, in particular, the inverters and the DCIS cabinets? How are those areas maintained at acceptable operating temperatures, including temperatures inside the cabinets, for 72 hours?

MR. POPPEL: This has been a source of both RAIs and confusion. In normal operation, the normal PIP HVAC systems, you condition everything. So everything will be found in the normal powerplant environment.

In a safety -- in an accident situation, when there is no offsite power, the DCIS is designed to accept the temperatures of the room it's in, or vice versa. In other words, we're qualifying the DCIS to x -- I think the number is like 60 degrees C. I don't know the exact number.

And either it will be located in a room that is 60 degrees C or less in an accident, or the room will be modified as necessary to not go above it passively, which can be done with things like fins and stuff like that. But so far -- and it's a pre-calculation, it's not finalized -- the worst-case temperatures in the building are 66, and that's for a very short time.

So the answer is passively, we accept it. The reason the control room received so much attention was it was the operators --

MEMBER STETKAR: Yes, I understand that, but --

MR. POPPEL: -- 60-degree operators don't exist, but 30-degree ones do.

MEMBER STETKAR: I'm aware of -- you know, this is digital stuff, and it is pretty doggone sensitive to temperatures. And I'm aware of plants -- a particular plant that after they started operating had to increase the size of their ventilation systems by a factor of three to maintain -- and those were active ventilation systems -- to maintain the temperatures within acceptable ranges inside the cabinet.

So this isn't -- this isn't a minor concern. And you do have some pretty significant heat sources, namely the inverters themselves, pumping heat into whatever rooms -- wherever they're located. So what I'm hearing is that you really haven't finalized the design yet to ensure that, indeed, purely passive heat removal will indeed keep these things cool, because you don't know -- you haven't done the analysis yet.

MR. POPPEL: And you can't until you know the exact heat loads in the room.

MEMBER STETKAR: Okay.

MR. POPPEL: The inverter heat load that you're talking about is essentially the inefficiency of the inverter.

MEMBER STETKAR: Well, sure.

MR. POPPEL: The rest of it --

MEMBER STETKAR: Sure, sure.

MR. POPPEL: And it matters if the inefficient -- it's a 30 kW inverter being inefficient or a 50.

MEMBER STETKAR: Sure.

MR. POPPEL: And so, therefore, you can't finalize a calculation. On the other hand, the generic room profile is the temperature rises without HVAC. And then, as it gets higher and higher, the heat gets driven into the concrete, and then it levels out.

MEMBER STETKAR: Sure. But it depends on the size of the rooms that you have.

MR. POPPEL: Yes.

MEMBER STETKAR: I mean, you know, how well they're compartmentalized against fires and flooding and those things, too.

MR. STRYHAL: Ira, part of the situation is these rooms are below grade level, number one. Number two, when we come out with this profile, you're going to find that where 99 percent of these solenoids are energized, and you have the biggest load when you're not in a site blackout situation, within seconds, minutes, a big portion drops off to where we're monitoring.

If we had loss of coolant accident, where we had to go off the ICS, you'd have your blip and back again. So the actual load on the inverters, if we go to a site blackout, drops off once these safety systems are activated to just monitoring.

MEMBER STETKAR: What fraction of the inverter load is the normal DCIS power supply?

MR. POPPEL: Probably about 95.

MEMBER STETKAR: There you go. Now, the DCIS is normally operating, though, right?

MR. STRYHAL: It's 95 percent of the load, but it's not 95 percent of the inverter --

MEMBER STETKAR: Okay.

MR. STRYHAL: -- capability.

MR. POPPEL: Well, we need to put this in perspective. Other than an external line break, okay, which will wipe out a division, as you can imagine, but not affect the other divisions, if you just have a normal LOCA inside containment, okay, so basically -- and a station blackout, you are left with a situation of, say, four inverters running as the only source of power in a plant.

And so if they are, say, 40 kW on the average each, that's 160 kilowatts spread out over the reactor building and the control room.

MEMBER STETKAR: Well, not if it's completely -- it is if it's completely open. It's not if the inverters and things are in little closed rooms. That's my whole point is that if these are located in hermetically-sealed fire, flood, tornado, everything proof, concrete rooms with big, solid, thick, concrete walls, as people design many plants, and you have a heat source and heat-sensitive equipment inside that room, it gets hot in the room.

It isn't the whole -- it isn't 170 kilowatts spread over 10,000 cubic meters of open air. It's whatever is in that room is the concern. And it's not a LOCA; it's how much heat is that equipment putting out during its normal operation, including the power supplies inside the cabinets and things like that, compared to what the heat removal capability from that localized environment is.

That's the -- that's my concern, and it has that analysis been done because, I will tell you, I've looked at many plants and the answer was, no, it was not done --

MR. POPPEL: It is a --

MEMBER STETKAR: -- during the design.

MR. POPPEL: -- requirement for it to be done during the design. Okay? We actually have a code --

MEMBER STETKAR: But it has not yet been done.

MR. POPPEL: Yes. I mean, for example, when I gave you the number like -- I can't remember whether it was 63 or 66 degrees C, the worst-case room, as you -- as you might imagine, was the inverter room.

MEMBER STETKAR: Sure.

MR. POPPEL: Most of the -- first of all, when you say small rooms, thick concrete walls, we have very large rooms with thick concrete walls. Okay? But the average DCIS room has very little equipment in it. Okay?

The inverters are an active source of heat, so here may be a room down in the basement that has a kilowatt in a very big room. Nevertheless, per room we have to -- and there's a code for this called GOTHIC, which basically says here's the room characteristics, the room heat sinks, etcetera, etcetera.

Here is the source of heat in the room, and then we will do a calculation that shows the room temperature versus time. And at the end of 72 hours, the equipment must either meet the qualification of whatever that temperature is or the equipment must go someplace else.

CHAIRMAN CORRADINI: So we'll -- we'll still have a crack at this later I guess is what --

MR. MILLER: There's an ITAAC for it that will be --

MEMBER STETKAR: Well, the only thing I noted is there didn't seem to be an open item or -- I didn't have access to all of the RAIs, so I didn't -- I personally haven't seen whatever other discussions have followed between you and the staff on this particular issue.

MR. POPPEL: Just like electrical, you know, in the end I have to tell John, "Here's how much power the DCIS is taking," because he's got to -- it's a support system. In the end, both active HVAC as well as passive HVAC is a support system. We have to give them the information, and they have to go and show that it's all okay.

We are expecting it to be okay, because our enveloping calculations assumed large powers in those rooms, just to see what would happen. We expect it to be okay, but there is the potential that if it's not okay, fix the room, move the equipment.

CHAIRMAN CORRADINI: So just to hone in, just so I'm clear, so this is to be done. And you said something in the conversation I want to get clear. So this is the equivalent of what I would consider an equipment qualification. And what are you using for the analysis of that?

MR. POPPEL: Well, in --

MR. MILLER: Commercial GOTHIC code. There's a program -- GOTHIC -- that most of the powerplants use now.

CHAIRMAN CORRADINI: Oh, I know about GOTHIC.

MR. MILLER: Or the coping analysis or --

CHAIRMAN CORRADINI: It used to be called TRAC -- COBRA something.

MR. MILLER: Right.

CHAIRMAN CORRADINI: Yes.

MR. POPPEL: Since we have basically done our scoping calculations, again, I don't remember the exact numbers, but assuming, like we said, that there's 5 or 10 kilowatts in each room, and said, "What do the rooms do?" okay, and the worst-case room was 66 degrees C, and so we have a profile qualification for an initial qualification to the electrical equipment and we may make this better, define it down.

It says you should qualify it for this, and then, when the equipment is designed and we know the actual heat load and rerun the calculation, we expect it to be better, but it could be worse, in which case either the equipment changes or the room changes or we move the equipment.

CHAIRMAN CORRADINI: And so just to finish this off, so there will be a topical report -- in what form would -- if John wanted to find more about it, in what form would we find it, in a topical report, or where would it be?

MR. MILLER: It would be a design calculation.

CHAIRMAN CORRADINI: Okay. But buried in a topical report, not in the DCD?

MR. MILLER: It's in the implementation

process. When we buy equipment, okay, we get the heat loads from the equipment, we take that heat load data, put it into this GOTHIC program, run the analysis and come up with the coping, okay? So it's not an LTR, but -- Rick, do you want to speak to?

MR. WACKOWIAK: Yes. In Rev 4 of Tier 1, we added Section 3.8 that includes the ITAAC that covers this topic.

MR. KINSEY: And this is Jim Kinsey from GE. I guess the other point is you'll get another chance to discuss this with us when we -- when we come in with the support systems discussion, when we go through that chapter.

CHAIRMAN CORRADINI: Okay.

MR. KINSEY: We'll be sure that we, you know, cover this as a point of emphasis at --

CHAIRMAN CORRADINI: All right.

MR. MILLER: Basically, as new technology becomes available to us, heat loads drop power, okay, requirements -- so we sort of, you know, not picking the equipment that --

CHAIRMAN CORRADINI: No, I understand. I just want to make sure we close it in such a way that we don't forget it and know where to look for it.

MR. MILLER: And the ITAAC and that section that Rick just mentioned, we'll make sure that you have the right for inspection or audit to --

MR. STRYHAL: There's one more item. When we initially designed this plant, the inverters were much larger, the battery chargers were larger, because we had 480 buses and we had active pumps and motors that have gone -- we had active MOBs that have gone away.

So the inverter sizes have respectively dropped based upon the initial general arrangement design and inverter size. So this was --

MR. MILLER: We know right now from our elimination of all of the MOBs and the inverter sizing going down, the calcs are somewhat conservative, so --

MR. STRYHAL: Okay.

MR. MILLER: -- hopefully we'll be going in the right direction.

MEMBER BLEY: That's real interesting, because I -- most existing plants where we've looked the only calcs we've seen are the normal or emergency operating loads with AC available. And people just hadn't looked at this issue, so it would be real interesting to see it.

MR. MILLER: Yes. We are still into coping calculations to make sure the equipment that is in those rooms is --

MR. POPPEL: You have seen us before in active plants with coping analyses for station blackouts where the assumption is even that diesel-driven HVAC isn't available. And they have to show that whatever they are using to cope -- and so we're coping, if you will, all of the time.

CHAIRMAN CORRADINI: Other questions?

(No response.)

Okay. Thank you very much. I'm going to turn to the staff and ask them -- Amy, did you want to bring your people up now? We'll go through 12:30 and finish it off.

MS. CUBBAGE: I think that would be a great idea.

CHAIRMAN CORRADINI: Since you have everybody here now.

Thank you very much.

MR. POPPEL: Thank you for the opportunity.

CHAIRMAN CORRADINI: I recognize the face now. Go ahead.

MS. BERRIOS: Good morning. Like I said before, my name is Ilka. I work for the Division of New Reactor Licensing. We have Sang Rhow that is the reviewer, and Ian Jung, the branch chief.

We are going to be having a brief summary of the staff review of the ESBWR application. In this case, we are going to discuss Chapter A, electric power. And as before, we'll be happy to answer any questions from the Committee.

The review team for this chapter was myself, Ilka Berrios, Project Manager, and Sang Rhow, the reviewer.

As before, we are going to be discussing the applicable regulations that were used during the review, RAI status, some technical topics, open items, and the COL action items.

Besides the regulations that were used during the review, we have some design criteria, we have federal regulations, SECY papers, reg. guides, branch technical positions, and the standard review plan.

The RAI status on this case -- we had a total of 116 RAIs, and from those ones 115 are resolved, and we just have one open item, which Sang

Rhow is going to be discussing.

Now I'm going to turn it over to Ian Jung, who is going to have an overview.

MR. JUNG: Good morning. This is Ian Jung. I'm the Branch Chief of the Instrumentation and Control and Electrical Branch. Sang Rhow was assigned to take the lead on Chapter 8. Sang Rhow is also working on some I&C areas.

Staff used the standard review plan for Chapter 8, which is self-sufficient, meaning that it contains all of the regulations and the staff guidance and reg. guides and branch technical positions that Ilka just went over. Staff also had to do a -- really, you know, a detailed review of a lot of design features.

Also, we -- being a passive design there was a -- clearly, the scope of our review had to shift quite a bit from much broader design features in our current active plans versus just passive plans, where safety systems are really, you know, related to a battery -- uninterruptible power supply, UPS, and battery. That was a significant change.

Also, GE explained some of the even regulatory guides and the standards are not even applicable for this design. For example, a lot of the, you know, IEEE standards on regulatory guides are related to diesel testing, qualification, and type of activities. So our review had to be also designed in such a way -- the safety system portion of the design -- you know, design is reviewed appropriately.

But, at the same time, we don't want to clearly have a situation with non-safety systems also impacting safety systems. So we looked at basically all of the required, you know, GDC requirements related to separation and independence, and GE went over yesterday and today regarding all of the separation and four corners. And I think, overall, safety systems design of the GE -- ESBWR overall is quite robust and overall sound.

We still -- we went -- we had a lot of the II questions, and, you know, all of the questions including I think HVAC. We had some discussions, so some of those areas are sort of cross-cutting with the HVAC reviewers and the EQ and some other aspects. So we'll take that as an action to, you know, make sure that we follow that up also.

MEMBER SIEBER: Do you know enough about the electrical design to be able to determine what the

HVAC capability has to be? Probably not, right? You don't know the room sizes, you don't know the heat loads.

MR. JUNG: No, not at this point --

MEMBER SIEBER: Okay.

MR. JUNG: -- as GE explained, some design features and floating load profile, some of the information might be needed I think in my -- I think we still have an open item, ITAAC.

MEMBER SIEBER: And you can actually say the same thing about your open item, right?

MR. JUNG: Yes.

MEMBER SIEBER: You just don't know enough --

MR. JUNG: That's right.

MEMBER SIEBER: -- to be able to answer that today, right?

MR. JUNG: That's correct.

MEMBER SIEBER: Or even in the next month perhaps.

MR. JUNG: Yes.

MEMBER SIEBER: Okay. Thank you.

MR. JUNG: In SRP we have -- GE just went over same structure, but the SRP has four main sections -- 8.2, offsite power system; 8.31, onsite AC; 8.32, onsite DC; 8.4, safety analysis -- for example, station blackout. Staff reviewed those sections, and our safety evaluation with open items addressed each of those sections.

As I mentioned, ESBWR design, being passive, requires, you know, the UPS as the only source of the power for design basis events, which is quite different than -- from the current design. The main purpose of our staff review is to confirm the compliance of the -- by the applicants regarding applicable regulation.

I wanted to emphasize "applicable." As I said, there are certain -- most of the current regulations apply for some -- some other areas, except for reg. guides and IEEE standards. There are certain areas it wasn't really applicable.

But with that, I'll turn over to -- turn it over to Sang Rhow, who has the responsibility.

MR. RHOW: My name is Sang Rhow. I reviewed Chapter 8 as the technical reviewer. I want to give you -- just a brief description about the offsite power supply system. I think GE presented very detailed -- I think to me it's too much detail --

information to you probably.

Based on GDC-17, ESBWR design has two independent offsite power supply systems from the switchyard. And these -- from the switchyard and through the normal preferred power supply, they call the two offsite power supply systems "as the normal preferred power supply." Another one is alternate power supply system.

Each preferred power supply system has two three-phase step-down transformers. That's very unique. That means actually a four-unit alternate transformer in the -- to provide offsite power supply to the onsite as the "features" on the ESBWR.

And there was -- oh, I'd like to give you a little bit full load rejection capability on the ESBWR. There is a both way -- if you have any problem on the grid system, and on the grid switchyard there is usually -- industry used to break in half scale. You isolate the -- any point on the grid system, trip the breaker, stay at -- still, there is a generator breaker is closed. Therefore, these main generators provide onsite load through the unit alternate transformer.

The other way -- onsite generator had a

problem -- for example, like a differential problem or a grounding problem, any problem in the onsite generator -- still, they have a back configuration. They are a well, good, sound power supply system, in the ESBWR.

Next slide.

I'd like to discuss the key features of on -- onsite AC power supply system. The ESBWR has a full, independent -- circulated 480 isolation power center connected to the 6.9 kV plant investment protection buses through the 6.9 kV to the 480 stepdown transformer.

I need Slide 10. I think already GE showed a very good diagram, but I just copied from the GE DCD package. There is one division. I didn't put in there all of the potential divisions.

I want to give you a little bit more explain additional to the GE explanation. Keep in your mind normal power supply as long as the --

MEMBER STETKAR: You have to use the mic. hold this. You have to start thinking like a lounge singer, you know?

(Laughter.)

MR. RHOW: Yes. As long as AC is

available, this is a normal power supply system through the UPS. This is a very good feature. Why -- you know, some -- even the NRC guides, why they are stupid design? Why --

(Laughter.)

Why they don't go to the AC to DC and the DC to AC? Why such a very stupid design? There's a key. This load is a DCIS -- is barely sensitive to the harmonic distortion. Therefore, we call that that -- this is the power system conditioner. Convert the AC to DC, just the third harmonic -- keeps the harmony all this kind of distortion, and go through the DC to AC. This is good feature for the special digital control system in the ESBWR.

And then, something happened in the -- something happened to AC source. So ultimately this will take over, because it is a charging system -- there's a diode. Which of the power is bigger ultimately will -- that's the connectivity that the high voltage.

Normally, charging voltage is, what, 2.17 or 2.2 percent. This charging voltage is 2.06 or 2.07 percent. Therefore, anything this is losing for -- anything charging voltage is losing, there is automatically DC power supply takeover. The AC system takes over the -- for this.

And already GE explained better anything about the problem in here, this is the static switch. Switch is here, and this connects to the regulating transformer. What is that thing in here -- rated the voltage, maintains the rated voltage, maintains the rated frequency, also same to -- this is filtering out harmonic distortion.

Another is a regulating transformer -- features of the regulating transformer is to maintain all the time -- all the time, to provide a high quality of work power supply -- power to the UPS. This is such a good feature, not only utility combined with this one to -- how we combine with this one, connect here, put the charger here. It provides a charging current at the same time, same time as DC gives power to the inverter and going to the UPS.

But ESBWR is a -- is a special feature. It separated electric power and goes to the inverter. Then, we have a -- he already explained here, there's a two bank of battery system here to here in the one division. That's good features.

Also, they are separate all there up to

the UPS. Completely separated, not independent -- I cannot say independent, because the power source is one power source from the isolation power center. But, still, anything wrong -- we have a lot of reliability on the -- each division.

One thing that -- I think GE presented something I don't agree with them. He said -- I don't know if I understand correctly. He said this charger -- this is a 72 hours rated battery. Is that different from the 36 hours rated battery?

Reason is, first of all, how fast they will charge is different. Inverter is different. More current flow, instead of 72 hours, they put 36 hours, same battery size. Current is much higher, charging current is much higher -- twice more. Therefore, we ask GE as to the loading -- loading profile on each bus.

The reason is I like to see actually how you're going to divide this UPS power supply to --

CHAIRMAN CORRADINI: I heard what you said, but I don't -- you're going to have to summarize it for me. You're saying -- what you don't agree with is what exactly? Or you don't understand the profile that they're designing to?

MR. RHOW: Okay. When you figure out the battery size, what is the unit ampere-hour? Am I right? Ampere-hour?

Therefore, 72 hours rated battery you will use a 36 hours battery -- battery, rated battery, and then you start increasing it to twice more in the current.

CHAIRMAN CORRADINI: Okay.

MR. RHOW: You can even increase it to twice more current, you have to -- you are charging, and the bigger inverter. That's what I'm --

CHAIRMAN CORRADINI: Okay.

MR. RHOW: -- trying to say.

CHAIRMAN CORRADINI: Okay.

MR. JUNG: I think earlier GE mentioned about some confusion about this --

MR. RHOW: Yes.

MR. JUNG: We had actually an RAI on this, and our -- based on the RAI and some conference calls, our understanding was actually each one of those batteries were actually 72-hour batteries. Today, they explained it is actually 36 hour. Each we have a safety -- potential safety impact, because --

MR. MILLER: Yes, I think there's

confusion there. I think John can shed some light on it.

MR. STRYHAL: I'm John Stryhal, GEH.

MR. MILLER: There are still 72-hour batteries with the load profile in --

MR. STRYHAL: When we design these, and when we have our system design specifications, each rectifier, i.e. the portion that is filtering that was described, each rectifier will be able to carry the complete safety-related load as if the DCIS and all loads were on one of those two buses.

Each battery is currently sized for 72 hours, and right now, preliminarily, they potentially can reach it with the current size I have. As I said, I alluded to it. They are probably twice as large as they will need to be. Each inverter can carry the full load. Each battery charger, if the other rectifier was out, the other side was out totally, will be able to carry the full load on one of those buses.

We designed overly robust, because we don't know where we're going to be at the end. So I selected items that were actually much larger, I hope, than we will ever need. We had batteries designed in the beginning for 72 hours worth of monitoring before we went to n minus 2, and only 24 hours worth of action.

Then, we realized we had actions and things that we may have to do later, such as line break and squibs, etcetera. I looked for batteries with a better profile, footprint, and these batteries I can stack up and I can put in three times or four times more batteries in one battery room than in the past with the old batteries.

MR. MILLER: John, I think the simple answer here is basically the batteries are designed, okay, to handle a load of 72 hours.

MR. STRYHAL: Yes.

MR. MILLER: And the load profile down at the lower bus, okay, will be in a calculation when we know the specifics from the DCIS equipment.

MR. STRYHAL: As Ira said, if half the equipment dies, DCIS and the other half of the cards are doing the same function. One of those sides in the reactor building will take care of it, but we're inoperable. We're functional, but we're inoperable.

MR. RHOW: That means they are going to -- same DCIS load provided two -- two power supplies to each DCIS load?

MR. POPPEL: Ira Poppel, GEH. Okay. Imagine DCIS was one thing, and it drew one watt. Okay? That DCIS thing has two power supplies in it, one fed from this 120 volts, the other fed from the other 120 volts. Those two power supplies are one watt. In other words, that DCIS thing can run off of either.

Okay. Now, normally, each one will be supplying about half a watt. Now, move back to the inverter. The inverters normally are supplying half a watt, half of the load on this one and half of the load on the other one. They are sized each for one watt, meaning that the other inverter could go away, just like the other power supply in the component could go away, and the component, i.e., the DCIS, would continue functioning. Okay?

The battery chargers are kind of a misnomer, because we're not taking any power from the batteries. So, in other words, basically the battery chargers are sized on how long it takes to recharge them, because normally all they're doing is supplying a float charge.

So it's when you say a question of they

have to be twice the size, it's -- you have to decide whether you -- if the design basis is you have to recharge the battery in 20 hours, or whether you do it in 10 hours, but of course if you have the AC power available to recharge the batteries, you're not running the inverters off the batteries, you're running them off of the AC.

So, therefore, it's irrelevant how long it takes to recharge the batteries, because the DCIS is functional as soon as AC power is available. That leaves you with the batteries. There's two batteries. Not counting the inverter if you will, the batteries are each normally supplying half a watt, using our example. Okay. They can each supply half a watt for 72 hours.

Now, let's assume the battery died, or the inverter died, or something happened in one of the power feeds. That means the load on the other inverter and the other battery would go from half a watt to one watt. Therefore, it will no longer last 72 hours, because it's taking twice the power out of it.

Now, it's not exactly linear. Battery discharges aren't linear. So together the two batteries will last for 72 hours. And as John said, they're considerably oversized. One of them will last, by definition, 36 hours, but probably considerably longer than that.

MR. MILLER: Ira, I think you need to stay on the 72-hour. Once we lose one set of batteries, okay, we're in a tech spec condition and we go to, okay, our n minus 2 design, where we have still another set of batteries for single failure criteria.

MR. POPPEL: As I said, we believe when the battery -- when one of the two batteries goes out of service, even though nothing is -- the division is still completely functional, just because -- by definition if one battery is out of service, we consider the division out of service rather than argue half power, 36 hours, 72 hours. It's just out of service until we fix it.

MEMBER STETKAR: But just for my clarification, just to kind of keep it simple and so I understand, if -- I think what I hear you saying -- and I just want to make sure I understand it -- is that assume that the inverter that is up on the screen there powered from DC bus 11 is -- evaporates, is not there. And we have a station blackout at time T_0, so

I'm feeding DCIS from this division from battery 12.

At 37 hours, I have zero power for that DCIS division, is that correct?

MR. POPPEL: Yes.

MEMBER STETKAR: Okay.

MR. POPPEL: Approximately.

MEMBER STETKAR: Thanks. Thank you.

CHAIRMAN CORRADINI: But the way they're --

MEMBER STETKAR: No, no, no. That's -- just sizing battery capacity -- this is electrical, not licensing.

MEMBER SIEBER: You can still power that from your diesels, right, your chargers?

MR. POPPEL: Oh, yes. I mean, the diesels represent AC to the whole isolation power centers. The diesels are running diesel --

MEMBER STETKAR: I'm trying to clarify the size of the battery and the load on the battery.

MS. CUBBAGE: Right. And you still have the three other divisions.

MEMBER STETKAR: That's okay. I didn't ask that. I --

MS. CUBBAGE: Well, I --

MEMBER STETKAR: I just wanted to know this battery with a load connected to that battery.

CHAIRMAN CORRADINI: Why don't we keep on going.

MR. RHOW: Next slide. I would like to discuss about open items, what we have -- one open item. Already GE explained very well about open item. Therefore, I -- you don't need any more discussion about open item.

We are much more concerned about the battery size. That's why we asked them in the load profile, loading profile on the UPS bus, each bus.

There is three COL site-specific information items. One is administrative control for the first grounding circuit breaker. Second one is periodic testing over the power supply system and the protection systems. Third one is a maintenance rule program. These three items will be addressed by the COL applicant.

Now, GE gave us a lot of good features on the ESBWR. As far as the NRC is concerned, I'd like to a little bit summarize their robust design features. I didn't put it in your slide, but there is three power supplies to the UPS, because UPS is a key core safety-related power supply system for the ESBWR. Therefore, after the drawing, there are three power supply systems, better known as the two 72 hours rated battery bank of each bus.

Third one is even though we don't need any standby diesel generator as the emergency diesel generator, like operating reactors, I call the traditional reactors the active reactors for the -- their case, GE put the standby diesel generator as the RITNESS program. RITNESS program is our regulatory treatment of the non-safety system program.

I'll go through the diesel review item to the conclusion -- the offsite power system and the onsite AC power supply system, and then Chapter 8.4, safety analysis concept, safety analysis. That's misleading. I apologize; that title is misleading.

Anyway, this is very unacceptable. Due to the open item about battery size, staff cannot conclude if the onsite diesel power supply system is acceptable.

Last one is COL applicant will address all COL site-specific items.

Now, do you have any questions?

(No response.)

CHAIRMAN CORRADINI: Any questions?

MEMBER SIEBER: It seems to me that there is so much redundancy and diversity --

MR. RHOW: Yes.

MEMBER SIEBER: -- in the system --

MR. RHOW: Yes, absolutely.

MEMBER SIEBER: -- that a good PRA person could go through and say, "You really don't need this, and you don't need that, and you don't need that." And is there a chance that you may modify and slim down your design before the design certification is completed?

MR. STRYHAL: John Stryhal, GEH. We are in the design phase. Our intention now is to hold the size we have and eventually would go up if we have to to meet what our design basis is for the DC system.

MEMBER SIEBER: Okay.

MR. STRYHAL: We currently do not contemplate reducing the size. The n minus 2 system requires the four divisions. We require, because of the DCIS, two sources of power, so that it has its comparison logic. So we do not intend at this time to even contemplate reducing it.

MEMBER SIEBER: Now, the other thing that is driven by some kind of a risk calculation is what your maintenance rules for the plant operator will be. You know, if it's not risk-significant compared to other things in the plant, then you can have it out of service for a longer period of time. I presume that the staff, in the process of developing tech specs, would take that into account, that a licensee may be tempted to do that.

MS. CUBBAGE: This is Amy Cubbage. Are you talking about the first one being out of service?

MEMBER SIEBER: No.

MS. CUBBAGE: Oh, okay.

MEMBER SIEBER: I'm saying, you know, you can look at it and say there's lots of diversity and redundancy here. Therefore, I calculate that I don't change my risk if I leave it out of service for a month or two months, as opposed to working overtime and working the weekend and stocking spare parts and things like that.

MS. CUBBAGE: Right. Would the --

MEMBER SIEBER: And those are choices that are made on an economic basis.

MS. CUBBAGE: Right. And with the first -- I believe Rich may have misspoken. When the first division is taken out of service, they do not enter a tech spec LCO, so they would be controlling that administratively. It would be the second one that would get them into the LCO.

MEMBER SIEBER: It's a maintenance rule that's addressed --

MS. CUBBAGE: That's right.

CHAIRMAN CORRADINI: John?

MEMBER STETKAR: I have a question that's actually related to the non-safety DC system, because that's part of the electrical system, and we talked about offsite power and all of the non-safety AC power. But non-safety DC system -- this is probably for GE, so help me out on this. Non-safety DC system batteries are rated for two hours, is that correct?

MR. POPPEL: Yes.

MEMBER STETKAR: Okay. Does the non-safety DC system supply control power, and by "control" I mean operating power, for the trip and close coils on all of the AC switchgear buses, hit buses and --

MR. POPPEL: Yes.

MEMBER STETKAR: -- 13-point --

MR. POPPEL: Yes.

MEMBER STETKAR: Yes? So if we have a station blackout, loss of offsite power, diesels fail to start, at -- after two hours, can I operate any of those circuit breakers?

MR. POPPEL: Although the circuit breakers have not been chosen yet, derivatively from like the ones we chose at Lungman, they are capable of manual operation.

And, in addition, the diesel generators are capable -- they are air started, as you know, and they are capable of being started manually without the DCIS. So we believe that we can open all of the breakers, we can start the diesels and get AC power back, close the breaker to the chargers, and then recover the electrical system, the non-safety.

MEMBER STETKAR: Okay. So that's -- but if the diesels are apart in pieces on the floor.

MR. POPPEL: Oh.

MEMBER STETKAR: Let's say the diesels fail, they do not work --

MR. POPPEL: And AC power is lost, but then --

MEMBER STETKAR: -- for longer than two hours --

MR. POPPEL: But then comes back.

MEMBER STETKAR: -- the grid comes back at two and a half hours, can I operate any circuit breakers inside the plant to close circuit breakers?

MR. POPPEL: Manually, not from the control room.

MEMBER STETKAR: How do you do that manually? I've never seen a circuit breaker that can be closed mechanically manually installed in a nuclear powerplant.

MEMBER SIEBER: You can only do it once.

(Laughter.)

MEMBER STETKAR: And you can do it, because I want to live.

MR. POPPEL: You are talking about closing. You agree that they can be opened.

MEMBER STETKAR: Oh, I fully agree they can be opened. Any circuit breaker can be opened.

MR. POPPEL: After that, we haven't delved into it very much, but you may have seen passing reference to portable generators that are around the site.

MEMBER STETKAR: Right.

MR. POPPEL: And those can, in fact, be

set up to charge the -- you know, and do it.

MEMBER STETKAR: Okay.

MR. POPPEL: That's kind of in extremis.

MEMBER STETKAR: I was just curious about the -- I just wanted to make sure that I understood the design.

MR. POPPEL: But if -- again, if offsite power goes away, the normal response of a plant is to run from the main generator.

MEMBER STETKAR: Sure.

CHAIRMAN CORRADINI: So let me ask a question at this point. So to close the action item, I was looking at how it's written in the chapter and how you stated it here is slightly different, but that's fine. To close the open item, then, we're going to -- you're expecting to see a load profile calculation, so that you're comfortable that they can make it within the 72 -- they can do it within the 72 hours, the full 72 hours, is that as I understand it?

MR. RHOW: Yes.

CHAIRMAN CORRADINI: And that will be supplied with a new DCD or a separate communication to you just to show -- to do the calculation?

MS. CUBBAGE: GE has not committed to a

response yet for that RAI, so we're waiting for their response, and then we'll review it and report back to you on what -- how this issue is resolved. I mean --

CHAIRMAN CORRADINI: Well, the reason I'm asking it like this is I'm trying to understand the dance you do, which is in the first open item in Chapter 17 there will be an expert panel. The expert panel will identify SSCs.

MS. CUBBAGE: Right. And in that --

CHAIRMAN CORRADINI: In this case, it's to be determined how this will --

MS. CUBBAGE: Exactly right. In the first case, GE has committed basically to a response. They have responded to the RAI, but we have not yet received the detailed information, so it's still open. In this case, we have not received a response from GE-Hitachi, and so we're waiting for that response.

CHAIRMAN CORRADINI: Okay.

MS. CUBBAGE: I don't know if GE would like to elaborate any more on their plans, but that's all we can say at this point.

MR. HINDS: This is David Hinds. I think we'll stick with that answer, that we will determine in the future, and are not yet at this point ready to commit to the actual response. We'll need to continue to work with the staff on getting an acceptable response to that RAI.

CHAIRMAN CORRADINI: Good. Great. Any other questions by the Committee -- Subcommittee?

(No response.)

Okay. I think we're adjourned for lunch. And as I understand it, we shouldn't start Chapter 2 until we said we're going to start Chapter 2. I think it says 1:30.

PARTICIPANT: 1:45.

MS. CUBBAGE: Actually, we're trying to get the staff available here to start whenever you're ready to start.

CHAIRMAN CORRADINI: Let's do it at 1:30.

MS. CUBBAGE: Okay. 1:30.

MEMBER POWERS: That's not the problem. The problem is that if the public --

CHAIRMAN CORRADINI: So it's got to be 1:45. Amy?

MS. CUBBAGE: Yes.

CHAIRMAN CORRADINI: It has to be 1:45 if we have people from the public attending, so we'll keep it at 1:45.

(Whereupon, at 12:02 p.m., the proceedings in the foregoing matter recessed for lunch.)

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

(1:46 p.m.)

CHAIRMAN CORRADINI: All right. Give us the thumb's up when you're ready. Sorry. All right.

MR. JORDAN: Thank you, Mr. Chairman, and good afternoon.

CHAIRMAN CORRADINI: Good afternoon.

MR. JORDAN: My name is Peter Jordan from GE-Hitachi, and this presentation will be on Chapter 2. I am the Regulatory Affairs Engineer assigned to Chapter 2, which deals with site characteristics and associated design parameters. And this presentation will be made by Dave Hamon, who is on my immediate right.

MR. HAMON: Okay. Thank you very much. As he said, I'm going to do an overview presentation on Chapter 2. We'll start out with an overview of the contents in it. Then, we'll go through some of the details of the design parameters that are covered in Chapter 2. I'll give you a summary of some of the applicable references from where we took these parameters, and then follow up with a summary.

Chapter 2, by nature, is a collector of data from -- that's input to analyses that are spread throughout the entire DCD. And, for instance, there's a lot of input from the seismic analysis that's part of Chapter 3. There's also input from the radiological analyses in Chapters 12 and 15.

So to the extent we can, we'll answer any questions you have, although if you get too deep into those subjects we might -- it might be better if we defer some of those to later discussions on those individual chapters when we have our experts here on those subjects. But we'll work through it as best we can here today.

Chapter 2 -- as I said, it covers site-related design parameters for the ESBWR, and in general it covers areas like meteorology, hydrology, geology of the site, seismology, geotechnical parameters, and then also looks at any potential nearby hazards that might affect the plant.

In Chapter 2 of the DCD we present some bounding parameters, and then the individual COL applicants will reference the ESBWR DCD, and then have to demonstrate that the parameters for their site are bounded by the parameters that we used in the ESBWR DCD. And then, they have to provide some additional information related to the specific SRP criteria for

Chapter 2.

Looking at the design parameters themselves, the requirements for this -- for the standard design come from 10 CFR 52.47. And if we start looking at individual parameters, the first one is maximum groundwater level, which we have assumed as .61 meters or two feet below plant grade. For maximum flood level or tsunami level, we're using .31 meters or one foot below plant grade. Both of those values come straight out of the EPRI utility requirements document, and they are also identical to what we used for our ABWR certification.

For precipitation, it's used for --

CHAIRMAN CORRADINI: Can I just ask --

MR. HAMON: Yes.

CHAIRMAN CORRADINI: This is more a clarification, since I'm not familiar with some -- so let's say a site is picked. Do they then have to modify the site to move things up to at least meet these standards? In other words, move the plant -- do you know what I'm asking?

MR. HAMON: Yes.

CHAIRMAN CORRADINI: Or just avoid totally and completely?

MR. HAMON: In general, the site should be able to meet those. If they pick a site that doesn't, then, yes, they would have to raise the base elevation of the building.

MEMBER POWERS: Or make appropriate compensatory measures.

MR. HAMON: Yes. Or --

MEMBER POWERS: They're just outside the design envelope, so you've got to do something about it.

MR. HAMON: Yes. It -- if they don't meet some of these requirements, it doesn't mean they can't build the plant. It just means it may potentially invalidate some of the analyses that we have done for the building, and we'd have to --

CHAIRMAN CORRADINI: They'd have to redo it.

MR. HAMON: -- that we'd have to redo the building design or whatever for them to accommodate it.

So -- so what we -- we've tried to pick parameters that we think will bound most of the sites that are likely potential sites for these plants, but certainly somebody might eventually come up with one that isn't bounded, and it would just involve some more work, taking deviations to the DCD and doing some additional analyses.

CHAIRMAN CORRADINI: And the EPRI requirements document has -- no, this is historical, so I'm not sure. The EPRI requirements document that you referenced has been looked at by staff, and there has been comment on it or approved or --

MS. CUBBAGE: Right. There was a safety evaluation on the EPRI URD many years ago.

MR. HAMON: Yes. Yes, we're using a 1997 version.

PARTICIPANT: That's when you were a pup.

CHAIRMAN CORRADINI: I figured that. I was waiting for a comment like that.

(Laughter.)

I'll take youth whenever I can get it. Thank you.

MS. CUBBAGE: And I've just been informed that that was NUREG-1242.

MEMBER POWERS: Naivete often goes along with it.

CHAIRMAN CORRADINI: Noted.

MS. CUBBAGE: Dr. Corradini, that was

NUREG-1242 with the safety evaluation, I've been told.

CHAIRMAN CORRADINI: Thank you very much.

MR. HAMON: Okay. Moving on, precipitation -- this is primarily used for doing the roof design of the buildings, and for rainfall we've assumed 49.3 centimeters per hour, or 19.4 inches per hour, and a short-term rate over a five-minute duration of 15.7 centimeters or 6.2 inches.

Those values are based on some National Weather Service publications, and they are also identical to the values in the URD as well as the ABWR certification.

We have also designed the roof scuppers and drains to limit accumulations on the roof to no more than four inches or 100 millimeters of rain.

In addition, we have also had to look at -- for the roof design to accommodate a 100-year snow pack, ground snow load of 50 pounds per square foot, and we have also had to design for 48-hour probable maximum winter precipitation conditions.

MEMBER POWERS: We have within the meteorological community now a hypothesis, substantiated by substantial amounts of empirical data, that weather goes through cycles. And there are a couple of major cycles that affect particularly the east coast.

And then, what one worries about is when those cycles reinforce each other, which may actually be occurring. And so when you say, "Gee, I use a 100-year snow pack," why is that meaningful unless I know that your 100-year snow pack affects the next 100 years, which is what -- the period that affects your plant? I mean, if that's a period of historically low points in these weather cycles, and now we're going into a historically high point, why would the 100-year snow pack or the 100-year wind storm or the -- worse yet, even the 50-year gust be the appropriate measures to use here?

MR. HAMON: Well, I guess for starters it's what we had available in the data. Clearly, you could put some conservative factors on it, and, in fact, there are -- typically in building design you've got some factors of safety that are applied to the design to help accommodate for some assumptions.

It may not match exactly what the conditions are, so -- but I -- unless -- I mean, we've got to try and find some way to come up with a number to use, and I don't -- I don't know how representative, these are our worst case or best case. I haven't looked at the data in that much detail.

MR. KINSEY: Excuse me. This is --

MEMBER POWERS: Well, it's 100 years, so it's --

MR. KINSEY: This is Jim Kinsey from GE-Hitachi. I believe the criteria that we used are consistent with the guidance in the SRP. I mean, that's really the -- our starting point.

MEMBER POWERS: Well, and the question is whether that guidance is any good or not.

MR. KINSEY: That would be a question for --

MEMBER POWERS: Oh, they'll get asked.

(Laughter.)

Their only advantage is it's getting telegraphed to them.

(Laughter.)

MR. KINSEY: They get a little bit more time to think about it.

MR. HAMON: But to answer the question, the reason we use that criteria is because it's associated with the SRP.

MEMBER POWERS: Okay. So what you're

telling me is you didn't think about it. You just used what was in --

MR. HAMON: Well, it's a combination of the SRP, and also some discussions with the staff. We have had some RAIs and back and forth on these parameters, and this is where we've settled on at the moment.

MEMBER POWERS: Okay.

MR. HAMON: Okay. For extreme winds, for the seismic category 1 and 2 structures, we're using a 100-year return, three-second gust wind value of 67.1 meters per second or 150 miles per hour. And for the non-seismic structures that are part of our standard plant design, we're using a 50-year return, three-second gust, which in the latest DCD revision has been updated to 58.1 meters per second or 130 miles per hour. In the Rev. 3 that was -- it was 110 miles per hour, so that's one we've updated based on an RAI response.

And, in particular, these -- these wind speeds are much lower than the tornado wind speeds, so they're -- they're not likely to be limiting parameters, but the -- we've included them and consider them.

For ambient design temperatures, we looked at several sources. We started out with the upper utility requirements document for getting the values for 2 percent, 1 percent, and 0 percent exceedance, and then we also looked at the ESP applications from North Anna, Grand Gulf, and Clinton, and we've picked a bounding set of parameters from all those documents as our basis for the ESBWR design.

They may not bound every site in the country, every potential site in the country, but they bound at least -- we think they bound the sites that are most likely to put plants up in the near term.

For tornadoes, we have used a maximum tornado wind speed of 147 meters per second or 330 miles per hour. This is actually slightly higher than the value that eventually ended up in the latest version of Reg. Guide 1.76. At the time we had to select a value, there was an NRC interim position on Reg. Guide 1.76 that recommended this value. And it has subsequently been lowered to 300 in the final issued reg. guide, but we stuck with the 330 for our design purposes. And in conjunction with that, there is a maximum rotational speed of 260 miles per hour.

For Category 1 buildings, we have

established maximum settlement values for the reactor building and fuel building in combination, which share a common basemat, and then separately for the control building. These values are based on stresses the basemat can accommodate during movement, and those values came out of the seismic analyses from Chapter 3.

The soil properties are, again, mostly out of the seismic analyses from Chapter 3. We have defined minimum static bearing capacities for the seismic wind structures. We have used a minimum shear wave velocity of 300 meters per second, or 1,000 feet per second. And we have assumed no liquefaction potential underneath the footprint of the seismic Category 1 and Category 2 structures, based on site-specific safe shutdown earthquake.

We also have included a parameter for the angle of internal friction for the seismic analysis that is greater than or equal to 30 degrees, and we have looked at both settlements and differential settlements across the basemat.

In the area of seismology, for ground response spectra we have -- we have specified a horizontal and vertical ground response spectra.

Those, for the low frequencies, up to about 9 to 10 Hertz, are taken from Reg. Guide 1.60. Above that point we have used the North Anna ESP values for those parameters.

For hazards in the site vicinity, the main thing we have looked at there is probability of impacts --

MEMBER POWERS: That's kind of remarkable, I think, that you use North Anna, because the high frequency depends on how close you are to the seismic source, doesn't it? I mean, that's where it dissipates the quickest, so the closer you are to a source --

MR. HAMON: Well, North Anna had some fairly high numbers in that range. That's why we -- why we picked it. They were actually higher than the ones in the reg. guide, and --

CHAIRMAN CORRADINI: So you didn't -- I thought you were -- I just assumed you picked them because they're the likely first --

MR. HAMON: No. We actually looked at the various sites and what their characteristics were. We were trying to make sure we bounded --

CHAIRMAN CORRADINI: Okay.

MR. HAMON: -- came up with some bounding conditions for all of the sites, and North Anna had some high frequency ones that were more severe than elsewhere.

And, again, when we get to Chapter 3, if you want to go into what -- we'll have some experts here that are more familiar with the details of how they came up with that. But that was basically --

MEMBER POWERS: An item of curiosity would be how you thought you would interface with this new civil engineering standard for seismic design.

MR. HAMON: Which standard is that that's --

MEMBER POWERS: ASCE -- to quote you the number of the standard. It was sort of the one that Clinton used for their early site permit.

MR. HAMON: The ASCE 7-02 or --

MEMBER POWERS: That sounds --

MR. HAMON: That one -- I might have to doublecheck that one. I'm not sure off the top of my head.

MR. MUNSON: Yes. I'm Cliff Munson of NRR. The standard you're referring to is ASCE 43-05. And it's -- it's determined by the -- it would be determined by the COL or the ESP applicant, so it doesn't really involve -- it's to determine the site hazard, not the design ground motion, which is what we're doing here. So --

MEMBER POWERS: And that's why I'm just interested in how you thought you would interface with that.

MR. HAMON: Well, like I say, we --

MR. MUNSON: Just for example, the North Anna ESP is the high frequency portion of that design, which I have a graph of I'll show in my presentation. That's a site hazard calculation for the ground motion. So they combined a design, Reg. Guide 1.60 spectrum, plus the North Anna site to make up their total design SSE.

MR. HAMON: Okay? Okay. And the next area we looked at was hazards in the site vicinity, was primarily concerned looking at probabilities for impacts from missiles or aircraft. And then, for the standard plant we didn't postulate any specific volcanic activity or toxic gases in the area or sources of toxic gas in the area, but that's something the individual COL applicants would have to look at and address if there are any potential impacts from that.

MEMBER POWERS: Did you look at the issue of blast waves?

MR. HAMON: What was that?

MEMBER POWERS: Did you look at the issue of blast waves?

MR. HAMON: Blast waves.

MEMBER POWERS: What I'm thinking in terms of is explosions, say, on the Mississippi River that affect Grand Gulf, or something like that.

MR. HAMON: I'm not sure if we did or not. Do you know, Pete?

MR. JORDAN: No, I don't.

MR. HAMON: I don't remember if we did that.

MR. JORDAN: I haven't seen anything that I recall that addresses that.

MR. HAMON: Yes. I mean, if we did, it would have been buried into saying it was bounded by one of these wind conditions, but I don't know for sure on that. We'll have to doublecheck that one.

MEMBER STETKAR: You said you used probabilistic criteria. Was there -- I seem to recall reading somewhere that there was essentially a screening frequency of 10^{-7} event per year. Is that correct?

MR. HAMON: Yes. It's actually -- there's one of the reg. guides or SRPs that has a -- says approximately 10^{-7}.

MEMBER STETKAR: How do you reconcile that with the fact that the entire core damage frequency in a PRA from theoretically everything that's analyzed is an order of magnitude lower than things you might be throwing away?

MR. HAMON: Would you like to take that one, Rick?

MR. WACKOWIAK: In the PRA section, we have looked at a couple of these other things like the aircraft and some other facility incidents.

MEMBER STETKAR: Military aircraft?

MR. WACKOWIAK: No. That's outside the -- our scope right now. We have looked at a couple of those things and shown that -- that those types of things don't bring in any new risk-significant things or any -- any new insights to what we have in the CDF and are not major contributors.

So we've looked at it independently of what they're doing to see if, you know, it -- you don't just have the aircraft impact and then say it's core damage. Other things have to happen. So a 10^{-7} type initiator, if we have some defense in depth remaining, then it shouldn't be an influence on the CDF.

MEMBER STETKAR: Is it correct to interpret what you've said is that you've gone through some type of external hazards screening process that's different from the hazards screening that they may have -- that your group may have done for --

MR. WACKOWIAK: I don't know that they did hazards screening. They had hazards characteristics for the site.

MEMBER STETKAR: Well, but they've not looked at anything that they've judged to be lower in frequency than 10^{-7} event per year.

MR. WACKOWIAK: Right.

MEMBER STETKAR: So they haven't practiced -- I guess thought about that. A large asteroid comes to mind, for example. That might have, quite conceivably, a frequency of higher than 10^{-7}, maybe not higher than 10^{-7} per year, but perhaps measurable compared to 10^{-8} per year.

MR. WACKOWIAK: Yes, that would be a

problem.

MEMBER STETKAR: The sum total of -- okay.

MR. HAMON: The estimate is more like 10^{-9} for that, but I don't know -- for hitting a specific spot anyway.

MEMBER STETKAR: Yes, right. Okay.

MR. WACKOWIAK: So I guess just to summarize, what we tried to do was look back at some of these things and say, "Do we still have remaining capability with that?" And if we did, yes, that initiator is much lower than the other initiators that we have already looked at in the PRA. And we judge that we weren't going to get any new insights from that.

MEMBER STETKAR: You couldn't identify any more severe consequences.

MR. WACKOWIAK: Right.

MR. HAMON: Okay. Thanks, Rick.

Okay. We also included in the table in Chapter 2 a line item called required stability of slopes. This really isn't a design parameter or a site parameter. It's really more of a design criteria that's required to use in the analyses, and we just didn't have any -- didn't see any other better place to stick it in the DCD. So it was included in Chapter 2.

And then, we also have in the tables in Chapter 2, meteorological dispersion, chi over Q values that come from our short-term atmospheric dispersion estimates that are in Chapter 15 of the DCD for the accident analyses, and also from the long-term dispersion estimates for routine releases that are addressed in Chapter 12 of the DCD.

MR. KRESS: The chi over Q as a measure of wind and meteorological properties of a site, did you actually go to various sites or get the data from various sites?

MR. HAMON: We actually looked at data from a variety of sites in trying to come up with those numbers, yes, to --

MR. KRESS: Do your numbers bound those sites, or what do they -- are they sort of in the middle?

MR. HAMON: We've tended to pick bounding numbers. I believe the numbers we have will bound the North Anna application and the Grand Gulf application and --

MR. KRESS: Why do you think those would

be representative of the sites?

MR. HAMON: Well, I'm not sure exactly how many different sites we looked at, and in about three weeks the Chapter 12 discussions are going to be here -- they can provide you some more details on how they came up with them specifically. Yes, I -- like I say, this chapter has so many different areas in it that I'm --

MR. KRESS: It turns out to be -- I mean, you can choose whatever you want to do. It's a COL item, so --

MR. HAMON: Yes.

MR. KRESS: -- it doesn't really matter much.

MR. HAMON: And if -- again, if on an individual site basis you weren't bounded by these numbers, you'd just have to address what's the impact on the analysis and update the analysis, so --

MR. KRESS: So it's really not a design certification problem. It's --

MR. HAMON: We did at least look at several different ones and try to bound a --

MR. KRESS: That probably wouldn't exclude too many sites.

MR. HARVEY: This is Brad Harvey with the staff. I'm going to cover a little bit of that in my presentation to follow. If you ask me a question then, I might have more information to give you.

MR. KRESS: Okay. Thanks.

MR. HINDS: Additionally -- yes, this is David Hinds from GEH. In the dose calculation discussion that we'll have when we get to -- through Chapter 15, we'll also speak to the chi over Q values there. But one of the methodologies there is the determination of an acceptable range of chi over Qs, given the consequences of the Chapter 15 LOCA analysis. But we'll discuss that in detail with our Chapter 15 analysis as well. But it determined a bounding chi over Q for the dose calcs for LOCA analysis.

MR. HAMON: Okay. Moving on to applicable references, we based our Chapter 2 on the standard review plan as it existed as of February 2005, which was six months in advance of our submittal of the original version of the DCD. We have also used the American Society of Civil Engineers, ASCE 7-02, Code as a basis for some of this information.

As we mentioned earlier, we have referred to some National Weather Service publications on hydrometeorology for rainfall and snow loads. We have used the EPRI Advanced Light Water Reactor Utility Requirements document as a source for a number of these parameters or as a reference to help assist in determining the parameters. And then, for the tornado wind speed, one reference for that is SECY 04-0200, which is -- describes the NRC interim position that defined the 330 mile an hour tornado speed.

Okay. And in summary, basically, we believe Chapter 2 provides a sound description of the ESBWR standard plant site design parameters that we have used in our various analyses. The actual site characteristics will be included in the individual COL applications or ESP applications, and GEH is continuing to work with the NRC to address the few remaining open items that we still have on this chapter.

Any other questions?

(No response.)

CHAIRMAN CORRADINI: Thank you very much.

MR. HAMON: Okay.

MS. JOHNSON: Good afternoon. My name is Andrea Johnson. I'm the Project Manager in New

Reactor Licensing, and we're going to be going through the staff review of Chapter 2. It's going to be very similar to the presentation that Ilka gave earlier this morning.

Our review team consisted of myself as the PM, and with me this afternoon we have Fred Harvey, Ken See, Cliff Munson, and we also had significant input by other staff as well, such as Rao Tammara and Goutam Bagchi, who are also here with us.

We're going to go through the applicable regulations, the status of the RAIs, some of the technical topics, open items, COL action items, and then we're going to be having the discussion that comes from that.

This is a high-level summary of the applicable regulations that were used in the review. A more detailed listing of the regulations are actually in the safety evaluation itself, in the GDCs, as well as the SRPs, reg. guides, branch technical positions, and so forth, as appropriate.

We originally had 54 RAIs in Chapter 2, and 50 of those have been resolved, with four still remaining open. And those will be discussed later on in the presentation by Brad.

Just a couple of points that we wanted to bring up regarding Chapter 2, because it is somewhat unique compared to some of the other chapters. Some of this has already been discussed earlier by GEH. Design certification applicant provides postulated site parameters for the design and evaluation of the design in terms of such parameters.

Tier 1 and Tier 2 of the DCD define the envelope of site-related parameters that the ESBWR standard plan is designed to accommodate. The list of the ESBWR site envelope design parameters are given in Tier 2, Table 2.0-1, which is toward the end of that chapter.

The specified safe parameters are the top-level down insight parameters used to define a suitable site for a facility referencing the certified design. The few applicants referencing a certified design are required to demonstrate compliance with the site parameters. DCD, Chapter 2, defers a majority of the siting issues -- and, therefore, the staff review -- to the COL stage.

I'm now going to turn this over to Brad, who will be going through the next several sections of the chapter.

MR. HARVEY: Hello. My name is Brad Harvey. I'm a Senior Meteorologist with NRO. I'll be discussing the following topics related to the staff's review of the ESBWR design control document. SER Section 2.1, which is geography and demography; Section 2.2, nearby industrial, transportation, and military facilities; and Section 2.3, meteorology.

Section 2.1, geography and demography, typically involve site-specific information such as site description and location, exclusionary authority and control, and population distribution. The ESBWR states that the COL applicant is to provide this information as part of the COL application. The staff finds this acceptable.

SER Section 2.2, nearby industrial, transportation, and military facilities, typically involve site-specific information such as the identification of potential hazards in the site vicinity and the evaluation of potential accidents.

The ESBWR DCD states that the COL applicant is to provide this information as part of the COL application. The staff finds this acceptable. Note that the applicant has not classified any potential accidents in the vicinity of the plant as design basis events.

MEMBER POWERS: But as part of the design certification, it seems to me that we need to assure ourselves that the design is not particularly vulnerable to the intake of noxious gases into the control room or susceptible to damage -- easy damage by blast waves and things like that as the result of transportation accidents.

MR. HARVEY: That's correct. So that would be evaluated on the hazards that are at a given site at the time the COL application comes in. Those hazards would be identified, and, if necessary, the design would need to be modified to address those hazards.

CHAIRMAN CORRADINI: So there is no minimum standard I guess is what Dana is asking?

MR. HARVEY: Well, the minimum standard is that, I mean, for the design itself, no. To handle that type of accidents, no.

CHAIRMAN CORRADINI: So you leave it to the site. So, for example, if I put this plant near oil refining facilities somewhere in Texas, I'd have to worry about those specific things, and there's no minimum by which, no matter where I stick it --

MR. HARVEY: Yes. Well, I believe that toxic material issues are not a concern for most current operating plants.

MEMBER POWERS: I think they are a concern for every single current operating plant.

MR. HARVEY: Not while --

MEMBER POWERS: Do all plants have chlorine tanks or something like that near them?

MR. HARVEY: Have what? Excuse me.

MEMBER POWERS: Chlorine tanks. For instance --

MEMBER MAYNARD: It's less now than what it used to be I guess.

MR. HARVEY: And, again, if that's part of the design of the plant, that would be needed to be added -- considered at the time that the site is chosen and the plant.

MEMBER MAYNARD: I'd like to ask GEH, do you have in the AC system the ability to isolate the control room and the --

MR. HINDS: This is David Hinds of GEH. We have a control room habitability system that, yes, has an ability to isolate the control room.

MR. HARVEY: But what they would need to

do, if toxic gas was a concern, is they would have to have toxic gas monitors most likely, which is not part of the standard design.

MEMBER MAYNARD: Yes, and that could change site to site, depending on what they have, what the gas monitors would be and what the isolation signal would be. I am a little surprised that the standard design requirements are such -- at least have the ability to -- that could be done with the COL.

MR. HARVEY: Maybe the better question is, when that particular section of the SER comes up, to ask the control room habitability people that.

MS. CUBBAGE: Right. Brad, I was going to suggest the same thing, that our reviewers in the control room habitability area have had questions along this line, and I'm sure they'd be happy to talk more about this when they come.

And I believe -- I'm not positive is this is a Chapter 6 or 9 issue, because there's a lot of overlap there. But Chapter 9 we're targeting for November Subcommittee.

CHAIRMAN CORRADINI: Just to be clear -- I just want to make sure I understand, just to be clear that with the -- with the way the chapter -- or the way the analysis is done now, it really -- it really can't be decided it's appropriate at any site, because there is no nominal, typical, generic site that was looked at with it.

MR. HARVEY: For this particular aspect of siting, that's correct.

MEMBER STETKAR: I raise the issue that I -- recognizing the potential sensitivity of aircraft crash events, either commercial or military, that seems to be an area where -- recognize that at a specific site I might be able to install some protections against blasts or some additional sensing for noxious gases and things like that, because that's relatively inexpensive.

I can't really redesign the containment or some of the other structures. So the question arises in my mind regarding the screening -- numerical screening criteria and how those relate to your evaluation of a particular design. Given the fact that GEH has structures in place with -- they aren't going to redesign those on a site-specific basis.

How do they address issues of things like aircraft crashes, capability to withstand aircraft crashes?

MR. HARVEY: I don't have --

MEMBER STETKAR: They might occur more frequently than once every 10 million years.

MR. HARVEY: I can't speak from experience for the staff, because that's not an area that I've spent a lot of time with -- any time with.

MEMBER MAYNARD: I believe we're going to deal with some of that and some security and safety -- i don't think that's probably a good topic for this --

MR. HARVEY: What I will point out is that the design will withstand tornado wind speeds up to 330 miles an hour, and that will bound I think a lot of the other concerns that you might have.

CHAIRMAN CORRADINI: Let me turn to the back bench, Amy.

MS. CUBBAGE: I'm sorry.

CHAIRMAN CORRADINI: Do you have any guidance for us as to when we might hear about that, so we can defer this to an appropriate time?

MS. CUBBAGE: Right. Well, if you're speaking to proximity to airports and accidental aircraft, I think what we're seeing is there's a certain probability that's assumed for those types of hazards, and then other issues would need to be discussed in a security-related discussion, which we are targeting our first interactions with you on that in November.

But there's a lot of work to be done in that area as an agency with guidance and regulations at this point. So we probably won't have a definitive --

CHAIRMAN CORRADINI: Okay. That's fine.

MS. CUBBAGE: -- position on that.

CHAIRMAN CORRADINI: But to go back to your first category, that then is still site-specific. That is wherever the site is, and I might have non-commercial private aircraft. Then, it depends on where it is relative to those facilities.

MS. CUBBAGE: Right. And that definitely speaks to the site suitability rather than a design issue, but there is certainly structural robustness built into this plant, as Brad indicated, to handle certain external events.

CHAIRMAN CORRADINI: Okay.

MR. HARVEY: SER Section 2.3, meteorology, typically involves site-specific information such as regional climatology, local meteorology, onsite meteorological measurements program, short-term atmospheric dispersion estimates for accidental releases, and long-term dispersion estimates for routine releases.

The ESBWR DCD states that the COL applicant is to provide this information as part of the COL application. The staff finds this acceptable.

Meteorological site parameters. Table 2.0-1 of the ESBWR DCD identifies climatic and atmospheric dispersion site parameters. These site parameters are the postulated meteorological features assumed for the site, which the applicant used to design its facility. The climatic site parameters were selected to ensure the facility is being decided such that the potential threats from the physical characteristics of a potential site, such as regional climatic extremes and severe weather, will not pose an undue risk to the facility.

Accident atmospheric dispersion site parameters were selected to help demonstrate that the radiological consequences of accidents offsite and in the control room meet radiation dose criteria specified in 10 CFR 52.46 and GDC-19.

MR. KRESS: Are those the same as what used to be in 10 CFR 100?

MR. HARVEY: Yes. To my knowledge, yes.

MR. KRESS: So they are not for severe accidents.

MR. HARVEY: That's correct. Design basis accidents.

Routine release atmospheric dispersion site parameters were selected to help demonstrate that calculated offsite concentrations and dose consequences of routinely airborne radioactive releases meet criteria specified in 10 CFR Part 20 and Appendix I to 10 CFR Part 50.

A COL applicant needs to demonstrate that its meteorological site characteristics fall within the ESBWR meteorological site parameters. Should the meteorological site characteristics not fall within the ESBWR meteorological site parameters, the COL applicant must provide supporting justification, through an exemption or amendment, that the proposed facility is acceptable at the proposed site.

The staff attempted to evaluate the ESBWR meteorological site parameters to ensure they are representative of a reasonable number of sites that may be considered within a COL application. In some --

MR. KRESS: How did you do that?

MR. HARVEY: In some cases -- and I'll go through parameter by parameter how we did that -- in some of the cases the staff accomplished this by comparing the meteorological site characteristics from the Clinton, Grand Gulf, and North Anna early site permits, with the corresponding meteorological site parameters listed in the ESBWR DCD.

MR. KRESS: That leaves me wondering why I think those three sites are representative of a reasonable number of sites.

MR. HARVEY: Geographically, they're fairly dispersed -- one being in Illinois, the second one being in Virginia, and the third being in Mississippi.

MR. KRESS: See, the one in Illinois is about 120 miles from Chicago?

MR. HARVEY: It's the center of the state.

MR. KRESS: And the one in Virginia is about 100 miles from where we are here?

MR. HARVEY: That's correct.

MR. KRESS: I don't know if I'd -- do we worry about 100-mile distances in -- when we do site suitability type --

MEMBER STETKAR: Oh, yes.

MR. KRESS: I'm just wondering, you know, it probably doesn't matter because the sites you choose is going to have to -- to, you know, show that it meets the right criteria, the dose criteria. But I was just wondering why you thought these were enough sites to make it representative of a reasonable number of sites. Is there something special about their populations and population distributions that --

MR. HARVEY: Actually, the population -- well, I'm looking more at the climatology.

MR. KRESS: Oh.

MR. HARVEY: I'm strictly -- I'm looking at just meteorology and not --

MR. KRESS: It might very well be reasonably representative.

MR. HARVEY: I apologize, it's meteorology. I'm discussing Section 2.3, limiting my discussion to meteorology.

MS. CUBBAGE: Right. To some extent, it's a business decision on the part of a design certification vendor -- I mean, a design vendor. If they were to choose more extreme conditions to bound every possible site in the United States, they would be free to do that. But that's not required.

MEMBER STETKAR: Yes. One --

MS. CUBBAGE: And as you indicated, it would be required at the COL stage to verify that the site is suitable in light of the design, or they would have to justify any deviations.

MEMBER STETKAR: One question. It happens to be in Section 2.3, but -- and it's under the control room evaluation part of that section. I noticed that the release -- potential releases from the reactor building that might impact the control room included what I'd characterize as basic bulk releases into the reactor building, with the exception of a LOCA -- the normal leakage through the PCCS during a LOCA event.

Did anyone evaluate a direct release through a breach in the isolation condenser? Because that's something that -- an isolated break from the isolation condenser.

MR. HARVEY: I'm not sure. This is one of the open items that we currently have with the applicant to have them clearly identify all of the release -- all the accidents and the release pathways to the environment resulting from each accident.

MEMBER STETKAR: I understand. Thank you.

MR. HINDS: Excuse me. This is David Hinds from GEH. One point, if I could add on the -- you asked about isolation condensers. We have an automatic isolation feature with radiation detectors that isolate that source if detected radiation.

Thank you.

MR. HARVEY: May I have the next slide, I guess.

Climate site parameters. The ESBWR DCD presents climatic site parameters related to extreme wind, tornadoes, precipitation for roof design, and ambient design temperature.

Extreme wind site parameters. The staff reviewed the applicant's extreme wind site parameters by comparing them to wind loading design criteria presented in ASCE 7-02, which is the American Society of Civil Engineers standard for the minimum design loads for buildings and other structures.

The staff found that the ESBWR extreme wind site parameters meet the ASCE 7-02 wind loading design criteria except for along in the hurricane-prone Gulf, Georgia, South Carolina, and North Carolina coasts, as well as Southern Florida.

Consequently, the staff concluded that the applicant's extreme wind site parameters are representative of a reasonable number of sites that may be considered within a COL application. The staff finds this acceptable.

MEMBER POWERS: Again, you've referred to a standard that was written at some period of time. Now we have people telling me -- telling us that the climate of the past may not be the climate of the future. How do you react to that?

MR. HARVEY: Several things. Along -- the ASCE standard does take hurricane frequencies into consideration, which is why the design basis criteria for coastal sites, the wind speed is higher than it is for most of the rest of the United States.

The design criteria presented in the ASCE standard is based on a paper presented in the Journal of Structural Engineering by Peter Vickery and Larry Twinsdale, the October 2000 issue. And I actually had a conversation with both of those gentlemen earlier this year, and asked them specific questions concerning the scientific debate that's going on about potential increase in intensity and frequency of hurricanes.

And regardless of what you read in the mass media, there is not total consensus among --

MEMBER POWERS: You don't have to go to the mass media to see there's not total consensus.

MR. HARVEY: But I asked these gentlemen specifically what they know now, based on the work that they did 10 years ago, almost 10 years ago, and they said, actually, based on improved modeling techniques that they would use is that they would see the wind speeds actually would decrease, not increase.

They apparently are of the cap where they're not totally convinced that there is going to be a significant increase in frequency or intensity of hurricanes, but there is enough conservatism already in their methodology. And as they improve the methodology as it goes along, it's robust for the time being.

MEMBER SIEBER: That may be a political question rather than a technical one.

MEMBER POWERS: It seems to me that the issue of cycles in hurricane frequency is incontrovertible, that certainly on the Atlantic coast the data are -- are pretty conclusive on that. What's not conclusive is whether the intensity of whether you get these magnitude 5 or 4 -- frequency of magnitude 5 and 4 hurricanes changes in parallel with the change in frequency. You know, that's --

MR. HARVEY: That was a pointed question that we had asked these --

MEMBER POWERS: Reasonable men disagree on this, and --

MR. HARVEY: Yes.

MEMBER POWERS: -- we're not -- I certainly am not in a position to judge between this expertise. You may be able to, and they may be able to, but they have this scientific debate. How do you -- I mean, how does the agency react to that? Does it say, okay, we'll take the -- the most conservative position, the least conservative position, halfway in between?

MR. HARVEY: That's a good question. We had a discussion in the -- with the fact that there's -- to put additional margin on the applicant. Given the uncertainty with the calculation, that doesn't seem particularly fair in this -- in this case. So what we're doing is watching the debate in the papers as they -- as they come out.

MEMBER POWERS: I mean, it's not a debate that needs to be resolved for this sort of occasion, because, you know, they've taken a set -- and if the COL applicant comes in and says, "I'm going to use their set," and we don't find it applicable to the site, he's got to do something about it. But it's not clear to me how you go about deciding that.

MR. HARVEY: The other thing I might offer is that I think the -- I've been told anyway that it's actually a tornado that bounds the design of the plant and not these extreme winds.

MEMBER POWERS: They could, but the problem with hurricanes is they spawn tornadoes.

MR. HARVEY: But usually not very strong ones.

MEMBER POWERS: That may be.

MR. HARVEY: Any other questions?

MEMBER STETKAR: It gets you around the roof loadings and that kind of stuff. We have to look at each one separately.

MR. HARVEY: Tornado site parameters. The staff reviewed the applicant's tornado site parameters by comparing them to design basis tornado characteristics specified in Revision 1 to Reg. Guide 1.76. The staff found that all of the tornado site parameters selected by the applicant are more severe than the Region 1 design basis tornado characteristics specified in Reg. Guide 1.76, where Region 1 represents the central portion of the United States where the most severe tornadoes typically occur. The staff finds this acceptable.

Precipitation site parameters for roof design. The applicant chose roof design site parameters, which include a 100-year maximum ground snow load and a maximum 48-hour winter rainfall. The staff reviewed the applicant's 100-year maximum ground snow load site parameter by comparing it with the 100-year snow pack site characteristics identified in the Clinton, Grand Gulf, and North Anna early site permits.

The staff found that the applicant's maximum ground snow load site parameters or slight -- site parameter is more conservative than the three ESP 100-year snow pack site characteristics. Consequently, the staff concluded that the applicant's 100-year maximum ground snow load site parameter is representative of a reasonable number of sites that may be considered within a COL application. The staff finds this acceptable.

MEMBER POWERS: One would be surprised if they didn't bound the 100-year snowfall of Grand Gulf all right.

(Laughter.)

MEMBER BLEY: Have you folks thought about whether there could be any correlation between the snow pack and rain? I don't know if I'm just unlucky, but I've seen a lot of cases where not long after major snow rain comes and washes away, which increases the weight loading tremendously. Have you either looked at the combination or convinced yourself that the likelihood of it is very low?

MR. HARVEY: The second half of this bullet will I think sort of address that.

MEMBER BLEY: Okay.

MR. HARVEY: The staff actually identified an open item when it reviewed the applicant's maximum 48-hour winter rainfall site parameter. To give you a little background, the standard review plan suggests that the normal live loads on roofs should include the weight of the 100-year snow pack.

And then, the extreme live load should be based on the addition of the 100-year snow pack plus the weight of the 48-hour probable maximum winter precipitation at ground level. Okay? And some of that can be rain, some of it can be snow or ice. And, in fact, the open item I'm about to discuss goes into that in a little detail here.

The applicant states that it's a maximum 48-hour winter rainfall, and they only present it in terms of rainfall, site parameter of 36 inches would result in an additional weight of only four inches of water on the roof, because the lower lip of the roof scuppers is four inches above the roof.

However, the staff believes the applicant should also provide an additional roof design site parameter to account for additional weight, if at least part of a maximum 48-hour winter rainfall falls as frozen precipitation, such as snow and/or ice, and, therefore, remain on the roof. So you're talking about the 100-year snow pack, plus some additional frozen precipitation that would remain above that. So this is open item 2.3-4.

Ambient temperature site parameters. The staff reviewed the applicant's ambient temperature site parameters by comparing them with the ambient temperature and humidity site characteristics identified in the Clinton, Grand Gulf, and North Anna early site permits.

The staff found that the applicant's ambient temperature site parameters bound the corresponding site characteristics for the three ESP sites. The staff found that acceptable.

Atmospheric dispersion site parameters. The ESBWR DCD presents atmospheric dispersion or chi over Q site parameters related to both short-term accident releases and long-term routine releases.

Accident release chi over Q site parameters. The applicant identified accident atmospheric dispersion site parameters which are used in its accident radiologic consequence analysis presented in DCD Tier 2, Chapter 15. These included chi over Q values for releases to exclusionary boundary, out of boundary of the low population zone, and control room.

The EAB and LPZ chi over Q values are used to help demonstrate that the offsite radiological consequences of accidents meet specified radiation dose criteria, as specified in 10 CFR 52.47, and the control room chi over Q values are used to help demonstrate that the radiological consequences of accidents meet specified radiation dose guidelines in the control room as specified in GDC-19.

MR. KRESS: Those D over Q values, did they include some estimate of the effects of rainfall?

MR. HARVEY: D over Qs are used for routine releases, not the accidents. And no is the answer to your question.

MR. KRESS: Oh, they didn't. I'm thinking severe accidents again, yes.

MR. HARVEY: Severe accidents, I can't -- that's my -- not my area.

To answer your question, as far as I know, the answer is yes for severe accidents, but I know very little, you know, detail on that.

EAB and LPZ chi over Q site parameters. The staff reviewed the applicant's EAB and LPZ chi over Q site parameters by comparing them to the corresponding site characteristics identified in the Clinton, Grand Gulf, and North Anna early site permits.

The staff found that the applicant's EAB and LPZ chi over Q site parameters bound the corresponding site characteristics for these three ESP sites. Therefore, consequently, the staff finds that the applicant's EAB and LPZ chi over Q site parameters are most likely representative of a reasonable number of sites that may be considered within the COL application. The staff finds this acceptable.

MEMBER SIEBER: When you review a specific site, particularly one that is in hilly country, do you take into account the variations of chi over Q that are caused by hills and valleys?

MR. HARVEY: Yes.

MEMBER SIEBER: And how do you do that?

MR. HARVEY: That would probably show in your --

MEMBER SIEBER: On the MIDAS code or something like that? I know that --

MR. HARVEY: Well, we have our own -- are you talking about design basis accident parameters? We have a version of MIDAS that's the same thing called PAVAN. And you would look at --

MEMBER SIEBER: You actually do take topography into account when you --

MR. HARVEY: It's actually more --

MEMBER SIEBER: -- determine suitability.

MR. HARVEY: Yes.

MEMBER SIEBER: Okay. I think that's important, because the differences between valley radiation dose where most people live, and hilltop radiation dose is a factor of two, factor of three sometimes.

MR. HARVEY: Probably not even that accurate.

MR. KRESS: Normally, they just measure elapsed rate and wind speeds.

MR. HARVEY: But the wind direction frequency would --

MR. KRESS: Wind direction may be affected. It's measured right there at the site boundary, and, you know, it -- 10 miles down it may be going the other direction, and they won't get that.

MEMBER SIEBER: If you get up into the synoptic winds, then you can look at the mass transfer of air as guiding what the concentration would be. If you take a plant that is built on a river with valleys on both sides, and streams, and so forth, it will concentrate in that valley before it gets --

MR. HARVEY: Well, the wind direction frequencies -- the wind --

MR. KRESS: It probably might capture that.

MR. HARVEY: You would capture that in the wind direction frequency.

MR. KRESS: But it wouldn't capture a meandering wind.

MEMBER SIEBER: Yes.

MR. KRESS: Because, you know, what they do is they measure the probability of wind at a given sector direction over a year's time, and get a probability. And, you know, that really doesn't deal with meanderings, plumes, and the site characteristics very well. But, you know, as a risk estimator, or as a way to see if you can meet the regulatory requirements, it's perfectly all right I think.

MEMBER SIEBER: There are tools out there that licensees can use, or potential licensees, and then there are ways to estimate that. And one way is just to say that a given site has a certain proportion of hills, and the ratio between the tops of the hills and the synoptic winds is such and such, and you add a factor on it.

That's sort of arbitrary. I'm satisfied that you understand what I'm talking about and do have the tools to do it. But sometimes when you get plants built in valleys you need to pay attention to that.

MR. HARVEY: I agree with you.

MR. KRESS: Well, you know, it's good things to pay attention to if you're figuring out emergency response.

MR. HARVEY: Yes.

MR. KRESS: But I don't think it may -- it may not be necessary to see if you meet these regulatory criteria.

MEMBER SIEBER: You may be right. I'll concede that.

MR. HARVEY: The staff did identify an open item when it reviewed the applicant's description of the accident dose consequence analysis presented in DCD Tier 2, Chapter 15. The staff found that the applicant used a chi over Q value lower than the EAB chi over Q site parameter to calculate doses at the EAB for two of its Chapter 15 accidents.

The use of a lower chi over Q results in lower calculated doses for the EAB for these two accidents. The staff has asked the applicant to explain why a lower chi over Q value was used for these two accidents. This is open item 2.3-8.

Control room chi over Q site parameters. The staff identified an open item when it reviewed the applicant's control room chi over Q values. The staff reviewed the applicant's control room chi over Q values to ensure that the assumed fission product transport to the environment for each analyzed event was compatible with the chi over Q values used to model the release pathway.

The staff also asked the applicant to provide details concerning the distances and directions between each potential accident release pathway and each air intake and in-leakage pathway to the control room. This information will be needed by each COL applicant in developing site-specific control room chi over Q values.

The applicant is still compiling this information in response to the staff's request for additional information. This is open item 2.3-9.

MEMBER STETKAR: May I ask -- I'll ask the question again, but I'm not sure -- I'll probably get the same answer. Is one of those potential accidents a release from an unisolated ruptured isolation condenser? That's probably a question to --

MR. HARVEY: Yes, it's beyond me.

MEMBER STETKAR: Okay.

MR. HINDS: Again, this is David Hinds for GEH. Again, we've -- we have the isolation feature that we are reliant upon, and so, therefore, did not count on a continued release through an isolation condenser as a release path.

MEMBER SIEBER: Well, it wouldn't show up in your risk analysis, because it doesn't result in a CDF or LRF. That was just a -- just a relief.

MEMBER STETKAR: No, it would. It's a direct -- if the steam supply to the isolation condenser is not isolated, and the isolation condenser is ruptured, the infiltration through the pool -- but that's it. I mean, it's -- it goes out the roof.

MS. CUBBAGE: Are you postulating core damage at this point, or just normal --

MEMBER STETKAR: Yes. I mean, you know --

MS. CUBBAGE: So you're --

MEMBER STETKAR: -- I'm sure there are accident scenarios that could be initiated by --

MS. CUBBAGE: Well, in a design basis space, they don't -- they're not melting the core, so I think you're in a severe accident type of scenario.

MEMBER STETKAR: Okay.

MS. CUBBAGE: Rick has left, I believe.

MEMBER STETKAR: I'm not as familiar with that. I'm personally not as familiar with that side of the accounting ledger, so that's --

MS. CUBBAGE: I understand. Understand.

MEMBER POWERS: Well, design basis space, they're going to vent all the fuel vents, which is balloons and ruptures, so you get roughly five percent of the inventory of noble gases and iodine out --

MS. CUBBAGE: So you're speaking of the design basis dose calculation. Right. And I believe that Jay Lee has asked questions about that pathway, and I -- it has been many, many months, so I don't have the details, but we might be able to talk about that when we come back with Chapter 6.

MS. CUBBAGE: But I know there was discussion about the fact that the release path would be within a pool, and then it goes out through a moisture separator, and there was discussion of detection capability.

MR. KRESS: Isn't the containment normally considered intact with those calculations?

MS. CUBBAGE: Well, the release path, if it went out through the -- a broken isolation condenser, it would be outside containment. I'm sorry?

MR. KRESS: Isn't that a failure of

containment? Normally, you just use the containment normal leak rate I think.

MR. HINDS: This is David Hinds from GEH. You're correct that we use the containment leakage rate. Assuming a source term and use containment leakage rate, as opposed to assuming that it's a point source from an isolation condenser, is an example. And, again, we will cover in detail in our LOCA dose calc, Chapter 15 --

MR. KRESS: This other thing you will cover in your PRA as a part of -- part of the PRA type analysis, which --

MEMBER SHACK: Well, no. I mean, if the isolation condenser wasn't isolated, it would look like a steam tube rupture --

MR. KRESS: Which is a severe accident.

MEMBER SHACK: -- outside. That's a design basis accident.

CHAIRMAN CORRADINI: A steam tube rupture is a design basis accident, Tom, isn't it?

MEMBER SHACK: Yes, no core melt. I mean, you just call -- as Dana says, you get a release. It's not a core melt release, but it's a release. But, again, it's -- it's through a pool, and it's isolated. I'm not sure exactly how that's handled.

MR. HINDS: I think you're probably comparing it to a high energy line break. It's -- so, yes, we have high energy line break analysis, we have LOCA dose calcs. But the LOCA dose calcs were done with the methodology discussed before of the assumed total containment leakage rate, or designed total containment leakage rate.

MEMBER POWERS: Roughly speaking, it only takes about 24,000 curies of iodine to violate the Part 100, and that's -- 24,000 curies of iodine is trivial. I mean, three-quarters of a billion curies of -- I only get one-third of it anyway.

MR. HARVEY: I just noticed, by the way, on the presentations that the chi came out I guess as an epsilon there. I apologize. I think it's correct -- it's right on the hard copy, but a different version of --

MEMBER POWERS: It's all Greek to us.

(Laughter.)

MR. HARVEY: Routine releases. The ESBWR DCD identifies routine release atmospheric dispersion site parameters, which are used in DCD Tier 2, Chapter 12, to calculate offsite concentrations and dose consequences. The applicant's routine release atmospheric dispersion site parameters include a maximum long-term average site boundary atmospheric dispersion factor or chi over Q value, and a deposition factor, or D over Q value.

The routine release chi over Q and D over Q values are used to help demonstrate compliance with the offsite concentration criteria in 10 CFR Part 20, and the dose criteria in Appendix I to 10 CFR Part 50.

The staff identified an open item when it reviewed the applicant's routine release chi over Q and D over Q values. The staff found that the applicant's routine release atmospheric dispersion site parameters did not bound the corresponding site characteristics for the three ESP sites.

The three ESP sites have higher routine release chi over Q and D over Q site characteristics, as compared to the applicant's routine release chi over Q and D over Q site parameters, implying that the three ESP sites had worse dispersion characteristics than that required by the reactor design.

The applicant states that it derived its routine release chi over Q and D over Q site parameters using data derived from 27 U.S. sites and one petitioned site, and chose the bounding values. The staff believes that the three ESP sites may have high routine release chi over Q and D over Q site characteristics, because the ESP sites use bounding conservative assumptions in generating their site characteristics, such as assuming ground-level releases.

To confirm this assumption, the staff has asked the applicant to provide the technical basis and input assumptions it used to derive its routine release atmospheric dispersion site parameters. This information will be useful to each COL applicant in developing its site-specific routine release chi over Q and D over Q site characteristics. this is open item 2.3-10.

I think part of the confusion here is that the plant stack is not part of the standard plant design. And I think what probably the applicants need to be aware of, that they may need to have an elevated stack in order to get the lower chi over Q values necessary to meet the site parameters. So that's kind of where this RAI -- this open item is headed.

To summarize, the meteorological open items are as follows. The applicant should provide additional precipitation and roof design site parameter. The applicant should explain why the EAB chi over Q site parameter -- value of 2.2 times 10^{-3} seconds per cubic meter, was not used in all of the DCD Chapter 15 accident dose evaluations.

The applicant should provide chi over Q site parameters for all control room filtered air intake and unfiltered in-leakage locations, and potential release pathways to the environment for each accident. And the applicant should discuss the assumptions used in deriving its routine release chi over Q and D over Q site parameters.

The meteorological COL action items can be summarized as followed. The COL applicant is to provide information on climatic and atmospheric dispersion site characteristics. Note that this information may be already contained in an ESP, if the COL applicant is referring to such a permit.

And, second, the COL applicant referencing the ESBWR should demonstrate that the meteorological site characteristics for a given site fall within the ESBWR meteorological site parameters. Should the meteorological site characteristics not fall within the ESBWR meteorological site parameters, the COL applicant must provide supporting justification to an exemption or amendment that the proposed facility is acceptable at the proposed site.

MR. KRESS: Why wouldn't you just say that the COL applicant must demonstrate they meet the regulatory dose criteria?

MR. HARVEY: The idea was is that the dose calculation has already been done in the DCD, if they can show the chi over Qs overlap.

MR. KRESS: But once you've got chi over Q, you've already done most of the work.

MR. HARVEY: That's correct. Now, if the chi over Qs don't fall on the right area, then they have to open up the whole calculation and rethink it.

MR. KRESS: But all they have to do is show you the chi over Q values.

MR. HARVEY: Yes.

MR. KRESS: Okay.

MEMBER ABDEL-KHALIK: Where does it say that all parameters used for design certification and review have to be bounding for ESP or pending COL applications?

MR. HARVEY: It doesn't say that.

MEMBER ABDEL-KHALIK: So why are we doing this --

MR. HARVEY: It's in the regulations. I can't --

MR. KRESS: Oh. Isn't that a choice of the designer?

MS. CUBBAGE: Right. The standard review plan discusses parameters -- or the site parameters being reasonable, but the requirement -- were you speaking to the requirement that the COL applicant meet them? That's in Part 52, the COL applicants are required to ensure that their site --

MEMBER ABDEL-KHALIK: I'm asking the opposite question.

MS. CUBBAGE: The opposite, the determination on whether they're acceptable, what's in the design certification?

MEMBER ABDEL-KHALIK: Right. I mean --

MS. CUBBAGE: Yes.

MR. HARVEY: -- we didn't want -- see if this answers you question. We don't particularly want to approve a design certification that's not going to have a high probability of being sited anywhere. To me, it seems to be a waste of staff's time and the applicant's time. If they've chosen site parameters that are not realistic to what they're going to find when they look at a specific site.

MEMBER ABDEL-KHALIK: But it doesn't necessarily mean that each and every parameter used in a design certification review has to be bounding for all pending COL applications.

MS. CUBBAGE: You're right.

MEMBER SHACK: I think they just raised the question, since these were sites that were sort of considered for this one, why there was a difference. I think the answer is the -- you know, the regulation says you have to have parameters that are applicable to a reasonable number of sites, and so, you know, not necessarily bounding, but if you happen to be a candidate for a site, you sort of at least raise a certain curiosity as to why it doesn't seem to match.

MR. KRESS: There is some question about what's meant by a reasonable number of sites.

MEMBER SHACK: Yes.

MR. KRESS: You know, if you can find three sites, why you -- maybe that's all you need.

MEMBER SHACK: Well, you know, I think they could argue that these -- well, I mean, they picked their chi over Q from 27 sites --

MR. KRESS: I know. That's certainly a reasonable number.

MEMBER SHACK: But, you know -- but then you come up with a difference, and then, you know, you want to understand why there's a difference. It seems to me a reasonable question.

MS. CUBBAGE: I believe we weren't necessarily questioning the difference, but we wanted to have enough information to understand in light of the fact that we knew that the COL applications would have an issue.

MR. HARVEY: In fact, two of the COL applications I think are planning to use this particular --

MS. CUBBAGE: Design, yes.

MR. HARVEY: Two of the ESP sites are considering this design.

MR. KRESS: Oh. That makes it very specific.

MR. HARVEY: Yes.

MS. CUBBAGE: Right. Right.

MEMBER ABDEL-KHALIK: Thank you.

MR. HARVEY: Anything else on meteorology?

MS. JONSON: I think we're ready to move

on to --

MR. HARVEY: I'll introduce Ken See.

MR. SEE: Good afternoon. My name is Ken See. I'm a hydrologist in the Hydrologic Engineering Branch. I'm going to talk about Section 2.4, hydrologic engineering.

Section 2.4 is comprised of 14 subsections, which I have listed here on the first two slides. In the interest of time, I'm not going to delve into each subsection. I think the titles speak for themselves. If there's any questions regarding a section, feel free to speak up.

What I do want to point out that has been mentioned previously -- that Section 2.4 involves site-specific information, and as such you'll see -- if you could go to the next slide, Andrea -- we have COL action items in each one of these sections. And in reviewing these, we found, you know, that to be acceptable.

Next slide, please.

Unlike meteorology, we had an easy time. We only had two parameters to deal with -- maximum ground water level and maximum flood level. And as such, a COL applicant will of course have to demonstrate that they fall within these parameters, or go get a revision or a waiver.

As far as reviewing these values, the NRC -- I think this was mentioned earlier -- the NRC reviewed the utility requirements document that GE referenced in their DCD, and put out NUREG-1242, Volume 3, Part 1, where they found the values to be acceptable and we concur with that.

Next slide, please.

Currently, there are two confirmatory items. This first one deals with the possibility of freezing and the isolation condenser, and passive containment cooling pools.

Traditionally, as a hydrologist, I would be looking at maybe in an active plant we'd be looking at an ultimate heat sink, with a 30-day supply of water. This being a passive design, they only have to meet a seven-day requirement.

Typically, we would be looking at freezing in that pool of water. Even though this is a passive design, we felt that we should at least look into the possibility of freezing. And through our RAI process, GEH has committed to heating that water and eliminating the possibility of freezing. So we found their response to be acceptable.

Next slide, please.

This last item has to do with liquid effluent releases in ground and surface water. Originally, GEH claimed that this section did not apply to an ESBWR due its mitigation capabilities. However, through our RAI process we've been able to get a commitment from GEH to have a COL action item for this section, and to provide the source term for repostulated single tank failure and to incorporate steel liners in their liquid waste tanks.

And I do want to mention there's a branch technical position which may be helpful for you. It's Branch Technical Position 11-6. It's postulated radioactive releases due to liquid containing tank failures. It was a supporting document in our -- I won't use the word "arguments," but back and forth with GEH.

PARTICIPANT: Discussions.

MR. SEE: Discussions. That's a good word, yes. And you'll find reference to that in the SRP 2.4-13 as well.

Next slide, please.

MEMBER SHACK: What did they have instead of steel liners?

MR. SEE: I believe they just -- and correct me if I'm wrong -- I think it was just a spray. They're concrete, and then they had a spray.

Next slide. Thank you.

What I'm trying to point out here that we have an ongoing responsibility in the secondary reviewer area for Section 3.4.1. Initially, there was an RAI that got issued under Chapter 2.4. In retrospect, we felt that the plant systems folks -- balance of plant Branch 2 -- would be better suited to take the lead on this issue.

So we had a discussion with them, and they agreed to take the issue. And so we've passed the ball to them. You know, we haven't passed the buck, we've passed the ball. So -- but we have a secondary review responsibility there.

That's my last slide, if there are any questions.

(No response.)

Okay. I'd like to introduce Dr. Cliff Munson, who is going to talk 2.5.

MR. MUNSON: All right. For those of you who have done some ESP reviews, you'll appreciate that the geology, seismology, and geotechnical engineering section has been reduced to just a few numbers and a few conditions, as opposed to the hundreds of pages which you'll remember for North Anna and Clinton and Grand Gulf. So all that information is provided in the COL application or an ESP application. So there's very little here in Chapter 2.5.

Some of the conditions -- and I think GEH covered them already -- are no permanent ground deformation from faulting, no soil liquefaction under Category 1 and 2 structures. There are some geotechnical soil parameter minimum values for shear wave velocity bearing capacity, angle of internal friction, and then different settlement values and slope stability factors.

One thing I did want to go over with you, though, is the SSE, which you had some questions on earlier. It's a combination of a Reg. Guide 1.60 design spectrum anchored at .3g, and the North Anna ESP site-specific SSE. So if you go to the next slide, you'll see a picture of it.

The part from 0 to about 10 Hertz is the Reg. Guide 1.60.3g, which you've seen for AP600 -- or similar to AP600, AP1000, and ABWR. The issue is that for rock sites, like North Anna, and some of the other rock sites, they have extremely high -- large high frequency ground motions from very moderate earthquakes. So GE, in an attempt to cover that, included the North Anna SSE as part of their design -- overall design SSE. So --

CHAIRMAN CORRADINI: That's the second bullet.

MR. SEE: Yes, that hump that starts at about 10 Hertz is the North Anna SSE.

CHAIRMAN CORRADINI: So I have a -- since I am totally out of it here, why do they have a dip? I mean, if I was an engineer, I'd smooth it out to make it look -- so is there something -- what am I missing?

MEMBER POWERS: I would be very suspicious of Cornelius --

(Laughter.)

CHAIRMAN CORRADINI: How sure am I there's a dip at 10 Hertz and at 1G?

MR. MUNSON: There's a dip, because they put it there. I mean, that's --

(Laughter.)

-- what they chose for their design -- they could draw any SSE that they want right now for their -- I mean, they have to show that their structures, systems, and components under -- can withstand that design ground motion right there. So that's Chapter 3, which you'll -- I don't know when Chapter 3 is coming.

MS. CUBBAGE: It'll be in the future, but then, you know, that dip would be -- is basically a restriction such that a site, if -- if the site characteristic is above, they --

MEMBER SIEBER: There are two different curves, though, right?

MR. MUNSON: Right. So that's where they intersect.

MEMBER SIEBER: That's why it doesn't make sense.

CHAIRMAN CORRADINI: Well, it didn't make sense. That's why I'm asking.

MEMBER POWERS: Well, no, it -- I mean, it -- again, it's just a bounding spectrum that you've got to fall below.

MEMBER SHACK: You just didn't want it to drop off too much at high frequency, so they --

MR. MUNSON: Right.

MEMBER SHACK: -- stuck one on.

MR. MUNSON: So the -- what we've seen from a number of rock sites that the -- just the Reg. Guide 1.60 alone doesn't cover it, and that the site ground motion exceeds that, so this is --

CHAIRMAN CORRADINI: So maybe this is the wrong time to ask my question. So that's a line. I see a big gray bar instead of a line, and I'm kind of curious where -- how fuzzy is that line in reality?

MEMBER POWERS: It's not a reality.

MS. CUBBAGE: This --

CHAIRMAN CORRADINI: If that's a criterion, and then I go to the site, and I have a -- seriously, am I going to have an uncertainty band around how the site behaves?

MEMBER POWERS: The uncertainty band is the size of the plot.

CHAIRMAN CORRADINI: But they will draw a curve --

MEMBER POWERS: They will draw a nice, sharp curve, that presumably bounds what they are going to get.

MR. MUNSON: Each site will come in with its own site ground motion, which is a representative of the local and regional earthquakes and the local site conditions. They'll define their ground motion based on that site and then compare it to that.

MEMBER SIEBER: Maybe I could ask a question to prove that I know nothing about this. You can have a hard rock site, and you can have a site where you have no soil liquefaction. What's in between? I mean, in order to have no liquefaction, you don't have to be hard rock, right?

MR. MUNSON: Right. In fact, sites that have compacted soils that -- consolidated soils, they're not going to have a liquefaction issue. It's loose, sandy soil that's going to be excavated away.

MEMBER POWERS: When we come to the Vogtle ESP, we'll get to go into this a lot.

CHAIRMAN CORRADINI: Why? Are they sandy?

MEMBER SIEBER: I remember when we found out that we thought we were hard rock, and then ended up driving hundreds of -- piles after we found out there was liquefaction. It was expensive to find that out in the middle of construction.

MR. MUNSON: Each of the sites do a liquefaction analysis and determine a factor of safety for their site. So that's a big part of our ESPs and COLs.

CHAIRMAN CORRADINI: So the site has to come in with a curve that's below this.

MR. MUNSON: Right.

CHAIRMAN CORRADINI: And that's a bounding curve, and this is a criterion.

MR. MUNSON: This --

CHAIRMAN CORRADINI: I'm trying to -- I'm still trying to understand. I'm sorry.

MR. MUNSON: The site SSEs determine based on that -- are Regulatory Guide 1.208, which references that ASCE Standard 43-05, which is referred to as the performance-based approach. So that's how the site SSE is determined.

I wouldn't necessarily call it bounding, but it's based on, you know, 10,000, 100,000-year ground motion type levels for different -- for earthquakes that can affect the site.

MEMBER SHACK: If we wanted a 10^{-7} ground motion, we could get a biggie.

(Laughter.)

MR. MUNSON: Yes. Of course, you know, we don't --

MEMBER MAYNARD: This is basically the criteria that the designer used to design the plant and specify the equipment requirements. They could have just drawn a box that said, "Our stuff is designed to this," and let the licensee come in below that. But they chose to depict two curves, put them together for the criteria.

MR. HINDS: Yes, this is David Hinds from GEH. I'm just confirming that these were the criteria that we used to design the structures and systems, and it was chosen with the Reg. Guide plus the North Anna high frequency as stated, such that it should -- it should be a bounding-type curve for many sites, but each individual COL will have to confirm the relation to the individual site parameters, to these generic parameters that we have chosen to design the plant.

CHAIRMAN CORRADINI: Based on the reg. guide. Go ahead. Based on the reg. guide.

MR. HINDS: We, again, used the reg. guide for the lower frequency, and the high frequencies above the reg. guide.

CHAIRMAN CORRADINI: That I understood. But I was kind of going back to what Cliff had said before, that any specific site is going to have to use a procedural approach to see where they fit.

MR. HINDS: Right.

MEMBER ABDEL-KHALIK: But from a realistic standpoint, would it have made any difference if you had eliminated this dip when you did the analysis?

CHAIRMAN CORRADINI: I can only guess as an engineer that you left the dip there for a reason. And I'm trying to get somebody to tell me, why did you leave the dip there? So if you don't want to tell me yet, I'll just remember it, and I'll find it again later.

(Laughter.)

I will not forget this. So feel free.

MR. HAMON: I don't know if I can give you a full answer, but basically this is a logarithmic scale, so there is a lot of -- if you draw a straight line across there, you're going to have much higher assumptions in that frequency range that potentially can impact the design of various components and/or the building itself. And so they were trying to be conservative, but not overly conservative, because that potentially adds cost to the plant unnecessary. So --

MR. MUNSON: Another thing to note is the frequency range of interest for structures is basically between 2 and 10 Hertz. That's where the natural frequency of these structures are. So that's where we're most concerned, that's where we focus our -- you know, that's where the engineers focus their attention.

MEMBER BLEY: And where do the components lie in their natural frequencies? I don't remember. It has been a -- is it 5 to 10, or 10 to 20?

MEMBER POWERS: I think they're a little higher because they're small. That drives the --

MEMBER BLEY: But they're still like around 20, somewhere in there?

MEMBER POWERS: Fractioning the relays and things like that. Some things --

MEMBER BLEY: If they get much above that, then they aren't moving much. Yes.

MEMBER POWERS: I mean, there are actually things that come up in the plants that hit 100 Hertz, but it --

MEMBER BLEY: I'm trying to remember yesterday. Are they going to have to do a site-specific seismic PRA for all of these, or are they still going to do margin studies? Margins are okay for this generation.

MEMBER POWERS: Yes.

MR. HINDS: This is David Hinds again. Just -- I think the basic answer to your question is these were two curves, and that's simply the intersection of them, meaning the curves were not modified at the intersection, is my understanding, meaning the reg. guide curve intersected the North Anna curve at that point that you're pointing out there. It's very --

CHAIRMAN CORRADINI: So let me ask you a question. You have a customer that comes in, and their curve for their site at 1 Hertz is -- I can't read that, but that looks like about .8g to me, and they get .85g. Do I start worrying? Do you know what that means? So that means if I get within a factor of 2 of that, I start worrying?

MR. MUNSON: Any time you exceed that you're going to -- we're going to have --

CHAIRMAN CORRADINI: So if that's .8 at 1 Hertz, and they get .79, they're okay.

MR. MUNSON: They analyze to that, hopefully -- to that design.

MEMBER POWERS: Trust me, we would look at how short the pencil was to get to the .79. But in the end, you'd say if -- if you were happy with where they got the .79, they passed. But they get close scrutiny.

CHAIRMAN CORRADINI: So we're going to get back to this again, but just one last educational question. So to get the curve below it, it's not calculation. It is expert judgment?

MR. MUNSON: No, it's a lot. It's about the calculation and expert judgment, lots of analysis. You have to characterize all of the earthquakes within a 200-mile radius of your site in terms of their magnitude, their location, their recurrence, and then you have to estimate the ground motion from those earthquakes, and then your local site conditions, how that ground motion gets amplified as a -- as it climbs up through the soil.

CHAIRMAN CORRADINI: Those are the calculations if you knew the epicenter and you knew the strength of the earthquake. But many of the earthquakes in the United States are so historically long ago there are suppositions as to what the initial strength is. Isn't that --

MR. MUNSON: That's why we use a probabilistic --

CHAIRMAN CORRADINI: Source term -- I

mean, it's like an explosion. It's the source term that I have to assume, and then I can probably get anywhere I want.

MR. MUNSON: Well, we defined aerial -- large aerial source zones where we've had earthquakes, and we postulate that an earthquake can occur anywhere within that zone with a given magnitude and recurrence, and then we model those earthquakes, and we do a probabilistic approach to determine the overall ground motion.

CHAIRMAN CORRADINI: Right. But that initial earthquake that you would specifically put in various places, various depths, has got to be based on some historical --

MR. MUNSON: Right. It's either based on the seismicity or we have liquefaction evidence that an earthquake occurred thousands of years ago, because it left some geologic feature.

MEMBER SIEBER: Like New Madrid -- you find liquefied areas all around that.

MR. MUNSON: Yes. If we do this -- on ESPs, we cover this hundreds of pages, just doing all of this stuff. So --

CHAIRMAN CORRADINI: Thank you.

MEMBER POWERS: You can spend hundreds of pages describing the geology.

MR. MUNSON: Right.

MEMBER POWERS: And we spend about 20 pages saying, okay, here's the soil liquefaction studies.

(Laughter.)

And here's why we don't believe the USGS stuff.

MEMBER SIEBER: Is 200 miles the limit? Because I hear --

MR. MUNSON: No. We --

MEMBER SIEBER: -- plants 800 miles away talking about Charleston and New Madrid and --

MR. MUNSON: Well, the 200 is in our reg. -- is the number that was in Reg. Guide 1.165. But we go outside that for large things like New Madrid or Charleston. We definitely go outside 200.

MEMBER POWERS: And it's totally reasonable on the east coast where the ground is not very dissipative. If we go on to California where the ground is very dissipative, then you don't have to go quite as far. But then, it's not very far to the earthquake and the faults either.

(Laughter.)

MEMBER BLEY: To find a new fault, all you need to do is drill a hole and --

(Laughter.)

-- build a house.

MEMBER POWERS: Hire a graduate student in geology and they'll find the faults for you.

(Laughter.)

MEMBER SIEBER: Soil structure is just as important as the seismicity and frequency of --

MR. MUNSON: The local site conditions have a big part in all of this.

MEMBER SIEBER: Right.

CHAIRMAN CORRADINI: Thank you.

MR. MUNSON: That's all I have.

MR. SHOUABI: This is Mohammed Shouabi of the staff. I want to thank the Committee. This concludes our presentations on the three chapters that we presented today, and the overall yesterday of where we are in terms of certifying or reviewing this design.

We had a very productive one and a half days with the Committee, and we do appreciate your time. These were three chapters. We're planning to come back with four more chapters later on in the month. Those are 5, 10, 11, and 12.

And I guess one thing that I would ask is if you have any guidance for us in terms of when we come back for the full Committee, what would you like us to come back and present?

CHAIRMAN CORRADINI: Well, let me just go around and see if there's -- I have a couple of things I've written down of things to remember for next time, but I'll just go around the group and see if there's any last comments for the three chapters, and then we can talk.

Tom?

MR. KRESS: Personally, I thought there was pretty good SERs for these three chapters. I didn't see anything that I thought would be -- stand in the way of approving these for design certification. I was a little taken aback by the fact that you used three sites to show that some of the things were -- parameters were representative of a reasonable number of sites. That was the staff -- it wasn't a comment on the GEH, because they -- they looked at more sites. But I just don't think three sites represent a reasonable representation of a lot of sites. Other than that, I still have some -- still have some problems with some things I want to bring up at the COL stage.

CHAIRMAN CORRADINI: Okay.

(Laughter.)

I wonder what they might be.

(Laughter.)

Okay. Thank you, Tom.

John?

MEMBER STETKAR: Only two things that -- that I sort of noted from the electrical Chapter 8. One was the -- in my opinion -- apparent continuing confusion about what is the rating of a particular battery in the plant. Whether that makes much difference, it -- I think the staff and GEH should be on the same page as far as what that really means.

And the other was this environmental qualification issue, which is admittedly kind of an inter-system thing, and I know it will probably be addressed under the support systems or some other area. But I just don't want to -- I don't want it to fall in a crack somehow, so the ability to maintain an adequate operating environment, in particular for things like the inverters, the DCIS, during a station blackout situation, prolonged, 72 hours.

MS. CUBBAGE: Right. In Chapter 3, specifically 3.11 is the EQ section, so you'll be hearing about that when the Chapter 3 discussion happens later.

MEMBER STETKAR: Okay.

MS. CUBBAGE: So --

CHAIRMAN CORRADINI: Said?

MEMBER ABDEL-KHALIK: I agree with John's comment regarding the batteries. Listening to GE's response, there were actually two responses that were contradictory. And it would be a good idea to -- to clarify that.

CHAIRMAN CORRADINI: Anything else, Said?

MEMBER ABDEL-KHALIK: No. I don't have any issue.

MEMBER POWERS: Well, the staff -- both the applicant and the staff did a good job on this design certification as far as I can tell up until now, so I really have encountered nothing except -- the only interesting things in quality assurance that we're going to have to digest a little bit, but other than that I -- I think it --

CHAIRMAN CORRADINI: Do you want to tell

me more, so that I remember those interesting things?

MEMBER POWERS: No.

CHAIRMAN CORRADINI: Okay.

(Laughter.)

I didn't think so.

(Laughter.)

MEMBER POWERS: But, no, I think this is going --

CHAIRMAN CORRADINI: Okay.

MEMBER POWERS: -- that it has gone well for these three chapters.

CHAIRMAN CORRADINI: Bill, you're okay.

Otto?

MEMBER MAYNARD: One comment on the QA. I found it good that the staff's audit only found problems with missing some dates rather than any technical issues with the resolution of the items there. I really don't have anything else.

CHAIRMAN CORRADINI: Jack?

MEMBER SIEBER: I think General Electric and the staff both did a pretty good job. I have a couple of minor things, but not significant enough to mention. More things I have to learn.

CHAIRMAN CORRADINI: Well, I have learned a lot. I wanted to thank GEH and the staff for all of their efforts, and I guess we'll see you all in a couple weeks, three weeks to be exact, right?

MS. CUBBAGE: October 25th.

MEMBER SIEBER: Save me a set of slides and handouts.

CHAIRMAN CORRADINI: all right.

MS. CUBBAGE: And that will be a very full day, so we might -- might need to think about a day and a half or --

CHAIRMAN CORRADINI: We'll caucus right after this and talk about the plan.

MS. CUBBAGE: Yes. We are --

CHAIRMAN CORRADINI: Thank you, all.

(Whereupon, at 3:25 p.m., the proceedings in the foregoing matter went off the record.)