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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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AP1000 SUBCOMMITTEE

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OPEN SESSION

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TUESDAY

APRIL 5, 2016

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:32 a.m., Harold B. Ray, Chairman, presiding.

COMMITTEE MEMBERS:

HAROLD B. RAY, Chairman

RONALD G. BALLINGER, Member

DENNIS C. BLEY, Member

CHARLES H. BROWN, JR. Member

MICHAEL L. CORRADINI, Member

JOY REMPE, Member

PETER RICCARDELLA, Member-at-Large

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member

ACRS CONSULTANT:

WILLIAM SHACK

DESIGNATED FEDERAL OFFICIAL:

PETER WEN

ALSO PRESENT:

RYAN BURDA, Westinghouse

ED CUMMINS, Westinghouse

TIMOTHY DRZEWIESCKI, NRO

JON DURFEE, Westinghouse

GREG GALLETTI, NRO

ANNE-MARIE GRADY, NRO

DON HABIB, NRO

MICHELLE HART, NRO

ZACHARY HARPER, Westinghouse

TERRY JACKSON, NRO

THOMAS KENDZIA, NRO

THOMAS KINDRED, Westinghouse

ROBERT KITCHEN, Duke Energy

RONALD LaVERA, NRO

JOHN McKIRGAN, NRO

PETER MORRIS, Westinghouse

PRAVIN PATEL, NRO

MALCOLM PATTERSON, NRO

ANDREW PFISTER, Westinghouse

PAUL PIERINGER, NRO

JAMES SCOBEL, Westinghouse

LARRY TAYLOR, Duke Energy

JAMES THORNTON, Duke Energy

BOYCE TRAVIS, NRO

ERIK WAGNER, Duke Energy

AARON WILMOT, Westinghouse

JACK ZHAO, NRO

*Present via telephone

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P R O C E E D I N G S

8:32 a.m.

MEMBER RAY: The meeting will now come to order. This is a meeting of the ACRS AP1000 Subcommittee. I'm Harold Ray, Chairman of the Subcommittee.

ACRS members in attendance are Ron Ballinger, Pete Riccardella, Gordon Skillman, Mike Corradini, ACRS Chair Dennis Bley, John Stetkar, and Joy Rempe. We will be joined, we believe, a little later by Member Charles Brown. Also at the table with us is our consultant, Dr. Bill Shack, former ACRS member and chairman. Peter When of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the exemption request in the Levy Nuclear Plant Units 1 and 2 Combined License Application. These exemption requests include departures from the AP1000 certified design, which contain: one, passive core cooling system condensate return; two, main control room dose; three, main control room heatup; four, hydrogen vending inside containment; and, five, neutron flex doubling algorithm compliance with IEEE-603. So there are five exemptions, we

believe the consensus seems to be, with six departures, two of which are associated with the first exemption I read.

If we run out of things to talk about today, we may get into the definition of exemptions and departures. But for now, we'll just leave it at what I said.

We will hear presentations from Duke Energy, also known as Duke Energy Florida in this case; Westinghouse; and from the NRC staff. The Subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and action, as appropriate, for deliberation by the full Committee.

As shown on the agenda, some presentations will be closed in order to discuss information that is proprietary to the licensee and its contractors, pursuant to 5 USC 552(b)(c)(3) and (4). Attendance at this portion of the meeting dealing with such information will be limited to the NRC staff, licensee representatives and their consultant, and those individuals and organizations who have entered into an appropriate confidentiality agreement with them. Consequently, we will need to confirm that we have only eligible observers and

participants in the room, and the closure of the public phone line will occur for the closed portion.

Currently, the first closed portion is scheduled for 9:30. It may be sooner or later. And at the time it's closed, we will estimate when we will resume the open meeting.

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. The detailed procedures for the conduct and participation in ACRS meetings were published in the Federal Register November 8th, 2013. We have received no written comments or requests for time to make oral comments or 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 throughout the meeting room when addressing the Subcommittee. Those of us at the table need to recognize the green light will indicate your microphone is on and the contrary when it's off.

Participants should first identify themselves and speak with sufficient clarity and

volume so that it can be readily heard. We have several people on the public phone bridgeline listening to the discussion. To preclude interruption of the meeting, the phone line is placed in a listen-in only mode. We will open the line for any public comment at the end of today's meeting.

We will now proceed with the meeting, and I call on John McKirgan of the NRO staff to begin. John?

MR. McKIRGAN: Good morning, Mr. Chairman. Good morning, members of the Committee. I just wanted to take a moment and thank the Committee for their time today. The staff has been working very hard to address these five generic issues as we move to finalize our SER for the Levy COL application. You may recall we met with the Committee previously on the condensate return issue, and there were a couple of items that the Committee asked, and we hope to address all of those issues.

Our goal here today is to answer all the Committee's questions on these five issues, and we would be looking for a letter. We appreciate very much the quick turnaround in that this is kind of a special Subcommittee meeting in advance of a full

Committee meeting on the 7th, and we know that puts the Committee through a bit of extremis to turn a letter around that quickly, and we do appreciate the Committee's time.

And with that, I'll turn it back over to you, Mr. Chairman.

MEMBER RAY: Thank you. Very good. Thank you. We will, as we discussed previously, make best efforts in that regard, but we can make no commitment until the full Committee meets and has had an opportunity to review the presentation at that time, as well.

We begin, I believe, with Bob Kitchen of Duke and Andy Pfister of Westinghouse. If they could come to the table, please, we'll be ready to begin.

MR. KITCHEN: Good morning, Mr. Ray and members of the ACRS. I'm Bob Kitchen with Duke Energy. Andy Pfister, who is manager of Systems Integration with Westinghouse, will also help with some of the presentation.

As we get started, I guess, first, I want to express appreciation to the staff for their support in working through the review. It's been quite a process to get to this point, and we've had

excellent support from the staff and always professional support. Also, we extend appreciation to the ACRS for, as John pointed out, the quick turnaround. I think it is a bit unusual to have a subcommittee, and we hope to move to the full Committee on Thursday. I know that's a quick turnaround, and we appreciate your help in doing that.

Mr. Ray asked me this morning, well, is it Duke Energy or Duke Energy Florida? I guess the answer is yes. Actually, the license holder is Duke Energy Florida, but, as you'll see on our slide templates, Duke Energy is our enterprise holding company, and that's who I represent.

We're going to talk about the generic issues that Mr. Ray outlined this morning and this afternoon. We do have quite a full agenda. We're going to try to step through this quickly and cover the points that the Committee needs. And as always, if there is anymore discussion, we're certainly ready to do that. We have quite a support team with us today from Westinghouse and Duke.

This morning, as you all realize, of the five issues, I think the condensate return is certainly the most complex and has been the most

involved to work through and, of course, accordingly, we have allotted more time for that. So it actually goes into this afternoon. I think we've got the NRC staff presentation right after lunch.

And then we'll go through the other four issues: operator dose, main control room heat, hydrogen vent source range, flex doubling, and try to step through those. They're less complex, and I believe that we can step through those certainly more quickly.

So right now we're just going to talk a bit about condensate return, and I'll try to introduce and provide an overview. We did, as John mentioned, we met with the staff, I mean with the ACRS some time ago, and you guys have seen actually an information presentation from Westinghouse and then followed by an ACRS Subcommittee review. So we're not going to go through that little detail again but, just to touch base, we're going to cover a few things to get to the right starting point.

We'll try to cover why the design change, what is the design change, very brief; what is the licensing basis, which I think is important to make sure that there's a common understanding

because that's obviously what we're changing, so what is the requirement. And we'll give a very short update from where we've come from the last time we met with the ACRS.

In the closed session, we're going to go into, as you would expect, a lot more detail. Tom Kindred with Westinghouse will be doing the bulk of that presentation, but we'll get into an in-depth discussion of the analyses that support what we're presenting, and I would think that's the area that will probably be of a lot of interest to the ACRS.

And then, finally, in the closed session, we're going to cover just plant recovery a bit, you know, how would you get back, how would you recover the plant given the conditions that would exist.

I want to step back a little bit and talk about quality assurance and corrective action program, what do we do in terms of vendor oversight. I think there were some questions in terms of what we had in place and how we operated.

Some of this is very basic, and we don't have to spend a lot of time here, but how do we go about developing our COLA. We use the existing Duke Energy fleet QA program for the COLA development,

which is based on ANSI N45. Vendor programs, and this is not unusual, I think many of you have worked at utilities that the vendor programs, the vendor may use their own QA program, which we review and approve the use of that program. And, actually, for our specific case, the vendors that we dealt with all use NQA-1 1994 version.

So that's the way we set up our QA program for the COLA development. Our vendor oversight -- excuse me, for change to the DCD in the COLA application change, Westinghouse developed a change, and we review it and determine whether we feel we need to implement the change and then do our own owner acceptance of that change. And then the licensing changes are implemented by, in this case, a COLA update. Moving forward to post-COL, we would do that as a license amendment.

MEMBER RAY: Bob, you referred to NQA-1 for vendors. I believe it's from ASME Section 3, the QA program requirements.

MR. KITCHEN: Yes.

MEMBER RAY: All right. In this instance, the scope of the supply here is much broader than what's affected by ASME Section 3, in terms of system design and so on. So can I presume

that you do look to vendors, such as Westinghouse, from the standpoint of Appendix B? Even though they're very close and very similar, the application to a Section 3 vendor only would be more particular to the requirements of Section 3 than, say, programmatic requirements that have to do with design process.

MR. KITCHEN: We apply all of the elements of 10 CFR 50 Appendix B, the 18 criteria for QA compliance. Not all of those necessarily apply in the COLA development, but those are all included in our QA program and oversight as applicable. And that would address, as well, design control.

MEMBER RAY: Yes. I think one of the issues, that I'm thinking about anyway, is the difficulty of you, as a customer of Westinghouse, having a certified design, looking back to the program implementation as it occurred leading up to certification. That would seem to me to be an area of uncertainty, at least in my own experience, as to how one would assess that. And so I just want you to make any comments that you wish to as to whether or not the certification implicitly includes prior oversight by Vendor Inspection Branch, for example,

of programmatic implementation, what assumptions do you make, or do you go back and look and say that, in the development of this certified design, Appendix B program that was in place at that time was satisfactory?

MR. KITCHEN: Well, in this case, for the certified design, of course Westinghouse obviously has had and maintains a QA program. The NRC periodically audits Westinghouse through their Vendor Inspection Branch. We didn't, prior to -- well, we were involved in the certified design revision. The original certification was Revision 15. We did not participate in any way in that. The change to the certified design that moved to DCD Revision 19, we were very involved in that, including QA review of the Westinghouse program and routine oversight inspections of the Westinghouse QA program, which we'll talk a bit about here in the next slide.

MEMBER RAY: All right.

MR. KITCHEN: QA oversight and kind of to the points, I believe, that Mr. Ray was making here, we rely on the NUPIC, which is the Nuclear Procurement Issues Committee, which is an industry oversight. If a vendor basically has enough

business in the industry that involves the number of utilities, then we work together to do a common oversight inspection. We participate in that. Those are done every two years. It's a full scope audit of the complete program.

In addition, every two years, there's a limited scope audit, and that's done alternating, so that, in fact, we have every year a NUPIC audit of vendors. This not only Westinghouse but any vendor that we're working with. It involves a number of utilities.

And then in between, we do a semi-annual audit of performance to look at what kinds of things may have occurred. You know, typically, from a vendor, you're looking at source surveillance of procurement activities. A little bit different here in this case. We'll be certainly more interested in design control aspects of Westinghouse just because of the nature of the work that they're doing for us.

So that's the oversight. And as Mr. Ray was pointing to, this has gone on ever since our engagement with Westinghouse through NuStart activities certified design development and then ongoing as an applicant to complete our licensing process.

We're going to talk quite a bit about this, but we have the situation where we're not close on the heels of the reference COL, so there have been changes evolved that you're looking at today some, evolved from the construction development detail design to support construction. I don't think it's really a surprise that there are changes that are identified that need to be made. We look at all of those changes in terms of how do we see them impacting the license from the standpoint of the information the NRC needs to make a valid safety evaluation.

And when that's performed, we do another acceptance review before we implement a change. The five that we're talking today would be specifically those. We look at a more general just awareness of what else is out there.

And then how do we make the determination? We use a process that's outlined in the NRC document Interim Staff Guidance 11 for considerations of what changes should be brought to the NRC's attention.

So that's how we look at activities that are going on at Westinghouse and how we go about identifying what we need to include in our license

application.

Looking at condensate return, no secret here, we had some things that we learned from. This is how we were engaged with Westinghouse on design change and how we were making determination that the design change met all of our needs as a license holder. In this case, now as an applicant but as a license holder. And we identified some areas that we needed to tighten up on. You can see the list here, but it's not all-encompassing, but these were the noteworthy ones.

First of all, in this case, we didn't get these items entered into our corrective action program. Don't really have a good reason for that, other than maybe just the perspective of how you're looking at something and taking it as a certified design somewhat separate from design development that we would normally do.

We also, our initial technical reviews, we did technical reviews. But what we realized we needed to do was really put more structure around these technical reviews and make sure that there was more than just the engineer going up to visit to look at what Westinghouse had in progress and do a technical review but really more of a directive

focused review on what was being done.

We also, in looking at the corrective action program, we weren't as aggressive as we probably should have been in terms of challenging Westinghouse on significance and how that was dealt with in terms of extended condition, what else would be impacted. And then we also recognized that we could take better advantage of the NUPIC resources, which are significant, to more effectively focus NUPIC reviews based on what we received as an applicant going forward.

So we made some changes internally. Our procedures now, and just to make sure it was covered, in the procedures we use for determination of changes to our license application, we now require anything which is emergent change that we're going to incorporate be captured in our corrective action program for appropriate investigation training and historical record.

The other area we focused a lot of attention on is improving the quality of our engineering reviews to look at, basically, as I said, more structure and essentially more formality around how we were preparing for these engineering reviews. We actually developed a written review

plan, which is reviewed within our engineering group and approved by our management team on nuclear development.

There's a lot more interaction directly with Westinghouse subject matter experts in terms of what's going on, why the change, how the change is being done, options considered, you know, thought process behind the analyses, etcetera. And we are looking at the supporting analyses and reports that are needed to make the change. And then the review plan that we documented to start, we document the findings from that review plan and capture those in our corrective action program. So not that we weren't doing engineering reviews, I certainly don't want to give you that impression, but we've truly tried to focus on the structure and how those are controlled and developed.

We also include in that plan, we look at what Westinghouse has done in terms of corrective action and specifically look at where they've gone in terms of extended condition and understanding and agreement with the Part 21 evaluations that are done.

And then, finally, in terms of feeding back to NUPIC, we realized that, you know, one of

the things we can do is make sure that, you know, the teams that are going on NUPIC audits may not have been involved in these specific activities. And so we meet with the manager of Vendor Quality at Duke to make sure that he's captured and understands the things that we've seen since the previous NUPIC audit tied to what we're doing to factor that into their assessment they do, at Westinghouse in this case.

MEMBER SKILLMAN: Excuse me, Bob. Before you move on, I have a question for both you and Andy. The inspection audit from 2015 points to the condensate issue as having been identified in the United Kingdom in 2010. What confidence should we have that an extended condition review was performed and this is the only item that is carrying forward that we need to be talking about here today?

MR. KITCHEN: Mr. Skillman, if I could ask, we're going to talk on that in just a minute.

MEMBER SKILLMAN: Okay.

MR. KITCHEN: Maybe, if you don't mind, could we see if that addresses your question?

MEMBER SKILLMAN: Yes, sir. That would be fine.

MR. KITCHEN: And if it doesn't . . .

MEMBER SKILLMAN: Okay, thank you.

MEMBER RAY: Well, Bob, I want to compliment in sharing your presentation, and I think it reflects very a personal view with a thorough response to this from a QA program standpoint. And, therefore, I have nothing but positive things to say about what you've said.

I still, though, wonder in my own mind about the issue of developing a certified design without a customer to provide that oversight and whether the things that are in place during that period of time are sufficient or whether the customer should then be expected to go back and challenge the process that went on during the certification phase by a vendor and examine how satisfactory the program was that was applied. I'm not asking you to answer that question. I'm just saying that's the question that remains in my mind. It's a difficult thing for a customer to go back and examine that and he's about to speak to the Westinghouse perspective, and so you may wish to address that, as well. But I want to make that comment.

If you're ready to move on to the next presentation, that's fine.

MR. PFISTER: Yes, so just as a comment in terms of level of licensee customer oversight, applicant oversight during certification. Certainly, as Bob mentioned, through a NuStart, many of the applicants and licensees in the room were very involved in, you know, the changes that developed from Rev. 15 or the DCD to Rev. 19.

One of the other areas where it was more a holistic review and not just a review of what had been changing is, during that same time period, I'll say we took the design from what I'll call a basic design that was adequate for certification to a detailed design that's adequate for construction. As part of that process, you know, we underwent, whether it was a system or a component, you know, multiple different design reviews, you know, amongst the various disciplines of the design. You know, as part of that design review process, licensees participate, applicants participate, and that's an area where, you know, they're looking more holistically at the design that was developed for certification that was developed all the way tracing back to AP600 to provide that level of oversight and get that engagement and involvement in what was done previously and how what was done previously is being

carried forward.

MEMBER RAY: Well, that certainly needs to be done. A question might still remain whether there's a clear obligation to do it. In any event, please proceed.

MR. PFISTER: Okay. So I just want to take a few minutes here and talk about the Westinghouse corrective action process as it relates to these five issues, so this isn't focused just on condensate return and extended condition and specific items we've learned from these issues, you know, where we've seen similar issues as a result of this and incorporated those lessons learned, and really provided ourselves and our licensees and applicants to have confidence that this is it, that we've captured the big items here.

So as part of, you know, resolution of these five generic topics, we did do two root causes, two apparent causes and one limited cause analysis. Some key themes that you saw coming out from those causal analyses are really twofold, one looking at insufficient design requirements flow-down, so how do we take these top tier design requirements and flow them down, you know, to the detailed design level; and the second being

insufficient interface control as part of detailed design development between what I'll call global plan analyses and physical plant design.

So to kind of touch on a few examples that we've seen within these specific issues and how we've taken those root causes and applied those lessons learned elsewhere, you know, on something like insufficient design requirements flow-down. So I think that's really at the root of one of the topics we'll talk about this afternoon with respect to hydrogen vents and how did the hydrogen venting concern come about. It came about because our layout, our area management team didn't understand that making changes in venting locations within a certain compartment in containment had a negative impact on our severe accident analysis, and nowhere had we adequately captured that design requirement and flowed it down to our engineers doing the detailed design layout. So that's a case where we've gone back and made sure that top tier requirement was captured in the appropriate place so that our physical plant designers understand the restrictions they have or at least what the requirements that they have to balance when they go do detailed design.

You know, a second example in terms of insufficient design requirements flow-down that we'll talk about this afternoon is control room dose. So, you know, the initiator for the control room dose concerns grew back to, you know, a very early dose calculation that looked at direct streaming, and the results of the direct streaming calc were a recommendation to add shielding. That recommendation just lived in the analysis. That recommendation was never carried forward and implemented in terms of physical plant design.

So, you know, at a later date, we went back and looked at these calculations. We said the shielding doesn't actually exist. We didn't do a good job of capturing that analysis requirement and flowing it down into physical design.

Looking at areas of interface control. So a couple of interface control issues, and this is, I'll call it a common theme amongst this, other challenges we've been working through as part of detailed design and construction but a good example from condensate return.

One of the things that our physical designers didn't understand, I'll say, to a certain extent, even, you know, early on, our analysts

didn't fully understand is, you know, what happens when you add attachment place to the containment vessel? How does that affect your return rate in terms of water you have returning off the vessel back to the IRWST, an do we have adequate interface control moving forward and understand the impact of adding attachment plates to the containment vessel? And so what are our engineering processes, engineering documentation, and engineering mechanisms in place to do that?

So one of the things we've done is put interface control document in place as a means for our physical plant designers to communicate with our analysts and make sure we maintain positive control of design features such as that. Another example on interface control that we'll talk about this afternoon, control room heat loads. So what was one of the contributing causes that led to control room heat loads concern? Is it our control room designers or I&C designers or human factors designers were adding equipments at the control room, you know, without cognizance of, well, when I add these big screens or when I add this additional piece of equipment here, that actually adds a heat load to the control room, and so how are we managing

that interface between the physical designers, the control room designers, and the analysts who do the analysis for heat-up? So we've put specific engineering documentation in place to manage that interface that I'll say is an agreement that both engineering groups sign and recognize as a means of understanding how these, what can seemingly be, like, small changes add up over time and have an impact on global plant analyses, you know, other corrective actions.

MEMBER RAY: Well, let me just interject and say I think what you're describing, and I want you to be sure and elaborate on it fully, but those are good lessons and Westinghouse seems quite able to learn them and to incorporate them and benefit from the experience. But we're looking, of course, ahead when we're talking about lessons learned and to others than you all and trying to figure out is everybody going to learn these same lessons and maybe worse as we continue this process of developing new plant design, and do we have in place measures that would ensure, as best anybody can, that we don't repeat? I don't expect, I mean, I know Westinghouse does and will have, but we're looking more broadly. And so that's why this is

important what you're talking about because, at the end of the day, we have to ask ourselves, well, okay, good, this has turned out well, but what do we have in place to avoid repeating this with other vendors and other applicants for design certification and so on?

So that's why it's important for you to share with us what lessons you've learned, not because it seems like you haven't gone deep enough but we can then ask ourselves those questions, like I say. Should there be something that is applicable generally to try to prevent this from happening over and over? Please continue.

MEMBER REMPE: Actually, I mean, it sounds like you've got something in place to move forward. But when you saw that this had occurred, was there a stop and let's look and see what other changes were made and how it affects analyses? I'm not hearing you say that. I mean, how do I know you caught it all?

MR. PFISTER: Sure. So have we taken these similar lessons learned and applied them? It's a very fair question. So another area of interface control. So something that may seem very simple on the surface is how do we control the

volume of the IRWST? So IRWST is an important design input. IRWST volume is an important design input for many features, whether it's, you know, safety analysis, severe accident analysis, PRA. And at the same time, we have equipment in the IRWST, you know. If we have a challenge qualifying a support, we might have to put more equipment in there. And how do these little changes of adding equipment to the IRWST impact the downstream users of this information, and how do we control that interface?

That's a scenario where we've taken and implemented similar, you know, positive control mechanisms from this lesson learned and said here's another example where, if not properly managed, you know, it can manifest itself and issues like what we're seeing here, something that seems very simple on the surface that can lead to down-the-stream problems.

MEMBER REMPE: So you went through and said, okay, let's make sure and look at some of the key assumptions and the impact of changes we've made in the design, and somebody went through, I don't know, a thorough review of what you've done and --

MR. PFISTER: So from an interface

control perspective, we've looked more holistically and said where do we need to implement this type of engineering approach, you know, to avoid these other type downstream issues.

One of the other, I'll call it, and this is more what I would call extended condition findings, is we also, we use, you know, for safety analysis specifically, we use a database to manage all of the inputs -- you know, there are hundreds and thousands of inputs to our safety analysis -- and go through and look at, well, for each input, can we trace it back to a verified design reference, a verified engineering document?

And so one of the extended conditions we did is a full scrub of that database, and we can show that for every input that we document within that database, you know, we have traceability to an engineering document that shows where that input came from and the fact that it's valid.

You know, one of the other lessons learned in extended condition findings coming out of this effort is, initially, that database was focused on Chapter 6 and Chapter 15 analysis, and so, had we been using that for condensate return, it wouldn't have caught anything because condensate return is

sort of this one-off analysis that sits in Chapter 19. And, you know, there are several other analyses in Chapter 19, like shutdown analysis. So we took that tool that we had in place, that positive control mechanism, and we extended it to our Chapter 19 analysis.

And, you know, looking at extended condition, you know, another example relevant to the topics we'll talk about today is actually on the control room dose, the initial issue that we identified, if it was just the initial issue with respect to streaming on electrical penetration and lack of shielding, we could have solved that without tripping ISG-11. It's actually when we took that concern and that corrective action and dug deeper into it and did our extended condition that we found, you know, more troublesome issues, in particular the fact that we had an unaccounted-for source in the control room, which is the safety-related filtration system. And so that extended condition is actually what discovered the more alarming concern that led to the ISG-11 trips physical design changes and full-scale re-analysis.

MR. KITCHEN: Mr. Ray, to your question, that's certainly the challenge of Part 52. When

you're dealing with a design not complete, how do you know what you don't know? I mean, in this case, Andy has talked about both sides of this, but, you know, it was important to see the process development so that the design considered all of the impacts of the change and the assumptions.

One of the things that I think has been -- and, certainly, condensate return is a good example of that, making an erroneous assumption, not validating the assumption that underlies the design, so going back and looking at that.

The other part, though, in our case, we said, well, this is good going forward, but, you know, we've got a lot of past to deal with. So the other part of the Westinghouse corrective action was to go back and look at assumptions in all of the safety-related fluid systems to make sure that they were appropriate and understood.

MEMBER RAY: Well, I think, as I've said this a couple of times, the response that occurred and that you guys have been describing I can't find any comment about. But your point, Bob, about having to do a Part 52, that's exactly the point that I'm trying to test on here. Not that 52 itself creates it, but there's a lot of concern about the

barriers being too high already for achieving certified design. Maybe there needs to be some more sophistication in the steps involved so that people can make some steps but then be subject to backward-looking oversight or an update of the kind that you performed and that it isn't simply accepted as, well, it must have been done in the past so we'll move on.

But in any event, I appreciate your input to us on this point because, like I say, it's in the domain of lessons learned, not did you do enough in response to this. I think in response to Joy's question, you provided a couple of examples where the extended condition was examined, and I'd be glad to hear any more that you have to say about that. But please continue.

MR. KITCHEN: Mr. Skillman, did we address your question?

MEMBER SKILLMAN: You did at a specific design level. What I was really angling for was was there anything else coming out of the United Kingdom team's review that we should know about here? You've got the condensate issue. From their perspective, was there an extended condition item that we should be talking about here? I think

you've answered that through what you've responded to with Dr. Rempe, but I'd be curious is the record clear as a consequence of the United Kingdom review?

MR. PFISTER: Yes. So as a consequence of the United Kingdom review, just kind of a snapshot of where we are right now, because we have re-started that licensing process there, is that we're working through 51 generic open items that the regulator there has maintained that we need to work to closure to get our design acceptance confirmation. Condensate return is one of those 51 items, so we have looked at the other 50 and made the determination that those do not impact, those do not meet the threshold of ISG-11. Some are country-specific requirements. Some are requirements that we've already addressed within, you know, the U.S. licensing process. It's just the UK is lagging, and so it's just the nature of the regulatory process there. Out of those other 50 generic open items, none of those would rise to the threshold of tripping ISG-11.

MEMBER SKILLMAN: Okay. You've answered my question. Thank you.

MR. KITCHEN: Okay. We're going to go back just briefly on the design because you guys

have seen this quite a bit. The error in the design, as you know, was that the assumption of 90-percent return in condensate was not, and a constant 90 percent, was not a valid assumption. In fact, Westinghouse looked and did testing and determined that it was significantly much lower than that.

So we needed to do something with that, but, right off the bat, you say, well, there's a safe shutdown in the safety design basis of the DCD that talks about achieving 420 in 36 hours, and that simply could not have been done. It didn't present a safety issue in terms of threat to the public because we still have the open cooling option using ADS. Not a desirable path but it certainly works.

Looking at the change, basically, the design change, in summary, made a lot of things to improve the catchment system and improve the return of condensate from the containment line or to the IRWST gutters, down spouts, removing some of the interferences or interference with the mounting plates in the overhead areas of the containment, just various things that are strategies to improve condensate return.

As I mentioned, the licensing basis, the reason for us to make this change is basically the

licensing basis couldn't have been met if we hadn't done the change.

Let's think of what is required. Since we're going to have to change the design, what's really required? And the functional requirement, as you know, on GDC-34, which requires that you have a residual heat removal system that will keep the reactor safe, protect the fuel, protect the reactor coolant system requirements, and has some suitable redundancy. So that is a regulatory requirement that drives the safety design. SECY-94-084, which is the policy --

MEMBER RAY: Bob, back up, please. Now, we will get to the extension of this analysis that was done as part of this work later. But is there any duration that you think is inherent in this GDC-34 requirement because that's what is -- as I understand it, no analysis was done of what the duration would have been without the modifications using the assumptions that go with GDC-34; am I correct in that?

MR. KITCHEN: Well, the GDC-34 in the design is basically the design basis analysis, which, as you point out, originally was done just to the reaching stable condition, which really

terminated in about 12 hours. So one of the actions that was taken in response to staff questions was to extend that analysis using design basis assumptions out to 72 hours.

MEMBER RAY: I guess I'm trying to say was there not a problem with this as well, we just didn't quantify the problem? What would be your position with regard to compliance with GDC-34 if these modifications had not been made, which the modifications, as you point out, are driven by the 420 and 36 hours? But what would have been the consequence to this analysis of not making the modifications?

MR. PFISTER: So with respect to GDC-34, we believe the design would have still met it. It would have met it in a different manner. It would have met it by moving the open-loop cooling. Through open-loop cooling, we can maintain, we can maintain residual heat removal and maintain the fuel.

With respect to -- I think maybe you're alluding to, you know, what would have been the duration of, you know, closed-loop cooling, we have those design changes. So you are correct. We never went back and tried to analyze the old

configuration, but one of the things my colleague will talk about is, you know, we've looked at it under, we've looked at different sensitivity cases, and these sensitivity cases don't necessarily represent exactly what the design was previously because one of the things we've learned is that, before making the changes modifications, the return rate was highly variable over time. And so you couldn't necessarily assume a constant return fraction or a constant return. But try to simulate that in a simple way. You know, we've run sensitivities where we've increased a return or decreased a return fraction from the 18 percent. We're assuming now to 20 percent, 30 percent, 40 percent and, at the same time, you know, looked at modifying using better estimate decay heat values and showing, you know, could we have reached 420 in 36 hours, where is that clip, how far would we have run out.

And so under certain assumptions, you know, as you get up to 30 and 40 percent, as we talked about this afternoon, we wouldn't have met 420 even with other best estimate assumptions. But, certainly, we could have got out past 72 hours if you're taking those better estimate assumptions.

If you're taking like-for-like assumptions down to what we're using the analysis today, especially in the DBA analysis, we would not have made it to 72 hours.

MEMBER RAY: I wasn't meaning to suggest you should have analyzed the alignment under the GDC-34, sometimes referred to as Chapter 15 assumptions. I just want to establish that that was not a question that was answered for the purposes of our moving forward here.

And, of course, because ADS is open with cooling is always not the preferred but an option under circumstances in which the closed loop is no longer available, it doesn't, in my mind anyway, represent a problem from the safety standpoint or compliance with GDC-34. But because it's mentioned, it does introduce this question of some confusion of what's driving the changes that are being made. You've been clear it's the safe shutdown of 420 in 36 hours and stability it has that really cause the changes to be made, so you're going to go on and describe that. Thank you.

MR. KITCHEN: Yes, sir. We had previously talked about SECY, which is the policy statement the staff has on passive system

performance. And, you know, 420 is the number stated in SECY-94-084 as temperatures acceptable. But it doesn't rule, I mean, it doesn't say that's the only temperature. Other plant conditions are acceptable, as long as you meet stability requirements, protection of the reactor, and those sorts of considerations, and can show that. And any, well, not any -- the passive system capabilities can be demonstrated to be different by an appropriate analysis, basically.

So we're looking at this because our question is, well, what do we need to do? What can assist in doing it? If that's what it can do, is that okay?

MEMBER BLEY: Bob, would you refresh my memory? I know we chased this, especially John chased this a while back in our discussions previously. Was there a Commission SRM on this SECY or it was just a SECY? There was an SRM on it. Okay.

MR. KITCHEN: So we looked at that and said, well, the SECY specifies the 420, but it does allow an opening, an option, to look at other temperature requirements. The problem that we had to address in one form or another is the fact that

the Revision 19 statements were incorrect for a couple of reasons. Andy has talked about, you know, we had the error in terms of the assumptions, but also the DCD describes the system performance in the safety design section for 420 in 36 hours when, in fact, the analysis that's done was, whether the terminology we want to use best estimate or conservative non-bounding, it was not a design basis analysis that showed 420 in 36 hours.

So, you know, even all things given, we still needed to fix that to make it clear what was the system performance, what were the assumptions that were used to demonstrate that system performance. And so we went back to look at that. What is a fact, the DCD Revision 19, not to misstate this, the analysis demonstrates that the requirements of GDC-34 were met and that the 420 in 36 hours would be met not on a design basis accident analysis assumption.

And that's the case still for our application. As Mr. Ray pointed out, we did do a design basis accident analysis out to 72 hours. As I mentioned, the staff requested that we extend that, and we showed that the GDC-34 requirements are met, but we didn't achieve the 420 in 36 hours or

maintain the 420 for that 72-hour period. We reached a condition that's safe, stable, protects the reactor cooling system, maintains fuel integrity, etcetera, but was not the 420 in 36 hours.

So one of the changes, and I would say a key change here, is to make sure that the description that we provide in the FSAR is clear, that here are the safety requirements that the system meets and here are the license and performance requirements that the system will achieve, safety calls that are not done under accident analysis conditions.

And we talked quite a bit about the 420 in 36 hours, but the other item we needed to address is, bad choice of words to ever say the system performance is indefinite and obviously is not, and, in fact, the other thing we needed to fix was that it was a 14-day duration for the long-term operation.

So those are the two fundamental changes, I would call them, that a number of chapters affected in the FSAR, but really what we're driving to is to clearly show the safety design basis to meet GDC-34. Separately, a license

performance call, we still meet the 420 in 36 hours and can maintain that very conservatively for 14 days, more than 14 days. But it's not an analysis that's done using design basis assumptions.

MR. SHACK: If I'm doing the safe shutdown analysis for an ordinary PWR, not a passive design, when I do that safe shutdown analysis, do I use, again, a conservative non-bounding solution? I don't use design basis conditions, Chapter 15?

MR. PFISTER: So I can't say I've ever done a safe shutdown analysis for an operating reactor, but I think we have --

MR. SHACK: I just wondered if it's consistent. Is the safe shutdown analysis for all reactor types have the same assumptions, which are somehow either best estimate or conservative non-bounding, rather than design basis.

MR. PFISTER: And I think the answer is no, but you have to keep in mind that safety injection systems and the cooling systems for an active plant and are much different.

MR. SHACK: They certainly are.

MR. PFISTER: They also require, you know, a much larger degree of auxiliary support in order to operate in that longer-term period, whereas

for AP1000 the auxiliary support needed for that longer-term period, in comparison, is essentially nothing.

MR. SHACK: What I'm worried about are the analysis assumptions. Obviously, the equipment, but the equipment is designed to meet some analysis requirements. And whether those --

MR. PFISTER: Yes, available equipment is a very important analysis assumption, and so I struggle to separate the two.

MR. SHACK: Okay.

MR. KITCHEN: So this just summarizes the difference between the Levy FSAR and Revision 19 really, nothing different than I've already discussed, but the extension of the analysis to 72 hours, clarification that we used a conservative non-bounding analysis, as opposed to design basis analysis, and the duration of long-term operation, the 14 days versus indefinite.

So let me go ahead and talk a bit about just the system itself.

MR. PFISTER: Yes. So this is a little bit of a repeat of what you've heard in the past, but we thought it was good just to spend the last few minutes of my discussion and the first few

minutes of Tom's kind of reminding you what we've already told you.

So one of the first things we want to talk about is, you know, in looking at this problem, so where does all the water go, where does the steam go? We've talked about a 90-percent return rate, and, in reality, that's part of this lesson learned coming out of here is we're no longer talking about a return rate but, in fact, we're talking about a return fraction, and that return fraction, and that return fraction is a return fraction of the water that gets to the containment vessel. So why can't we talk about a return rate, you know, kind of more holistically? And it's because you have to think about where does that water go.

So, initially, there's water lost at pressurizing containment. We conservatively assume one set steam is lost at pressurized containment, it doesn't return to the IRWST, and, you know, we don't recoup any of that.

MEMBER SKILLMAN: Andy, before you change that, I respect the idea that you're manager of systems or director of systems integration, and, believe me, I understand that. How tightly controlled is the elevation, how tightly controlled

is the elevation of the top and the bottom of the IRWST two bundle to the top and the bottom of the core?

MR. PFISTER: So they're not controlled in comparison to one another, and so the top and the bottom are of the two bundle will be controlled with respect to the IRWST itself. I don't know the exact dimensions, and I'll look at Ryan, if he knows them. But I'm sure it's within inches. I'll defer to --

MEMBER SKILLMAN: That's what I'm asking, exactly what I'm asking.

MR. BURDA: My name is Ryan Burda with Westinghouse. And to answer your question, we do have ITAACs on plant elevations associated with elevations for the heat exchanger with respect to the reactor coolant system, so that's something that is very tightly controlled.

MEMBER SKILLMAN: Approximately, how tightly?

MR. BURDA: I believe that --

MEMBER SKILLMAN: Inches?

MR. BURDA: It's within inches. I'm not sure if the ITAAC specifically has tolerances on them, but I know our design drawings are within fractions of inches.

MEMBER SKILLMAN: That's enough. Thank you.

MR. PFISTER: So where else do we lose water to that, ultimately, within the analysis, we conservatively assume that we don't recoup? And so we lose water to the heat sinks. These are walls, floors, structures within containment. You can see, represented with arrow there here, that the heat sinks in this case actually are a source of losses. And these first two items are losses that we don't recoup over time.

And then after that, we start losing water to the CV or we start sending water to the containment vessel. And when we talk about a return fraction, it's really what fraction of water that's sent or steam that's sent to the containment vessel do we credit in returning to the IRWST? And for the sake of all the analyses we do and supported by the test data that was discussed previously with the ACRS, it's an 18-percent return fraction. So what that means is 18 percent of the water that goes to the steam that goes to the containment vessel is lost and not returned to the IRWST.

And so, early on, your return rate is going to be relatively low because you're losing

heat, you're losing water and steam to places like pressurizing containment, as well as the heat sinks. As you move later into the transient, your return rate overall is going to be higher because you're no longer losing nearly as much steam to those first two places, and most of your steam then is going back to the containment vessel and a portion of that is returning to the IRWST.

MEMBER BALLINGER: I understand the 18 percent, and you may have mentioned it in an earlier presentation, but what's the uncertainty on that number and how much of a difference does it make if you account for the uncertainty, which you may already have done it and maybe the 18 percent is the lower limit.

MR. PFISTER: The 18 percent is the bounding value we calculate. The specific uncertainty, I don't know what the uncertainty within our test was that supported the development of those values, but that's really where the uncertainty comes in.

One of the things we have in the later presentation is looking at do we have a cliff edge if you had 20-percent loss, 30-percent loss, your return fraction was 20 percent or 30 percent. You

know, what sort of effect does that have? And so we can get into that this afternoon, but what it does is it just pushes out that time to 36 hours slightly.

MEMBER BALLINGER: Okay. So the 18 percent, when you say bounding, it is the bottom end of the uncertainty band likely?

MR. PFISTER: It's the bottom end of, I would call it the top end of the calculated value. So one of the things we calculate is what's our return fraction over time, and we have a specific analysis that does this. And you'll see over time it varies between about 14 percent and 17.8 percent or something, so we bound the entirety of the transient using an 18-percent fraction.

MEMBER CORRADINI: Can I ask a question? I understand what you're saying. I'm just trying to understand how it fits into an analysis we'll eventually see. So this 18 percent is then back-computed to what the level is in the IRWST as a function of time?

MR. PFISTER: The 18, it's an input, yes.

MEMBER CORRADINI: Okay, all right. So when all is said and done, it has to do with,

essentially, the heat exchange efficiency and where the water was relative to the equipment?

MR. PFISTER: Yes.

MEMBER CORRADINI: Thanks.

MEMBER RICCARDELLA: As I understand it, it's time dependent, but, for the analyses, you use a constant value that's not the average but the maximum --

MR. PFISTER: Correct.

MEMBER RICCARDELLA: -- of the time dependent --

MR. PFISTER: Correct. Obviously, you have some that splashes and spills off. You know, one of the things I mentioned earlier was things like attachment plates, that you see certain losses associated with attachment plates. You also see certain losses associated with things like containment rain-out. So, you know, the efficiency of the water being returned that goes to the, you know, vertical portion of the shell versus what goes to the dome is different. You know, you're going to get a higher efficiency of return from the water going to the vertical portion of the shell than the dome. So all of this is taken into account when we're calculating that return fraction.

And, finally, over time, some of the water that isn't returned to the IRWST will go down into the reactor vessel cavity, and that's conservatively not credited as a cooling source, you know, even though, over time, that will steam and be redistributed back to the shell.

So this next slide here just really sets the stage for the more in-depth presentation we're going to go over here in the closed portion, and so what we're going to provide is an overview of the issue of, you know, looking at our analysis approach. I think Bob touched on there's really three evaluations that we've honed in on in detail as part of this analysis approach, one being, you know, a 72-hour DBA analysis; one being conservative, non-bounding, you know, safe shutdown analysis, 420 in 36 hours; and one being a safe shutdown duration analysis, so how long can we maintain it? So taking that 36-hour analysis and extending it out to show we meet at least 14 days.

Obviously, it's taken a year and a half to get back here. You know, it's much longer than we would have liked it to take. Throughout, over this last year and a half, we've done a lot of learning, specifically with this analysis, and

somewhat changed our analysis approach. So we're going to go through that in detail, talk about what some of those challenges were that we identified and had to reconcile.

You know, as part of some of those challenges and dating back to the NRC inspection in January of 2015, we did take a step back because of the accumulation of issues associated with condensate return and do a more holistic root cause analysis on the entirety of the issue, not just on, you know, the problem of the day. You know, and as part of the resolution of that and one of the issues that's, I'll say, slowed bringing this issue back to the ACRS is really examining what is our analysis tool, in this case LOFTRAN, appropriate to use for these longer-term duration cases.

So, you know, when you're looking at a 10-hour or even a 36-hour analysis, certain phenomena are important. When I extend that analysis out to 14 days, things that might be important in that first 36 hours, things that might not be important suddenly become important, you know, especially as you look at in these much longer duration. And so Tom will get up and come through what are some of those important phenomena and what

is the right analysis tool to be evaluating these longer-term transients.

And at the end of the day, you know, our conclusion was, you know, if our key figure of merit is temperature, LOFTRAN is an appropriate tool to be looking at these long-term analyses. But we recognize it has limitations, and one of those limitations we'll talk about is, once we start uncovering the bottom horizontal bundles, you know, I'll say there's higher uncertainty in the analysis results. But what we're seeing is that bottom horizontal doesn't occur until 20 days and beyond.

MEMBER SKILLMAN: Andy, when is a good time to ask one or two specific design detail questions?

MR. PFISTER: Without knowing the question, I'll say now and I'll defer if I can't answer.

MEMBER SKILLMAN: Because when we go into the other session, it could be very analytically-oriented, so let me ask one or two questions. This is Tier 1 information.

I see that you're adding eight screens and 20 pipes.

MR. PFISTER: Yes.

MEMBER SKILLMAN: I see that you are taking credit for these air-operated valves and series that close to divert to IRWST when actuation occurs. Is there any change to the circuitry or to the design bases of those valves?

MR. PFISTER: So I'm going to defer to Ryan here and let him answer this question. Ryan is our lead system --

MEMBER SKILLMAN: He's our key to getting the water into the tank.

MR. BURDA: No, there are no changes to those valves.

MEMBER SKILLMAN: Okay, thank you. And the only hardware changes are the eight screens and the 20 pipes?

MR. PFISTER: Yes, so those are the down spouts to return --

MEMBER SKILLMAN: And those are the changes to the Tier 1 tables?

MR. PFISTER: Yes.

MEMBER SKILLMAN: Okay, thank you.

MEMBER RAY: Any other questions for the open session that we've just been through? Okay. Let me make a couple of comments before we close the open session.

The agenda has us continuing in closed session until lunch, having our lunch break, and then the open session will resume at 12:30. Now, that presumes that we're reasonably efficient, as we have been so far, in following our schedule. But those on the phone line or here in the room who are not included in the closed session, we expect to resume in open session at 12:30.

With that, we'll take a short break. We do have a longer break scheduled during the closed session, so just short enough to ensure that we've closed the open phone line, public phone line, and verified that the audience is, those who should be, we'll take just a moment to let Peter take care of that, and then we'll begin the closed session. And you'll have some other folks join you up there?

MR. PFISTER: Replace us.

MEMBER RAY: Replace you. All right. Well, you can proceed to do that then.

(Whereupon, the above-referred to matter went off the record at 9:37 a.m. and resumed at 12:32 p.m.)

CHAIRMAN RAY: Okay, we are just past 12:30, the announced resumption of our open meeting. I'll ask Peter to verify that our phone lines are open. And as indicated in the agenda, we will now hear from the staff, beginning with initially, based on the condensate return

design change that was discussed this morning. And as a modification to the agenda, we did finish the closed session discussion a bit early and we're able to add, therefore, what is scheduled as a closed session this afternoon. We believe we will not have a further closed session this afternoon. But that's always a possibility, I suppose.

A couple of things to start off with before I turn it over to the staff, we had a little discussion this morning about how many exemptions and how many departures we're dealing with here. I don't know why it ever is important except that people get confused when they expect one thing and see another. Staff slide 3 and the safety evaluation both refer to there being five departures. I think we had a consensus that there are five exemptions and six departures. If I'm mistaken about that, please feel free to correct me. So that's one administrative matter.

But another and more important one is and I'll leave it to staff as to when to discuss this, we are, of course, here only discussing the application from Levy. We did refer to in talking or addressing in the Lee letter back in December, the fact that there's a design center review approach which is the Commission policy that is followed, generally, or is available to be followed, perhaps I should say. But in any event, it is important that we ask the staff their view on how these changes will be applied to other COL holders and applicants.

I note that in Section 21 of the ASE it says these departures are common to all COL applicants referencing the AP1000 design and being applicable -- or being common is a word that doesn't necessarily mean anything for sure. So we'd like the staff at some point to elaborate on how these exemptions would be implemented for other applicants, whether there might be differences in the departures that would exist for others, what the timing might be, how the review would be conducted.

I understand there's some different options that may exist, but in any event, I

believe that it's accurate to say the departures are common insofar as the changes that they represent are needed, to use another word from the safety evaluation, in order to meet the intended functional design requirements that are in the DCD.

So with that background then, Don, I'll ask you to introduce your colleagues and to make a decision as to when and how you want to address what I'll describe in general terms as the applicability of what we're addressing ourselves to here today in the context of Levy.

With that, I'll turn it over to you.

MR. HABIB: Thank you. My name is Don Habib. I'm the project manager for the Levy COL review for the staff. With me is Tim Drzewiecki from Reactor Systems, Boyce Travis from Containment Ventilation, and Tom Kendzia from Vendor Inspector.

And I'll address the two questions that you alluded to in my overview just before we start condensate return.

I wanted to start off just to give some context and history to where we are in the review process. This review -- we actually did issue an advanced safety evaluation back in 2011 and did get the letter from the ACRS with regards to conclusions and recommendations. Since that time, there have been a number of issues that have arisen, a number of applicant submittals to address those issues. They include -- well, primarily, what we're addressing in this meeting today which is the exemptions and departures, but in addition, Fukushima recommendations. We revised the safety evaluation from that and held a meeting in January 2013.

In addition, both in 2012-01, the electric loss of phase bulletin and that was submitted in 2014, and also the emergency preparedness enhancement rule, also completed and submitted in 2014.

So to clarify, first of all, about the exemptions and departures, to start off, we can say that we received five requests from the applicants and that's why in our SE, it's grouped as five

requests. Each request includes and exemption request. One of those requests includes two departures; the rest, one departure. And when I say departure, I mean a numbered departure in how those things are identified in the application.

Certainly, these departures affect many chapters and when we go through the departures individually, I think in some of the slides they identify which chapters are addressed. And I think overall, well over half of the chapters were revised because of these particular departures. So there's many, many changes, hundreds of changes perhaps, but we group them and they're grouped into the five requests and they include two departures, the condensate return being two of those departures.

With respect to applicability, that was the other question, certainly this is for Levy. Well, the other two applicants which are the William States Lee plant and the Turkey Point plant, those two applications, they have also made formal submittals to us identifying these departures and exemption requests. Those will be the same -- those are the same as what is in the Levy request. So that we know for sure.

For the licensees, they've also indicated to us that they're going to follow these departures. How they -- if they do it identically or not, I can't really say. We have to wait until we received something from them, but the indications are for the most part, they're going to be the same. Certainly, we wouldn't get to a point where we're having the 52.103(g) finding and not having these issues addressed by the applicants. The applicants haven't indicated they're going to go that direction. They do plan on addressing them. But if we did get to that point, we have the authority we could request information from them that would make them address it.

MEMBER STETKAR: For the licensees, it will have to be a license amendment, is that right?

MR. HABIB: A license amendment request, yes. And as far as the exemptions

are concerned, whenever the applicants are changing tier 1 information or technical specifications, that is in the Appendix B, Part 8 as far as the rules for changing the DCD, that requires an exemption. So that's why we have the exemptions.

So at this point I'll move on to the first one which is the condensate return.

MEMBER STETKAR: Before we get into the specific topics, I have a general question. The only place I can ask it is now, really.

In the SER, the introduction, before we get into the general topics, there's this paragraph that says, "the staff evaluated each of the departures for impact on the probabilistic risk assessment, PRA. None of them have any impact on the quantification of core damage frequency or large release frequency." And then it goes on to finally say, "The staff finds that the cumulative risk impact of these design changes and departures is negligible."

Well, in a sense that's true, it's just the fact the PRA was wrong. The PRA assumed a certain return flow rate that was wrong. So if the PRA had been done correctly for the plant, as it was in the design certification, I would imagine that this change would have shown a difference in risk, ostensibly an improvement in risk.

So I'm curious just because the PRA was wrong and was optimistic and now the analyses show that the PRA, the wrong PRA is now right, how you can draw this conclusion that the changes didn't have any effect on real risk -- real risk. I don't care what was calculated wrongly. So how do you draw that conclusion?

MR. PATTERSON: This is Malcolm Patterson. Is this mic on?

MEMBER STETKAR: It is.

MR. PATTERSON: Malcolm Patterson. I'm in the PRA and Severe Accidents Branch in the Office of New Reactors.

You're right, the PRA is now correct. We didn't change the PRA to make it

correct.

(Laughter.)

The plant was modified to make it correct. (Laughter.)

MEMBER STETKAR: Isn't it more correct in terms of -- no, I'm serious. I'm actually sensitive to this notion that we did the analysis wrong in the past and now it's okay because we fixed the plant.

Isn't it more accurate in the SER for public consumption to maybe not as bluntly as I've said it orally, but say something to the fact that AP1000 design certification PRA is based on assumptions that are consistent with the plant design as modified by these departures. In effect, the changes that assure that these elements of the AP1000 design are now compatible with the PRA calculations and therefore no changes to the design certification PRA were needed to account for these departures, without making these statements about these departures don't affect the risk. They did affect the risk. It used to be higher. It's now lower. The PRA wrongly said it was lower.

MR. PATTERSON: It does not affect the reported risk. The point is that what we're looking here are the success criteria that were used in developing the PRA. And those are unchanged. We don't look at the thermal-hydraulic analysis when we draw up the PRA.

MEMBER STETKAR: Dennis often accuses me of drawing silly analogies. If I assume that I could transport myself from New York to San Francisco in 15 minutes and did an analysis based on that, and then later built myself a transporter, then my analysis would have been correct. But right now, it wouldn't be correct, would it? It would be wrong.

MR. PATTERSON: It would be over optimistic.

MEMBER STETKAR: It would be wrong.

(Laughter.)

I don't care what the licensee says. I don't care what the applicant says. I care

what the U.S. Nuclear Regulatory Commission is making in terms of statements that sound to me -- it's a simple paragraph that I quoted, as an absolute statement regarding the effect of these changes on the real risk of the real facility. And the statement as it's read says these changes don't affect the real risk of the real facility. That's what it says.

MR. PATTERSON: The paragraph was written to address the requirements of 10 CFR 52.79(d)(1) which says that if you depart from the certified design, you have to evaluate the effect on the PRA. It doesn't say the effect on risk.

I think the applicant did that. The staff certainly did that. We're not trying to represent that the plant used to be as good as we thought it was. We're just saying that the reported results of the PRA are not changed.

MEMBER STETKAR: The concluding sentence, and I will quote it again for the record says, "The staff finds that the cumulative risk impact of these design changes and departures is negligible." It wasn't written by a lawyer. It doesn't say anything about a PRA. It is an NRC conclusion regarding the risk impact of the design changes. It's what it says.

MR. PATTERSON: I take your point.

MEMBER STETKAR: So I'd urge the staff to perhaps reconsider that introductory paragraph and how it's phrased because they certainly did have an impact on the risk, regardless of how that was evaluated in the past and regardless of how it's evaluated now. That's all. I just needed to get that out of the way before we got into the specific things. Sorry, Harold.

CHAIRMAN RAY: That is far from the only semantic problem I have. But I think we ought to proceed now with the presentation.

MR. HABIB: I've introduced the two presenters. Also on the team, Yiu Law from Mechanical Engineering and Derek Scully on technical specifications.

This is the outline of our presentation. Moving on to slide 8, this is a licensing

impact and basically what was included in the applicant's submittals, I had mentioned it was one exemption request and it included two departures. The first departure covered the actual physical changes which were the inclusion of the down spouts and the modifications to down spouts and screens and modifications to the Polar Crane Girder and the internal stiffener to service gutters. And then the second departure had to do with the long term safe shut down where the operation was changed from indefinitely to 14 days.

As previously mentioned, these two departures covered many changes to the FSAR and the numbering there that was affected is at the bottom of the page.

At this point, I'll turn it over to Boyce Travis who will continue the presentation.

MR. TRAVIS: So I'm going to briefly walk through the review history to kind of calibrate the committee. It's been a year and a half since we last met or more. And so the first formal submittal the NRC received from Westinghouse was in April 2013; the departure and exemption request which included only the design changes, not the changes to the indefinite language.

Around the same time, Westinghouse was conducting testing for the attachment plates, the losses on the containment shell. At the time, the calculations were not finished. The staff audit was in progress and then was terminated for lack of calculations. Ultimately, staff began their review in January or February of 2014 and issued REIs at that time.

In the intervening time between January and September of that year, the second departure to change the language from indefinite to 14 days was made by the applicant. In September of 2014, we met with the ACRS after finalizing the initial safety evaluation. And we were subsequently informed by the applicant of errors in the calculation involved in the pass off between the WGOTHIC, the LOFTRAN, and the two spreadsheets.

About a year later, the staff completed its review of the revised calculation

methodology. In September, we were advised by the applicant of the potential loss of sub-cooling if an Adiabatic RCS was not considered. And so staff held off finalizing safety evaluations until that issue was resolved and we finalized our SE in February 2016.

So to briefly summarize the staff findings with regards to containment impacts, the peak pressure analyses for the AP1000 is unchanged as a result of this, primarily due to the conservatisms in that analysis that don't really apply to this one.

Ultimately, any impact on the peak pressure would happen well before the condensate started to collect on the shell. And so the peak pressure analyses, the condition of the assumptions that we'll discuss, alike, maximizing heat sink area in this analysis, some different initial conditions. The temperature in containment for this analysis is lower than the maximize in an effort to maximize condensation on surfaces in containment. And so there's no impact on the peak pressure analyses.

The potential for any lower level in the IRWST following an actuation of -- so once the heat exchanger is actuated using the ADS system, is not challenged. The spargers in the IRWST are capable of discharging below. So they could be not submerged in the IRWST. They could be partially submerged or fully exposed. There's no impacts of actuating ADS 1/2/3.

The containment flood up level which is an important input in the open loop cooling analyses which in the event of containment recirculation would have happened following an ADS Stage 4 actuation is not adversely affected, even though as part of this departure, the applicant did a more detailed analyses of what would be involved in the hold up volumes in containment. There are slightly more hold up in containment now as a result of the applicant looking at like a fully wedded contact angle on some of the surfaces, but ultimately that reduction in level would not impact the open loop -- the driving head required to establish open loop cooling.

And then, ultimately the staff found the calculated condensate returning of

approximately 80 percent in the long term acceptable. So I say 80 percent because it's an asymptotic approach to what the applicant says, 18 percent losses, 82 percent. It never quite gets there, at least in what we looked at. So that's -- the 18 percent is what losses, as the applicant said, what losses from -- of what reaches the shell, 18 percent of that does not make it to the IRWST.

Obviously, in the early stages of the transient, as the applicant discussed, they have to pressurize the containment atmosphere, condense on acid heat sinks, transient films on surfaces, the floor, and so that results in a lower loss rate that forces the return rate to approach 80 percent instead of such being a constant return rate like was initially assumed.

UNIDENTIFIED SPEAKER: Higher loss.

MR. TRAVIS: Yes, that's correct. Sorry. I misspoke. The losses are much higher in the short term. It starts at zero and asymptically approaches roughly 80 percent.

I'm going to turn it over to Tim to discuss the findings on the passive core cooling system.

MR. DRZEWIECKI: Thanks, Boyce. The last time we met we talked about how staff actually did the review for the passive core cooling system and what the staff's findings were. And how staff did that review was by looking at all the safety functions of the passive core cooling system and looking at what is impacted. And those functions that were impacted was core decay heat removal and then safety injection as well, or possibly safety injection.

And the staff's findings were that there was no impact on Chapter 15 analyses. However, there was an update to Section 6-3 which had identified a delimiting, non-LOCA event and then extended that event out to 72 hours. And that analysis showed that once the Chapter 15 criteria were satisfied, they remain satisfied for a period exceeding 72 hours. Those results were consistent with staff confirmatory analyses.

Additionally, staff made a finding that the condensate return rate was

sufficient to establish the 420 degrees Fahrenheit within 36 hours. That was demonstrated with a non-Chapter 15 analysis. That was also consistent with staff confirmatory analysis. Additionally, staff found --

CHAIRMAN RAY: Excuse me, just an editorial issue. Is there a reason you call it non-Chapter 15 rather than Chapter 19?

MR. DRZEWIECKI: That's just to confirm that it's the -- it's a non-bounding and conservative analysis. So we just call it non-Chapter 15 just to make it clear that it's not a Chapter 15.

CHAIRMAN RAY: I understand that. I am asking you why you didn't choose to refer to it as Chapter 19 as sometimes is done. Is there a reason for that?

MR. DRZEWIECKI: No reason.

CHAIRMAN RAY: Okay.

MR. DRZEWIECKI: And our last finding was the ability to establish open with cooling the ADS system was retained as defense-in-depth.

Next slide.

So now we're going out into the next portion --

CHAIRMAN RAY: One other thing I just want to clarify. You talk about a defense-in-depth. Usually I think of defense-in-depth as being different safety systems which are redundant to each other or which can back each other up. The close with cooling system doesn't have redundancy in it and therefore in order for it to be credited from the standpoint of having redundancy, the ADS is basically the redundancy that it would otherwise have. So I'm looking at the defense-in-depth and I'm thinking well, it isn't quite what I think of as defense-in-depth. Redundancy isn't defense-in-depth. It's redundancy.

MR. DRZEWIECKI: Okay.

CHAIRMAN RAY: But having made that comment it is different, the open loop is different than closed loop, so I understand you can refer to it that way as well.

MR. DRZEWIECKI: Okay.

MEMBER STETKAR: Tim, let me ask you one thing as long as we're on this slide here, and unfortunately, I don't know anything about thermal hydraulics and our thermal hydraulics folks aren't here, but I'll ask the question anyway.

In the SER, it talks about the confirmatory analyses you use for containment response using MELCOR. And in there, there's -- to me, it sounds a bit strange but maybe you can help me. It said that for the best estimate calculations, the MELCOR analyses showed a containment pressure 2 PSI higher than the GOTHIC analyses. For design basis calculations it was reversed. The MELCOR calculations were 5 PSI lower than GOTHIC and you said well, that's good because that means GOTHIC is conservative and they use GOTHIC.

Do you understand why the difference, depending on whether or not you use -- did you use different design basis and --

MR. TRAVIS: Ultimately, the MELCOR calculation we were looking at was with respect to the design basis calculation, using the design basis decay heat, design basis initial conditions. The containment pressure we got in MELCOR was, like I said, 5 PSI lower than what was arrived at by the applicant.

MEMBER STETKAR: I got that.

MR. TRAVIS: So for the best estimate analyses, MELCOR wasn't capable of making some of the same assumptions that the applicant used in GOTHIC in terms of -- because MELCOR uses a significantly less robust RCS model than what's used by the applicant. Whereas the applicant doesn't use the RCS in WGOTHIC, it's being passed a massive energy release from LOFTRAN.

MEMBER STETKAR: From LOFTRAN. Okay.

MR. TRAVIS: So that ultimately results in the -- the band on the MELCOR is lower when you go from design basis to best estimate.

CHAIRMAN RAY: Okay. Thanks. That helps.

MR. DRZEWIECKI: I'm moving into the next portion of our presentation in which we're going to talk about what has changed since the last meeting. And I'm going to talk about changes that were made to the calculations, the impact of the ambient heat losses on the RCS, as well as we look further at the ability to transition open loop cooling during an extended station blackout event.

And with that, I'll hand it over to Boyce.

MR. TRAVIS: Sure. And so this slide is discussing the calculation revisions that happened since we last met with the ACRS. I'm going to go through this briefly. I think the applicants kind of covered this pretty well.

The previous method as they indicated, four calculations with spreadsheet interfaces. I'm going to say there was some friction in between some of those interfaces that made the calculation not as clean as it could have been and so in their calculation methodology update, they went to something more akin to what was being used in the Rev. 19 of the DCE which involved a WGOTHIC containment response calculation that incorporated the loss spreadsheet into the wall losses in WGOTHIC in a LOFTRAN calculation and these two calculations pass back and forth containment. WGOTHIC calculates pressure and temperature in the containment. LOFTRAN calculates the decay heat output to the IWRST and the temperature of the reactor vessel that was used by the applicant in WGOTHIC to determine whether there was boiling or not in the reactor vessel cavity.

Ultimately, the revisions to the calculations didn't impact the staff's findings

with respect to the system performs for 72 hours and still gets to 420 degrees in 36 hours because ultimately the performance between the previous calculation and now increased slightly due to the correction as to modeling errors in WGOTHIC and a more, like I said, the removal of that friction between the calculations and the spreadsheets.

MR. SHACK: How did the iteration go? You do the WGOTHIC with the heat source and the IWRST, you start out with an assumed heat source. You do the WGOTHIC. You then go back to LOFTRAN, calculate essentially a new heat source for the IWRST?

MR. TRAVIS: That's correct. The applicant tried to use like -- I believe they called it like a bounding initial condition and then tried to converge on solution that involved a small delta between the iterative timed steps. To the point where they were no longer getting a change in the heat source and the containment response in those calculations.

MR. SHACK: How many iterations were involved, do you have any idea?

MR. TRAVIS: That I can't speak to. I would have to defer to the applicant.

MR. PFISTER: This is Andy Pfister. I think it was on the order of two to three. So we actually started with LOFTRAN first, as Boyce was saying, to give the maximum energy to WGOTHIC and then because -- we got good at it by the end.

(Laughter.)

We did it often.

MR. TRAVIS: So I'll move into a discussion of the ambient heat losses. So late last year, the applicant told us that there was a potential for a loss of subcooling in the RSC during a non-LOCA event if ambient heat losses were considered. Generally, ambient heat losses would be not a conservative assumption in a case like this because if you're losing heat from the RCS not into the IWRST, effectively you're cooling the RCS without putting that heat into the loss of inventory.

And so the assumption was thought to be conservative, but the fact that

ambient heat losses could result in a saturated RCS meant that the PRHR would be in a condition that we hadn't really looked at before. So the applicant evaluated the potential for a loss of subcooling. Ultimately, the RCS, if you assume realistic or conservative heat losses from the RCS, you will eventually lose subcooling in the RCS. And then the applicant also evaluated what the performance of the heat exchanger would be under those saturated conditions.

And staff audited that calculation and performed some confirmatory analysis to figure out what the effect of heat losses from the RCS would be, and going into more detail on the next slide.

So the primary heat losses through the RCS would come from the pressurizer. It's a very large surface. It's hot. Parts of it are uninsulated. And so those uninsulated services account for a little less than half of the heat losses from the pressurizer itself.

And so the applicant performed analyses to justify the effective heat transfer coefficient that would be applied to the pressurizer outer surface in both RELAP and LOFTRAN. The reason the applicant used RELAP was because LOFTRAN wasn't suitable for performing RCS or looking at RCS under a saturated condition. And so they went to RELAP which is a little more capable of doing that.

They found that -- they calculated an effective steady state heat transfer coefficient, to try and conservatively bound what would be expected. They did this for both what I'll call design basis to maximize the heat losses from the RCS and more of a better or best estimate heat losses for what would be a realistic expectation for the heat losses from the RCS would be. And the staff did some independent calculations. We arrived at numbers that are relatively consistent with what the applicant has and are supported by literature. And Tim is going to talk about those in more detail.

MR. DRZEWIECKI: Following from those last two points, the heat losses that

were used by the applicant for more than 50 percent greater than were calculated by staff in their confirmatory analysis.

Additionally, the multiplication factors that were applied to the through insulation heat losses were backed up by literature that pertained to the athlete as well as laboratory testing. Data had shown that through insulation heat losses would be about a quarter to a half of total heat losses through the pressurizer.

A significant portion of that heat loss is a convective air flow and that's expected to be substantially reduced during the station blackout because you don't have the fans blowing in that compartment.

Is there a question? No. Okay.

So the applicant's DBA analysis showed a system which they subcooled for a period that would exceed 72 hours. Therefore, there was no adverse impact on a Chapter 15 DBA analyses. That was also consistent with staff confirmatory analyses.

Likewise, there was no impact on the 420 degrees in 36 hours of analysis. However, the system did lose subcooling within 14 days. However, that did not have adverse impact on the performance of the PRHR heat exchanger. That was supported by test results from the APEX facility, station blackout tests that were run for the AP600 and for the AP1000. It was also consistent with staff confirmatory analysis.

So this next slide, it shows some of the results of staff sensitivity calculations which I considered on ambient heat losses. These ambient heat losses are actually much larger than what was used by the applicant. The graph on the right, obviously, has a larger heat loss. And what you're looking at is a pressurizer volume as a function of time over seven days. And so when you lose your subcooled margin, what happens is just a bubble that's in a pressurizer, shows up somewhere else. What you see in our analyses, as well as the applicant's analyses, is that you see voids form in the

top of the steam generator tubes in the loop that does not have the PRHR heat exchanger.

However, even with these large ambient heat losses, we still showed that the system stayed subcooled for a period exceeding 72 hours.

So other impacts on the loss of subcooling where there's an update to the FSAR as well as there was a revision to the criteria to establish open loop cooling. After staff had done their audit of these calculations, the applicant submitted a supplemental RAI response in which they had described all of the heat loss flow paths from the pressurizer, as well as the updated FSAR, to include the maximum heat transfer flow rate through the insulation.

Early on in the staff's review of this, we had asked RAI to try and clarify what were the criteria in order to establish ADS. And that last RAI response, it had updated that criteria such that if you power it to IDS divisions B and C, this would give you -- it's the power that you need in order to monitor the status of your plant. Hot leg and core make uptake level provides an indication that you could possibly have abnormal leakage. Thermal couple temperature and RCS pressure as this is indication of reactor core cooling through passive RHR heat exchanger. So staff found that these provided a diverse and reliable indication of adequate core cooling.

So this goes to another topic that staff had addressed as part of the mitigating strategies review for Vogtle Units 3 and 4. Staff issued RAI to address concerns over the equipment complication of the ADS IWRST injection and containment recirculation valves. So these RAIs were issued to Southern and those responses were endorsed by Duke.

What those RAI responses had demonstrated was that the equipment qualification enveloped for those valves in question were bounding for a 30-day event that would credit use of passive RHR. It also demonstrated that the IDS batteries had sufficient capacity in order to establish ADS late into an extended station blackout. It also demonstrated the ability to establish open loop cooling in the absence of any and all power.

So this next slide, it shows the analysis done by the applicant in part of the RAI response and this shows an EQ envelope as well as expanded containment conditions during an extended event that would use passive RHR.

So clearly, in a pressure plot it's bounded by the EQ envelope. However, there is a period in which the temperature is going to be higher in containment than what is actually covered by the EQ envelope.

So to resolve that issue, they did a scaling analysis using the Arrhenius Equation and they were able to show that the scaled EQ envelope does bound these containment conditions over 30 days.

MEMBER STETKAR: Say that one again?

MR. DRZEWIECKI: Okay, well, let me go to a backup slide to make this clear. So what I have here is obviously this period -- this is not bounding. So the scale of those graphs, slide 56, so those graphs were scaled to an equivalent time and temperature at 150 degrees and they showed that the EQ envelope, I guess, would go out to --

MEMBER STETKAR: Activation energy came from where to do this scaling?

MR. DRZEWIECKI: As far as going in to that calculation, we didn't actually go that far, but it was conducted. Perhaps that's a question for the applicant.

MR. PFISTER: Yes, can you go back to those graphs for a second?

MR. DRZEWIECKI: Yes.

MR. PFISTER: So what you're seeing in the graph on the right and the temperature plot, the red line is our equipment qualification temperature profile. And so that's a function of both our qualification requirements for our accident harsh environment, coupled with our qualification requirements for abnormal events. So we qualify our equipment inside containment for a certain number of abnormal events in addition to a LOCA, in essence, so for example, one of those

abnormal events is four hour IWRST, PRHR cooling; four hours of PRHR cooling and so many occurrences over plant life. And so the red line represents what we've qualified for within our EQ program. The blue line represents the expected temperature profile for a long-term PRHR, long-term PRHR event and we've actually extended it out to 30 days here. Theoretically, I think we could have cut it off at 14 days. We just did an Arrhenius Evaluation to show that essentially the energy under the curve in our qualification program bound that within our expected condition for a 30-day PRHR event.

MEMBER STETKAR: But to get the behaviors at the two temperatures you need an activation energy and that came from some experiments?

MR. PFISTER: To get the behaviors -- I'm not quite following your question.

MR. KINDRED: This is Tom Kindred from Westinghouse. That's correct. The activation energies are determined as part of the equipment qualification program that feeds into the development of the equipment qualification curve.

MEMBER STETKAR: You really do have the measurements of those things from experiments?

MR. KINDRED: That's correct. Either they are from experiments or they are available and we -- they're available from common materials that we use them to develop the activation energies for those components.

MEMBER STETKAR: Okay, fair enough.

MEMBER RICCARDELLA: So I think what you're saying is because the red curve is higher than the blue curve over that early region, it would be equivalent to a lower red curve out to a longer time. Okay. But that requires an activation --

MR. DRZEWIECKI: Correct.

MEMBER BROWN: For the uninitiated, go back to that again. So on the second graph, the red line is really above the blue line based on this little back and forth, based on some

scaling?

MR. SHACK: Think of it as using up a fraction of expected life and you use up different fractions of expected life at different temperatures and because they've got a whole bunch of life they've used up under the red curve at the early part, where they really haven't used it up in the real world, the expected life when you get after the longer time --

MEMBER BROWN: I got it.

MR. SHACK: -- is okay.

MEMBER BROWN: That's slight of hand.

MR. SHACK: All you have to do is believe in Arrhenius, that's all and fractions of light. But with those assumptions, it's clear as crystal.

MEMBER BROWN: That's why I never banked on it. Thank you. I understand what you do.

MR. DRZEWIECKI: So now I'm going into a portion in which we're going to resolve some of the questions that came out of the last meeting. The first question we had has to do with the modeling of passive RHR and so this question is as far as how that was done and what's the basis for it.

So there was testing that was done as part of the AP600 program and that testing included these three vertical tubes and it also included tube uncovery tests, uncoveries done at 75 percent, 50 percent, and 25 percent.

MR. TRAVIS: Just to go back to the last slide for a moment, we have some diagrams of the test facility, but they're proprietary. Were we to have a closed session in the afternoon, we could have addressed -- if the ACRS want to see them, we'd be happy to provide that slide either separately or in another closed session.

MR. DRZEWIECKI: All right, so there were questions raised during the review,

during the certification of the AP 600. And that included the applicability of this correlation to a C-shaped heat exchanger.

So to address those questions, staff asked Westinghouse to do a blind calculation for results from the Rosa Test Facility and they were able to match those sufficiently to resolve staff concerns at that time.

Additionally, there was a concern over the possibility of vapor blanketing some portion of the heat exchanger, so it was also addressed during the review of the AP600. It was deemed that that was not likely to occur. It was never seen in any of the testing. If it did occur, it was limited to a short-length near the inlet of the tube.

MR. TRAVIS: So in this slide, we're discussing some of the availability as to how the staff made its finding based on this time frame that's been presented by the applicant. The PCS, PCCS is required to keep the core cool for an indefinite period of time. That includes both the PRHR heat exchanger and the open loop cooling. And so the means to accomplish that vary depending on the time period. From 0 to 72 hours, the design basis is the design basis. The applicant has access to only passive systems and from the analysis you see in both from the confirmatory analysis and the applicant's analysis has demonstrated reasonable assurance that the PCCS will perform.

For 72 hour to 7 days, the applicant has access to RTNSS B systems. For the purposes of what we're talking about here, this is really limited to refill of PCCS/WSC for the passive containment. So the tank on top of containment is required to be refilled. They have on-site pumps, equipment to fill the tank to an inventory sufficiently that they can continue dripping water over the outside of the containment shell.

In addition, there's some batteries required to provide power to the bravo and charlie monitoring equipment and plant operation. And so under best estimate assumptions, they continue to perform at least out to seven days and that's the extent of the staff's finding.

Past seven days, off-site support is presumed to be available. And in all scenarios, whether it's before seven days, after seven days, the plant retains the ability to transition to open loop cooling so they can pop ADS 4. The core main is covered. In the VCD it says indefinitely. It's staff's understanding that is until containment make up is required which is roughly 30 days.

MR. DRZEWIECKI: So there was a question on the meaning of safety at design basis. And this is really just a part of the design basis, as a subsection of the design basis in AP1000 at DCD. And other functional requirements that are called out as part of the safety design basis are nearly all demonstrated with a Chapter 15 safety analysis with the exception of the ability to reach 420 degrees Fahrenheit within 36 hours.

So the requirement of reaching 420 within 36 hours is still part of the design basis. It's left unchanged. The updates to the FSAR are there to try and clarify that requirement is to be demonstrated.

CHAIRMAN RAY: This is part of the frustration, I guess. You refer in the second bullet, first line to the safety design basis. And you say that's done in accordance with Chapter 15 which is correct. And then you say with the exception, now presumably that means with the exception that a safety design basis of 420 and 36 hours is done in some other way. Are you labeling the 420 and 36 hours as a safety design basis?

MR. DRZEWIECKI: I'm just saying as part of the design basis, if you go into Rev. 19 of the DCD --

CHAIRMAN RAY: Yes, but listen to my question. I understand it's part of the design basis. I'm asking do you mean it's part of the safety design basis demonstrated through Chapter 15? No.

MR. DRZEWIECKI: No.

CHAIRMAN RAY: Okay. When you use that label, safety design basis, you

know, it means something different potentially than just design basis.

MR. DRZEWIECKI: Yes.

CHAIRMAN RAY: Okay. Go ahead.

MR. DRZEWIECKI: There was a question on the application of GDC 34, how we apply for this review. And this showed up really as part of that design basis of extension calculation. And that was that the IRWST should be sized such that Chapter 15 design basis analyses should be satisfied for a period of at least 72 hours and that means reaching sub-criticality, decay heat removal, every activity in containment. In this case, that means your acceptable fuel design limits are not challenged to the pressure boundary.

And the second bullet that events exceeding 72 hour duration are not considered a Condition 2 event. And the reason why I'm saying that is that if you had to rely on the ADS system after 72 hours, that may be considered an event on escalation. However, because it's happening during late into this event, that's not going to be considered by staff and AOO. So we have asked them to find what's the limiting event in terms of PRHR performance and to extend that out 72 hours which they did.

MR. TRAVIS: So to conclude for the technical evaluation, the updated calculation methodology as presented by the applicant doesn't impact the staff's previous findings, that Chapter 15 analyses are not impacted or affected and that the passive core cooling system is still capable or is capable of cooling the RCS to 420 in 36 hours.

The consideration of ambient heat losses doesn't adverse impact the Chapter 15 analyses. In fact, it would likely help them in the short term. And a loss of subcooling is not expected to occur within 14 days or -- sorry. Loss of subcooling is not expected to occur within 72 hours. It is expected to occur within the first 14 days. The applicant has demonstrated through analysis and test data that the performance of the heat exchanger doesn't degrade and ultimately the

transition to open the cooling via ADS4 is retained as a defense-in-depth mechanism.

And with that, I'm going to pass it over to Tom to discuss some of the vendor inspection.

MR. KENDZIA: So first time I've ever been at the ACRS, the head of this vendor inspection retired when he heard he had to present.

(Laughter.)

The assistant lead went on inspection for a week. So I'm the third stringer for you.

All right. So NRC vendor inspection, what do we do? What we do is we look to see that people are following the requirements of Appendix B and Part 21 and we do that by doing technically-focused inspections. So we try to focus our inspections around technical issues to see how they're implementing the requirements of Appendix B. Appendix B is your quality assurance program requirements.

So did any of you have a general question on that? Good.

NRC inspection. We did that in January 26th through the 30th, 2015 at the Westinghouse Cranberry facility. And we took along technical experts to ensure we were correct. Tim was there and Anne-Marie Grady was there and we went through the technical expert. We were looking at this inspection from the standpoint of condensate return issues and the hydrogen vent issues and then some other aspects of their quality assurance program related to audits and internal and vendor supply lists.

Now what we found is is that we issued two notifications of nonconformance. A notification of nonconformance is where they have not conformed with the Appendix B criterion associated with -- that's required of them by the purchasers. In other words, they have a purchase order issued to them saying you've got to meet the requirements of Part 21 and Appendix Bravo.

Appendix Bravo has certain requirements. They were not meeting those requirements, so it's a notice of nonconformance with the purchase order. That's versus a violation. If it was a violation, if they were not meeting the requirements of a Part 21, Part 21 directly applies to the vendors and therefore that would be a notice of violation. So that's a difference between a notice of nonconformance and notice of a violation.

All right, so we issued a notice of nonconformance for Appendix B criterion 16, corrective action. And they failed to promptly correct conditions adverse to quality. Failed to promptly identify and correct conditions adverse to quality and for significant conditions adverse to quality, they failed to take action to prevent reoccurrence.

We had four examples where we went through in their corrective actions. They were all associated with significant conditions adverse to quality that they did not meet those requirements. One was with the control of the vendor of the safety related supplier list for them. They had vendors supplying safety related products that were not covered by what they had qualified those vendors to do. One was associated with a root cause evaluation. They performed and found significant conditions adverse to quality associated with a fuel assembly supply to Indian Point. I believe it was Indian Point. I'll double check. Yes, Indian Point 2. And they did not take adequate action for that. One was associated with internal audits.

When the internal audits identified gaps and what they were -- in other words, there's lots of different places that Westinghouse does work. And their internal audits would be required to cover each one of those locations for those aspects since they're doing that type of work. And they did not provide full coverage for those aspects.

And the last one was to do with the condensate return. And the condensate return, it was identified to them through a technical question that there was a question on the adequacy of the return assumption in 2010. They did not write a corrective action. They've changed

the name a number of times. I think it's CAPAL now, yes. But a corrective action report. They did not initiate one for two years after the technical question was identified. And then when they did issue one, they didn't classify it as significant condition adverse to quality which we determined that it should have been. And they concurred with that in their response. So that was the four examples associated with the Criterion 16 nonconformance.

As you see here, I wasn't reading from the slide. I apologize. I worded that the same, but go to the next one here.

All right, so the other examples, we already talked about those. And then we issued a notice of nonconformance for Criterion 1 organization. And this had to do with the fact that there was portions of the QA program that they hadn't been effectively implementing and by not effectively implementing, it actually indicated to us that it was more a failure of the management at a higher level than just at the implementation for procedure.

So we raised that up to a notice of nonconformance against organization, Criterion 1. That's what we would do if we think it's more programmatic than just specific individual events.

And those examples had to do with the control of purchase of material and services. The problems with corrective action also helped influence us to say that was more organizational. In their corrective action, the NRC -- well, when we issue these reports, they have 30 days to respond. And in that 30 days, they come back and either respond or they provide a reason for an extension. They came back with their first response and every response we look at to see if it adequately addresses the issues. And in this case, we had questions on it in relation to the organizational issue and the corrective action they were taking there. So we sent another letter to them request for additional information. And then they responded a second time and provided that additional information.

So you can see here that they provided -- they got the report, then they provided the first letter on May 20, 2015 and the second one was July 16, 2015. And between the two responses, we found their responses to adequately address the issues.

In this case, what that meant was like for the corrective action one, they said hey -- I'll take this specific example. They had to address each specific example and the generic problem. So for the generic issue of corrective action, they were addressing the aspect of -- we're going to do a self-assessment. We're going to identify these different issues and then we're going to take corrective action. So that action is not complete at that time, but that's what they're going to do.

Then for the condensate return issue, they said they were going to look at the -- they were doing the extended condition, looking at all those different requests for information and figuring out the extent of condition, what else they needed to do. And they were also going to look at, do a root cause on the condensate return issue. And then they were going to look at the further extent of that and make sure they were addressing all the pieces and then after -- late 2015, they were supposed to complete a self-assessment of all the corrective actions and their effectiveness.

So tentatively, what we have scheduled is a return inspection in the fiscal year 2017 to look at their effectiveness of taking this corrective action. We always try to give them enough to make sure they fully implemented their corrective action. Because if they're still in the process of implementing corrective action, we can't write them another violation at that point, whereas if they've implemented the corrective action, then we would issue them another notice of violation if it wasn't effective.

MEMBER STETKAR: Tom, this is Fiscal Year 2017. Is that plan for this calendar year or --

MR. KENDZIA: It was scheduled for the -- you would say the fall -- the first quarter of 2017 or fall of 2016, yes.

MEMBER STETKAR: Okay, thanks.

MR. KENDZIA: Fiscal year runs to September.

MEMBER STETKAR: I was trying to figure out whether it was third quarter calendar year 2016, '17.

MR. KENDZIA: One thing to point out is is that with the Westinghouse, we're doing a number of other inspections there all the time, so that we're constantly monitoring Westinghouse performance and their effectiveness of taking corrective action on things. So we're not leaving them just totally alone until we go back to see if they've done something effectively. We have indications, we have lots of different inspections there. We're still inspecting a lot of stuff associated with the I&C systems.

MR. HABIB: I think that's the end of the staff presentation.

CHAIRMAN RAY: Okay, so we're at the end of the presentations on containment -- I mean condensate return. And before we go to the other four topics, are there any questions anyone wants to ask that either pertain to, for example, the last discussion, is that more broadly applicable than just condensate return.

MEMBER SKILLMAN: Harold, I do.

CHAIRMAN RAY: Go ahead.

MEMBER SKILLMAN: Tom, I'm interested in why I&E would be comfortable with other inspection activities as being, if you will, a surrogate for what are clearly some design issues here. You said other inspections are ongoing and I'm well aware Cranberry has an awful lot of very sophisticated and important activities. So I don't doubt for a minute that there aren't a lot of inspections. But why should we take comfort in other kinds of inspections when we're really focused here on at least what we consider to be some very important issues pertaining to the authority and the accuracy of this design control document.

MR. KENDZIA: I understand your question. Now for the condensate return issue, we're not totally satisfied ourselves from okay, we're going to go look later. The technical staff is actually involved with the resolution of these issues and following on those issues to make sure that you're answering those questions.

So we have -- that's part of our equation for figuring out when we go back. So if technical staff wasn't doing anything, then we probably would be back already. And we would not normally go back until they were done with the corrective action because if it's in process, then from the vendor inspection standpoint, it would be more like consulting that they're going in the right direction and we don't do that from the inspection standpoint. We write notice of violations or notice of nonconformance for not meeting the requirements. If they're in the process, we don't give them advice on how to finish the process.

The technical staff was actively involved with these issues. We had -- the other issues we determined through our review that it was not an overriding safety concern or that would be a different level of -- we're talking about for the fuel assembly. That was discovered by the licensee. In turn, that issue was addressed that way. It was the aspects of not fully controlling who they were purchasing things from, from a safety-related verified and they were able to do the safety-related aspects in accordance with their program requirements and ours for audits and stuff that wasn't being met. So we were concerned with that aspect. And they provided what they were doing with a time schedule, how they were going through their whole QSL. That's their qualified safety vendor list. I think it was QSL.

But they're going through -- there was a time frame for that and they had categorized the different services they were procuring based on risk and they were doing the highest risk ones first. So we looked at those aspects.

CHAIRMAN RAY: Tom, let me interrupt for a second. I don't know that you can

answer this question, but let me ask it anyway. Can you describe -- normally it's not thought of as inspection when you look at a program that's being implemented in the design development of a reactor for certification. Can you describe what was done by the Agency to validate the programmatic requirements that were implied during the design phase of the AP1000?

MR. KENDZIA: We did do it. We have a set inspection for design applicants that we go through and look at their QA program. We look at those aspects related to the design certification. And part of that would have been engineering. And that was before my time with the NRC. I had a prior career before here. But what they would be required to do and I've done this inspection actually at NuScale recently. You would go through and you would verify those parts of the program such as their engineering program would have independent reviews built into it. You'd verify that the independent review process was actually independent and not --

CHAIRMAN RAY: Okay, I understand that. All right. But you don't know to what extent it was done back before like I say the certification was issued for the AP1000?

MR. KENDZIA: Not for Westinghouse. I do not know. I don't know if --

CHAIRMAN RAY: I mean that pertains to what we're trying to understand here perhaps, which is how it would be that now with such clarity the problems are recognized, but they weren't at all -- Criterion 3 for example and things like that. There has to be occasions where you learn some lessons and I'm asking what are the lessons that we learned from this experience and that would mean we're talking about a period of time years ago when this design work was done.

MR. KENDZIA: We're looking at design organizations and engineering-type activities. We'll look for are the people qualified? Do they know what they're doing? Do they have the documentation?

CHAIRMAN RAY: But I'm asking specifically in this case, okay?

MR. KENDZIA: I'll get to that. Then we look at corrective action. One of the

aspects of corrective action that you have to be careful about is this identification of conditions adverse to quality. If you go to vendors, there could be 10 or 20 different places that they can identify this. it could be on customer questions. It could be on customer returns. It could be on purchase order requirements changes. So you have to look at all those processes and determine are they going through and screening those processes --

CHAIRMAN RAY: I understand. I'm not asking you to describe what you do. There are 18 criteria in Appendix B. I'm just asking was there an inspection that failed to identify the problems that we now identify that was performed during the time when this design work was being done prior to certification. That's the question. Because afterwards, you have customers and they're providing oversight themselves. But there is a point in time when it's only us. And that's the question I'm trying to get answered, not what are all the things you do because I know what --

MR. KENDZIA: I'll ask Greg to speak to that because he may have been here.

MR. GALLETTI: This is Greg Galletti from the vendors inspection staff. Way back, when we first got the DCD for review, we did a couple of things. One, we did an audit at the time using vendor inspection folks and our technical folks. And really that audit went back to what Tom was addressing, looking at the Appendix B criteria, as far as how the DCD itself was developed and looking, working with the Westinghouse folks, with their technical staff, understanding the types of analyses and efforts they had done to get to that level of the design of the DCD.

Since that time, we went back I think in the 2010-2011 time frame, and we did what was called an engineering design verification. And in the EDV process, there's a process, a vendor inspection procedure that we go through and in that, again, the design is a little bit more mature at that point, so we try to go in and sample certain aspects of the design, looking at how they do their calculations, look at how they do their design control, and as a result of that inspection we did not see this issue.

I don't believe since the 2011 time frame other than the vendor inspection that Tom is talking about that we specifically looked at this condensate return issue from a vendor inspection point of view.

MR. KENDZIA: Now the condensate return issue did point out that what was missed here from our perspective and Westinghouse concurred was when they got the question, they didn't properly classify. So as part of the extended condition, they were looking at that. So when we go back and reinspect, we'll specifically look to their adequacy of how they went through the extended condition for that program of customer questions or licensee questions to see how they've -- if they've done that adequately at this point. That would be part of the reinspection.

CHAIRMAN RAY: Well, again, that's after the fact. The objective, of course, is to avoid the problem in the first place. And you do that by ensuring that there's an effective program that's working when the design work is done.

I would be surprised, as I say, if anyone here could on the spot call up what was done back when the design work was done that was then determined to be in err to see what it was that was saying Criterion 3 that wasn't done correctly. And should have done -- testing that should have been done that wasn't done, for example, not just independent review. But it is, nevertheless, the -- if there's any lesson to be drawn out of here, it would be at that point in time, what confidence -- you talk about NuScale, for example.

What confidence do we have that the program being implemented by NuScale, and I don't want to go into that at all, but it's just simply an example that was raised, has all the attributes that are necessary to avoid this sort of thing ten years from now surfacing?

MR. KENDZIA: Well, as part of our process, you know, that is the question of how -- first of all, you always have to learn from where you didn't find something. And we do training on that every quarter. And we cover some things to that. Another aspect though is that one of those

areas that you have to look at is how you're handling -- how is the applicant going to handle questions from the licensee, from the regulatory authority or other countries' regulatory authorities? They should have a process for that. And we should be looking at that. So that's an aspect that if we don't feel the procedure is current, our procedure is currently adequate to cover it, we will train on it and revise it.

MEMBER RAY: Okay. Well, unless there's something specific to what we're pursuing, we probably should move on. But go ahead, please.

MR. JACKSON: Okay. This is Terry Jackson, Chief of Quality Assurance, Vendor Inspection Branch 1, and I think kind of what the staff is trying to convey is that, when we did the initial inspections and so forth, it is a sampling process when we look at the program. Sometimes, programs can look good on paper, but the implementation may be of issue. So we take things away from maybe the AP1000 experience is may be some of the aspects of like looking at operating experience that may come from international and so forth when we do our inspections and maybe pull some of those samples when we do inspections.

But the chief thing is that we are sampling. And the other idea that we're trying to enforce, and I think this is something that has been something the NRC has been able to do is that, in

this case, the vendor has a primary responsibility for safety with the activities that they're doing. The licensee and the customers, they have a primary oversight responsibility for their vendors. And so we're trying to encourage that, that the licensees are engaged with their vendors and providing the adequate oversight.

MEMBER RAY: Yes. Well, that's certainly true and it's always been true, but I'm talking about when you're pre-certification, the ultimate customers may not yet be fully engaged, and the only oversight being provided, therefore, is the person certifying design, and that's this agency. The customers don't certify the design.

MR. JACKSON: But they are using them as a vendor eventually, so we are --

MEMBER RAY: Eventually, but not at the time, necessarily, not at the time. We shouldn't pursue this any further. I just want to, I understand your response. I'm only trying to say that if you're looking to the customers of the vendor of the certified design to ensure quality during the design process prior to certification, okay, that seems to me like maybe a problem that we

can discuss some other time. Thank you.

MEMBER BLEY: Since you've talked about this so much today, Harold, I thought I wanted to throw in one little thing on the record. It kind of brings up what are you buying when you buy a design that's been certified by the NRC?

MEMBER RAY: That's right. And I don't have any automatic answer here, Dennis. It just seems like this is an opportunity to explore that question and to determine what the expectations should be for customers of a vendor of a certified design relative to the development of that certified design. Should they assume the agency has done everything that needs to be done or not?

Okay. Back to you, Don.

MR. HABIB: I think we've completed our presentation here.

MEMBER RAY: Anybody else have any other questions at this time? Now, again, we've got four other departures to go through. It's getting mid-afternoon here, so we want to move on.

Okay. Hearing none, then we will first, again, hear from the applicant, the remaining four exemptions, if I can get my story straight, and

then, finally, from the staff, and that will conclude the day. We'll take a break in between those two things.

Larry, are you in charge?

MR. TAYLOR: I'll be driving again, and I'll cover two of the topics.

MEMBER RAY: Okay.

MR. THORNTON: Good afternoon. I'm Jim Thornton. I'm a licensing manager in charge of the AP1000 projects at Duke Energy.

MEMBER RAY: And you have your microphone on I trust, yes?

MR. THORNTON: It's a green light, yes.

MEMBER RAY: Thank you.

MR. THORNTON: I'll describe the generic issues associated with the AP1000 main control room dose analysis and what was done to resolve the issues. I have Aaron Wilmot of Westinghouse here to help address any questions you may have. Aaron performed many of these main control dose evaluations.

Next slide. Beginning with some background, the post-accident dose criteria for the AP1000 main control room are satisfied by crediting

the safety-related emergency habitability, or VES system. The main control room operator dose evaluations and results are presented for a wide range of design basis accidents in Chapter 6 and 15 of the DCD.

Subsequent to AP1000 design certification, deficiencies in the design basis main control room dose evaluations were identified. These deficiencies included not accounting for direct dose contribution for radioactive material accumulating on the VES filter, which is located inside the main control room. This oversight affected main control room results for all the design basis accidents addressed to DCD.

A second deficiency involved not modeling the most limiting steam release rate scenario, the main steam line break accident. This error impacted only the main steam line break accident.

A third deficiency involved not conservatively accounting for AP1000 design details in direct dose shielding calculations. This impacted the large break LOCA analysis for the results reported for the main control room in the

DCD.

I should just add that all these deficiencies really were control room related. They did not relate to the off-site dose calculations results reported in the DCD.

In order to address these deficiencies, a combination of design and analysis changes were implemented to demonstrate that GDC-19 dose criterion was still satisfied by the AP1000 design.

Next slide. This slide summarizes at a high level some of the changes required to address the AP1000 main control room dose analysis deficiencies. First, as part of a new assessment of the direct dose contribution from the emergency ventilation system filter, radiation shielding was added around the filter in order to reduce the calculated direct dose contribution to the main control room operators.

Next, modifications were made to the main control room ventilation system control set points in order to align filtration and emergency ventilation more rapidly, thereby reducing the operator airborne exposure contributions. There was also a reduction in the technical specifications

secondary side coolant dose equivalent iodine concentration limit for normal operation. The tech spec limit was reduced in order to offset the effect of the more limiting steam release rate applied in the evaluation of the main steam line break accident.

Changes were also required to correct the shielding calculation models and accurately reflect the AP1000 detailed design. The shielding model changes had a net effect of increasing the main control room dose component for direct dose applied to the large break LOCA analysis.

Next, there was a need to update the rod ejection analysis methodology to satisfy an AP1000 FSER requirement. The AP1000 FSER requires that the updated standard review plan Section 4 guidance be applied if changes to the AP1000 rod ejection evaluation turned out to be necessary. Application of the updated guidance resulted in larger fuel release source terms and calculated radiological consequences for the rod ejection accident.

Finally, there are a number of other refinements to the dose calculation inputs and models to account for AP1000 detailed design

updates. Examples of revised inputs include the main control room volume, main control room ventilation system flow rates, and containment service areas. These all just resulted from detailed design calculations and updated refinements in those values, and they were implemented when --

MEMBER SKILLMAN: Jim, I'd like to ask you, you introduced your topic here by saying these changes just affect the control room. Wouldn't the reduction in the DEI also affect off-site?

MR. THORNTON: The rod ejection accident?

MEMBER SKILLMAN: No, dose equivalent iodine.

MR. THORNTON: Oh, they did. It would have been a reduction for the main steam line break.

MEMBER SKILLMAN: So it would affect more than the control room.

MR. THORNTON: But in the sense that the main steam line break accident, you had two cases that were being evaluated, and this was the reason for the change in the main control room. And I can ask Aaron to explain it further, but it was the mass release rate versus total mass. For off-site, total

mass continued to be bounding, and that's what was originally assumed in the main control room analysis. And then they discovered, based on the main control room ventilation system design, that the other case where you maximize release rate but released a smaller mass, that ended up being bounding for the main control room.

So I apologize if I was misleading about the impacts to off-site. In that particular case, it results in a net reduction to off-site doses.

MEMBER SKILLMAN: Okay. Now I understand. Thank you.

MEMBER RAY: Well, you said these changes occurred as a result of detailed design, I believe.

MR. THORNTON: Many of them, yes.

MEMBER RAY: Yes. Do you think that's going to be typical as we go through this sort of thing? In other words, does the design certification contain a lot of details in it that inevitably are going to change as the detailed design develops, or should these changes have not been necessary?

MR. THORNTON: I can answer that. There

are a lot of design changes that are occurring through not only the license amendment process but the licensing change process. Those that don't, you know, they call them design change proposals, and there are several hundred of them. So those all reflect detailed design updates. I can let Westinghouse continue with that explanation.

MEMBER RAY: I'm just trying to figure out if there was something amiss, other than, well, we haven't done the detailed design yet and this is what we should normally expect. I've gone through Part 50 licensing, so this looks like just normal stuff that happens --

MR. THORNTON: Design evolution.

MEMBER RAY: -- before you apply for your operating license. And I'm just trying to learn something here, other than just yes, yes, yes, we've got to make these changes because they're logical and they make sense, or is this stuff that was supposed to be avoided somehow by a more rigorous design process? You know, I don't have an answer to that, but it's a question --

MR. THORNTON: I think in this situation it's a mixed bag. Those things that caused us to

have to essentially report the deficiencies and fix them prior to licensing COL for the Levy plant, I would put in that bag of, yes, these are things we should have avoided prior to certification.

Some of these other design updates that were included in these analyses just happened to be processed and ready to implement when they were re-doing these calculations. So --

MEMBER RAY: All right. A mixed bag is probably a good way to express it because, once you're going to make some changes, you might as well make all the changes that look like they --

MR. THORNTON: Those three deficiencies that I started the presentation out with were the key ones that tripped ISG-11 and forced us to address these now, rather than later.

MEMBER RAY: Okay. That's satisfactory. Westinghouse wants to make a comment.

MR. HARPER: Good afternoon. This is Zach Harper, Westinghouse licensing manager. I just wanted to follow on on what Jim was saying is that, you know, we do have many design changes that have come out, you know, through the detailed design. A lot of those design changes is a result of having a

lot of detail in the initial design certification. It's the nature of Part 52 where we have a license prior to performing construction. We do find that we will find several design changes out of lessons learned from start-up testing out of China. We have changes that we'll find based on, you know, procurement, we can't get the part that we originally thought that we were going to have just because of the nature of having a certified design several years prior to building the actual plant.

So, you know, to answer your question, yes, I think this is a natural part of building the AP1000 and other plants, as well. And this is expected to see some design changes coming out of a detailed design process.

MEMBER REMPE: So I'd like to follow up on how often you decide to re-do all of the calculations to see if you've tripped a threshold because I think earlier in some of the discussion there was an adder put in to try and avoid, I assume, to trip things. But how many changes because of procurement or whatever have to occur before you say, well, we better re-do a lot of these calculations? What's the process to ensure that

you've not come up against something else and you need to come back here or do something --

MR. PFISTER: Excellent question. So this is Andy Pfister from Westinghouse. There is no singular answer of magic time. What we have to do is address each change as it's developed.

MEMBER REMPE: So you do address each change now?

MR. PFISTER: We, I'll say evaluate each change as it comes up and understand what is both the singular effect of that change and what is the cumulative effect of that change and with consideration for other items. So, for example, one of the items that I'm responsible for is delivery of the safety analysis. We had a safety analysis that supported Rev. 19 of the DCD, and that was largely unchanged from the Rev. 15.

In 2008 time frame, you know, we went through the process of developing what we call AFCAF or the core reference report to support the first core, which was submitted as a generic topical that was just approved in 2015. As part of that effort, we said now is a prudent time to introduce and to reconcile the culmination of lots of small design

changes into the safety analysis. And so I'll say, in essence, we took our safety analysis that was 2005 or older vintage and reconciled it to a 2008 design reference point. And just recently, in 2015, we've said, you know, we essentially finish detailed design, and we've done that once more, and certain change packages the staff is going to be seeing from the licensees will come and bring the cumulative effect of those changes in the form of departures or license amendment requests.

When we go through and evaluate those, we look at them from a Duke purpose, you know, from a Levy purpose that says do these change conclusions, do these trip ISG-11? So we're looking at them from two perspectives, you know: implementation for the licensees, as well as impact on the applicants. And as part of that assessment for impact on the applicants, these are the five items that trip that criteria as needing to be implemented within the application, as opposed to being deferrable to later.

MEMBER REMPE: Thank you.

MEMBER RAY: Okay. Let's move on.

MR. THORNTON: Okay. The next slide, in

summary, the revised main control room safety analysis continues to apply conservative design basis accident source terms and assumptions and preserves margins relative to the main control room operator dose acceptance criteria.

AP1000 design and methodology changes were applied to more than offset the effect of non-conservatisms identified in the original AP1000 safety basis. This is illustrated by the results for the large break LOCA, which have been reduced from 4.41 to 4.33 rem TEDi.

In addition, the normal main control room HVAC system was demonstrated to continue to be capable of functioning as a defense-in-depth system to limit main control room operator exposures to within the GDC acceptance criteria.

And that's, essentially, what we had prepared today to discuss on the main control room dose, and we're prepared to answer any additional questions.

MEMBER RAY: Any more questions on dose to the applicant? All right. Move on to the next item then.

MR. SCOBEL: Good afternoon. I'm Jim

Scobel, Westinghouse. I've been involved in AP600 and AP1000 severe accident issues pretty much since the beginning of time. So we're here to talk about hydrogen venting inside containment.

This is a severe accident issue. This is definitely beyond design basis Chapter 19 stuff. And as you probably know, AP1000 employs containment hydrogen igniter system inside the containment. We call it the VLS system, and it's intended to burn hydrogen as it's released from different locations inside the containment and to burn the hydrogen at lower flammability limits to keep it from accumulating inside the containment. And part of the strategy, as well, is that the containment layout includes vents at the top of all the compartments through the ceilings, which become floors in other compartments, to release the hydrogen so it doesn't pocket anywhere, accumulate somewhere where you can get a large concentration and to keep the hydrogen mixing through the containment.

So there are several rooms that are located below the core makeup tank level, which we call Room 11300, and these are the PXS and the CVS

compartments. They're small compartments, dead-ended compartments below that floor that have, they have the PXS squib valves, injection split valves, recirculation squib valves are located there. The direct vessel injection line is located in this compartment.

And so if you were to have a double-ended break of a direct vessel injection line in that compartment, you could potentially have a hydrogen source from the reactor coolant system. If you were to have a severe accident, contingent on having core melt, you could have a potential for hydrogen to be released from the DVI line into the PXS compartment and then up into the CMT room.

So this is fine. The hydrogen will come out, and there are igniters located in this location. But there's also, in this location, there's the equipment hatch, the containment shell is located further away, and so we have to make sure that a potential hydrogen burn locations do not potentially threaten the containment pressure boundary.

Anyway, there were some design changes that were implemented to the containment layout that

did not alert the hydrogen diffusion flame analysis that was performed that these changes had occurred. And this was identified by an ITAAC review that Westinghouse was performing that showed that we had changes to the sizes of the vents that brought into play an opening that was closer to the containment shell than the ITAAC allowed.

So this is for one particular severe accident scenario, which would be the double-ended DVI line break. That would also include failures of the ADS valves that would cause hydrogen to be delivered to the location in the PXS compartment where it could come out and burn above that floor in the CMT room.

Now, I should also mention that the ADS valves themselves are situated such that in a more likely severe accident scenario the hydrogen is not released to this location, it's released to locations where it can burn and it will be shielded, the containment shell will be shielded from the burn or the burns will be located farther away from the shell. So this is like a less-dominant severe accident scenario with a frequency of 6x10^-9.

Okay. You can go to the next. Okay.

So this is the layout that we're --

MEMBER CORRADINI: Can I ask a question? We're talking deflagrations. In everything you've just discussed, we're talking deflagrations.

MR. SCOBEL: We're talking diffusion flames.

MEMBER CORRADINI: Diffusion flames in all cases. So why is the, why is the distance from the containment shell an issue for a diffusion flame? That's where I was leading.

MR. SCOBEL: Okay. Well, I'm kind of getting to that. In the original layout, you can see that this is the PXS alpha location, and in the upper left-hand corner you can see the original layout included a large vent along, that's the refueling canal wall there at the bottom. And so the vent from an 11 to a 6, which is the PXS compartment below, was releasing along that wall. And the analysis was performed assuming that diffusion flames were vertical cylinders, so you were radiating, you had a radiation view factor that was affected by the distance of the vent to the containment shell.

In the final layout, as you can see,

they've made the vent smaller, which is what brought into play the core makeup tank. Where that circle is located, the core makeup tank actually sits on top of that, and the penetration for the discharge pipe goes through that floor. And so there's a small vent there. It's approximately three square feet, but, because of the way the ITAAC was worded, we had to consider that a hydrogen vent, and it was located closer to the containment shell than the ITAAC permitted.

MEMBER CORRADINI: So are you saying -- I'm not there yet. Are you saying, from a process standpoint, what you want to build and what you thought you were going to build are different, so you've got to re-analyze, or are you saying there's a real issue?

MR. SCOBEL: I'm saying we need to re-analyze.

MEMBER CORRADINI: Okay.

MR. SHACK: Before you go on, you do an analysis for two plumes, as I understand the way the analysis goes. Where are those plumes located in here?

MR. SCOBEL: Well, that's another good

question. So given the nature -- well, okay, there's another point I want to make before we go on to the next slide, and that is, okay, in the original analysis, the place where the hydrogen was coming out was located away from the containment shell because the vent in the ceiling of the CMT room was located away from the containment shell. Now they've added this notch that is actually along the containment shell, which allows the equipment hatch to open. There's a hoist above that, and there's a notch there along the containment shell, and it needs to be there for the equipment hatch to get hoisted up.

So this is a much more complex configuration than what we were analyzing previously, so -- okay, you can go to the next slide. So the analyses that we needed to do to support this change to the analyses, first, we needed to look at the hydrogen source term for the containment. So we performed a matrix of MAAP 4 runs looking at double-ended DVI line breaks with a matrix of all the different combinations of ADS valve success configurations that you could have in order to determine the maximum source term, the

worst hydrogen source term that we could deliver to that location.

And then, because of the complexity of the configuration, we did a CFD analysis of burning plume, and we looked at hydrogen coming from both vents, one vent, the other vent. We did a sensitivity study on the flow split between the vents, and, basically, what that did was it identified that these layout changes, including that notch, had introduced a new phenomenon to our hydrogen burning scenario, which was that the plume was actually drawn closer to the containment shell. So the view factor no longer was related so much from the distance of the vent, as you were saying, but it's related to where the plume was being drawn to the ceiling.

MEMBER CORRADINI: Along, literally, the shell wall.

MR. SCOBEL: It was being drawn to the containment through that notch. So in order to address that heat-up and to kind of get away from having to defend CFD analyses, which can be particularly difficult when you're employing combustion modeling into your plume, we employed a

simple hydrogen burning plume model, basically a heat balance over the plume, assuming perfect mixing of the stoichiometric mixture of air and hydrogen, to come up with a plume temperature and then performed a containment pressure boundary heat transfer analysis of the containment shell, the equipment hatch cover, the hatch barrel which is where the --

MR. SHACK: But that plume went through the notch?

MR. SCOBEL: Yes.

MR. SHACK: Now, where did the second plume go? It only seemed like there was one logical place to put it, and that was --

MR. SCOBEL: We did it as a 1D analysis coming from the worst case that we found from the CFD analysis, which was from the hatch. But in the 1D analysis, we looked at it coming from the hatch or from the CMT hole, the penetration hole.

MEMBER CORRADINI: Can you go back a slide?

MR. SCOBEL: Yes, sir.

MEMBER CORRADINI: So just so I'm on the same page, it's the notch in --

MEMBER RAY: Turn on your mike, Mike.

MEMBER CORRADINI: So in the square above Room 11300, the notch is where you're assuming the flame is going through.

MR. SCOBEL: That's correct.

MEMBER CORRADINI: So I guess --

MR. SCOBEL: The CFD analysis showed that --

MEMBER CORRADINI: So even though you've got the big square, it wants to go along the wall?

MR. SCOBEL: Yes.

MEMBER CORRADINI: And so what did you do with the big square? You just ignored that -- okay. That kind of answers your question.

MR. SCOBEL: Yes. Sorry, I did not understand that that was your question.

MEMBER STETKAR: We have pictures of the CFD calculation as a backup slide to the NRC, but there were no pictures of the plume.

MR. SCOBEL: That's correct. So we really focused on the 1D calculation once we had identified that we had a worst-case scenario identified by the CFD analysis, and we focused on the results that we were getting from the 1D

analysis because it's easier to defend that type of calculation.

So, anyway, for the simple burning plume, we calculated maximum temperatures, and we also calculated temperature distributions that we could get on the containment pressure boundary. And those were entered into a structural evaluation of the containment survivability using an ANSYS model of the containment. This is the same ANSYS model that was used for Technical Report 9, buckling analysis for the containment shell. And from those analyses that we did on buckling analysis and an ASME Service Level C stress evaluation under the conditions of the hydrogen burn.

MEMBER RICCARDELLA: What's the maximum temperature that the containment was predicted to reach?

MR. SCOBEL: I'll get -- next slide. Okay. So for the containment shell, our maximum hot-spot temperature that we were calculating was, this is maximum surface temperature, peak inside surface temperature, 585 degrees Fahrenheit; for the hatch barrel and the insert plate, which are heavier, thicker components, 439 degrees; and for

the hatch cover, which is actually a thinner component, we were getting 741.

Now, we were calling the hot-spot allowables 650 degrees, which is based on the ASME code of maximum surface temperature for the steel, the containment steel. And for the hatch barrel, the temperature maximum was based on what would create the maximum temperature limit for the EPDM rubber that is used as the hatch seal. And on the hatch cover, we were seeing a peak of 741. We were calling the maximum allowable 800, but this was what triggered us to do the structural evaluation of the containment is that we were exceeding the 650-degree surface temperature.

So in order to do the structural evaluation, you know, the 1D analysis was calculating a hot-spot temperature. So we calculated temperatures for a hot spot where the plume would actually impact, would impinge on the containment shell, and then there were two zones. There was a zone below the hot spot which was the radiation zone because the plume was impinging, and then there was the zone that was where the plume was flowing along the containment shell, and that's Zone

1 area of convection and radiation together.

So we calculated temperatures onto this temperature distribution and performed a structural evaluation looking at two different temperature distributions, one of them assuming that the plume was hitting the equipment hatch at the top of the equipment hatch and one of them assuming that the plume was hitting at the exit of the, right at the roof because that's actually what the CFD analysis was predicting. At the notch, yes, at the notch. And the results of those structural analyses were that containment integrity was maintained, and we were showing reasonable assurance of survivability of the containment shell during this hydrogen break.

MEMBER REMPE: So I realize it's a very low frequency event, but you realize that there's differences in how MELCOR versus MAAP predicts hydrogen generation, and how much would your results change if you had more hydrogen being released --

MR. SCOBEL: Well, I was maximizing the hydrogen being generated by MAAP by increasing the surface multiplier for the zirconium. And also there are, when you look at this matrix of ADS cases, one other factor in this is that the PXS

compartment floods with IRWST water. When you have a double-ended DVI line break, when the IRWST is actuated, the PXS floods up. And it doesn't re-flood the core fast enough to prevent core damage, but it gives you a lot of water just at the right amount of time to create a lot of hydrogen.

MEMBER BLEY: Design feature.

MR. SCOBEL: It is, yes. And also the way MAAP models the DVI line, it's not plugging the DVI line with IRWST water. The DVI line is flooding in the model. What's flooding the PXS compartment is really a junction between the IRWST, it's a containment junction between the IRWST and the PXS compartment, and the DVI line is a junction between, basically, between the cold leg through the core makeup tank into the PXS compartment. So you get, like, two, you get a double blast of hydrogen from the DVI line.

So, yes, it's a feature. It's a conservative feature of the MAAP model that would be giving you more hydrogen than you would expect between the re-flooding. And so for different -- there's so many degrees of freedom in this problem, it's crazy. So you have the ADS, and the ADS, the

combination of ADS failures. If ADS 4 actuates, like I said, you're going to release the hydrogen from the hot leg, and it's never going to make it around to the DVI line or to the cold side where it can get released to the PXS compartment. But then the more ADS valves you have, the more re-flooding capability you can get, so you can get more hydrogen. So I believe that with the matrix of ADS valve combinations and all these different factors that we've created a conservative hydrogen release, even with MAAP.

MEMBER CORRADINI: Do you remember the source inventory that you were releasing, just I get a feeling for what --

MR. SCOBEL: I looked at it more as a hydrogen flow rate over time.

MEMBER CORRADINI: So what's the rate and what's the time?

MR. SCOBEL: The rates got up to, I think a couple of kilograms per second, and it lasted for approximately 500 seconds.

MEMBER CORRADINI: Okay. Thank you.

MEMBER RAY: Let's move on here.

MR. SHACK: Just another quick question.

I sometimes see an allowable for the EPDM of 390 degrees and 488. What's the difference between the two?

MR. SCOBEL: Well, the EPDM is located in the middle of the hatch barrel, and there's a temperature profile from the inside to the outside. So the 390 is actually the average temperature, and the 488 is the surface temperature that you get at that same time. It's the maximum surface temperature that you get over that that gives you 390 at the location of the hatch seals.

And I should also mention in the structural analysis, the structural analysis, because you have a temperature profile through the containment shell, uses the average temperature for the --

MEMBER RICCARDELLA: Well, when you talk about the structural analysis, are you mainly just addressing the top row on this table? I mean, do you care about the hatch cover --

MR. SCOBEL: Yes. Well, the hatch cover, the insert plate, all of that is in the model, so those --

MEMBER RICCARDELLA: I understand.

MR. SCOBEL: Yes. So those temperatures are applied accordingly.

MEMBER RICCARDELLA: But if the hatch cover were to fail, that wouldn't necessarily be a failure at the containment pressure boundary, would it?

MR. SCOBEL: It would. Yes, equipment hatch only has one, it's not covered on both sides. The personnel hatches have covers on both ends. Containment penetrations are sealed at both ends, but the hatch, the equipment hatch, that seal is, it's a double seal. You know, there's two EPDM rubber seals on the hatch barrel, but it's a single cover.

MR. SHACK: So when you say there's two seals and this 488 is the peak, does that mean the one seal is down below the 390, which I think of as the --

MR. SCOBEL: Yes, one is below, one would be a little above.

MR. SHACK: Okay. Just a peculiar way of quoting the allowables, but that's okay.

MR. SCOBEL: Right. I understand because when I was doing it it was like how do I do

this, you know. But this is the approach we took.

Any other questions? Thank you very much. MEMBER RAY: All right. So we had a change in the vent location and area and so on that had to be analyzed.

MR. TAYLOR: All right. Moving on, next in line is flux doubling algorithm compliance with IEEE-603. I'm Larry Taylor, Duke Energy. I'll be doing the presentation. In the audience, I have my Westinghouse answer man, Peter Morris, if there are questions we need his assistance with.

All right. So I know you're going to be disappointed, but there are no analyses calculations involved with this change. Basically, before I start too much in this, we talk about it later, but I think it helps to talk early on, if this change was not made, basically, the requirements and tech specs for when this algorithm is required to be operable, when this signal is required to be operable, were still in place and the operators would have administratively taken action to make sure they are complying with the tech specs.

What we did find, though, what Westinghouse did find was that there's a portion of

IEEE-603 associated with operating bypasses. It's in Section 6.6 of IEEE-603 1991, and it says whenever the applicable permissive conditions are not met, safety system should automatically prevent activation of an operating bypass or initiate the appropriate safety function.

For the flux doubling algorithm, there was not a permissive in place to prevent blocking the signal at any time. So what tech specs allows is when you're beginning the approach to criticality, this is not required to be operable or it would be actuating frequently as you're intentionally raising counts.

So what this change does is give us a new permissive, such that, besides just the operators complying with the administrative requirements, the system itself will establish a permissive for being able to bypass, perform an operating bypass, which in Westinghouse terminology we call block the signal.

So the new permissive is permissive 8. It is set at the minimum temperature for criticality for an AP1000, which is 551 degrees. So when I'm above 551 degrees, the operators will be able to

block the signal, perform their approach to criticality, and there would be no restrictions on being able to operate control rods or dilution of reactivity adjustment.

If I'm below permissive 8, the option was taken to perform an action to prevent a dilution, so the system will override shut two N series valves from the water system to the CVS system. When I say override, I mean, you know, as we said, administratively, operators would take action to close the valves to comply with tech specs and isolate the flow path. For some reason, if they have done that, the system will prevent those valves from re-opening. If they had not done that, it will close the valves and prevent them from re-opening.

So, again, to kind of reiterate, this change was made to comply with the IEEE standard. In reality, before the change was made, administrative controls were in place to take the appropriate action. The operators would take the appropriate action. Operators, we have procedures we follow very explicitly. For things like reactor startup, it's very much detailed and sequenced. The operators train frequently on the approach to

criticality. The operators have indication of permissive status on both the safety displays and the normal operator workstations.

So you might ask, I've told you why we would need to be able to block the signal to approach criticality. In addition, if we're in lower modes, lower temperatures, potentially we may be doing control rod testing or something that adds reactivity that we don't want a spurious actuation, so we can take action to isolate the dilution paths and go ahead and perform the needed testing and not get spurious actuations of the system.

MEMBER SKILLMAN: Is there ever a time when the operators would want demin water when you are below your minimum criticality temperature?

MR. TAYLOR: There is but, remember, normally -- I'll kind of answer your questions in a couple of ways and, hopefully, you can tell me whether it answers. So we isolate demin water, we do not isolate boric acid. So if there were the need to make up, we can still make up with boric acid without a blended flow.

There very well will be the need at some point to provide a blended flow, but the only time

these are shut is if we want to block the flux doubling signal because, normally, if I'm in the lower modes, I haven't blocked this actuation, and I can do the blended makeup. So this would be a very limited time in shutdown conditions where I'm doing some kind of testing such as control rod testing where I have to withdraw the control bank, add positive reactivity before I drop it. I change source range accounts and possibly reach the set point and actuate a boron dilution block. Did that seem to answer your question?

MEMBER SKILLMAN: Yes, thank you.

MEMBER STETKAR: But I got confused. If I'm below whatever the heck it is, 500 and some odd degrees, the flux doubling isolation is enabled, correct?

MR. TAYLOR: Correct.

MEMBER STETKAR: And if you see a doubling in flux, it automatically, then automatically isolates demin makeup, but only if you see a doubling in the --

MR. TAYLOR: Right. Those two out of four are coincidence, so, for an AP1000 --

MEMBER STETKAR: For the source range

stuff.

MR. TAYLOR: -- source range instruments, two out of four coincidence --

MEMBER STETKAR: Okay, I got it. Thanks. I got confused.

MR. TAYLOR: And we did greatly simplify the presentation. There is no analyses or calculation, but it's not an easy concept to address in some cases.

Any other questions?

MEMBER SKILLMAN: I do have one more. Maybe the answer is thoroughly obvious. I'm presuming that the operating personnel who have been part of the AP1000 design have not only bought into this change but endorsed it.

MR. TAYLOR: I would say yes. I mean, you're talking about Westinghouse-specific individuals or --

MEMBER SKILLMAN: It gets back to the question that Harold Ray asked. Here is an emergent conceptual design. I'll grant you, clairvoyance is not part of your skill set, so you don't know what you don't know. But you're embedding an operator prevent, and I will tell you every operator in this

room has, from one time to another, said that prevent gets in the way of what I got to do, I can't run this plant with that block or that prevent in place.

MR. TAYLOR: But what we're saying is they have to comply with tech specs. They would have done this anyway to comply with tech specs. In order to block this signal and make that inoperable, what allows me to do that in tech specs and not enter the LCO is to isolate the flow path.

MEMBER SKILLMAN: So this simply does it for them?

MR. TAYLOR: This, if they mess up and forget, get out of sequence in the procedure or something to that effect, this would do that. It also is required to be in place to comply with the IEEE standard.

MEMBER SKILLMAN: But I'm going to stick with my question. As part of this change, this modification, have those who are operators said, hey, we want this, this is what we want?

MR. TAYLOR: I can speak for myself. I'm one of the operators at Duke Energy with no training, but I'll let Pete's operational group

within Westinghouse and I'm sure he's consulted them.

MR. MORRIS: My name is Pete Morris. I'm at Westinghouse Electric Company. When this issue was identified, we spent a long time developing what turned out in the end to be a very simple-looking change, at least to somebody who deals with I&C. And the reason it took so long was that we put a lot of emphasis on trying to get input from a wide variety of people but first within Westinghouse, people that had operations experience, people who had been licensed operators, people who were developing the AP1000 plant procedures.

As part of our change control board process our utility customers, the utility representative in this room, had the opportunity to actually participate in the review of the design change proposal itself before it was approved. And in the development of materials that had been submitted to the NRC, there was significant interaction that we had with not only Duke Energy but also the other domestic applicants. And so there has been an enormous amount of input to the development of this from a variety of people with

direct operations experience.

MR. KITCHEN: Mr. Skillman, this is Bob Kitchen with Duke. I also want to add, as I mentioned earlier, we look at design change proposals. In this case, it was an item that's required, as Larry indicated, in ISG-11.

One thing I want to point out first, it's required not only by IEEE-603 but also by the regulations, Part 50, to do this. So we had to implement a permissive and a block.

But in terms of operational review, Larry is a very experienced SRO and, in fact, an instructor, as well. And we've had two other sitting reactor operators on our staff that review these kinds of changes, as well. We do provide operational looks at these kinds of changes.

MEMBER SKILLMAN: Okay. Thank you. Thanks.

MEMBER RAY: Anything else? All right. Now, the next transition will be after we return from the break that's scheduled here in five minutes.

MR. TAYLOR: We have one more --

MEMBER RAY: Oh, I'm sorry.

MR. TAYLOR: We need to do the open portion of --

MEMBER RAY: Oh, yes. I thought for a second that -- you're right. I beg your pardon. Withdraw all comments.

MR. TAYLOR: Some of this will be a repeat for those of you who were here for the closed session, some of it I skipped before, though. So we'll go through it again. So when we talk about background for the AP1000 main control room, the air temperature must remain at or below the defined limits during operation of the main control room emergency habitability system.

So as we mentioned before, this change came out based on two issues. One was related to what Andy has discussed before that we added equipment to the main control room without realizing the impact to the heat load. AP1000 is a little different. You don't have forced circulation, as such. So you have the passive heat removal. You really don't have margin to add much before you're approaching the issues.

The second one we discussed was this new scenario potentially that is more limiting than a

complete loss of all AC power. So a case where AC power remains but the non-safety control room ventilation system, VVS, for whatever reason, is lost or VES is actuated.

So the solution to resolve the issues was to create an automatic load shed that occurs in two stages. It does only select non-safety loads, no impact to the minimum inventory of controls or displays provided by the primary dedicated safety panel, and, as we discussed before, no impact to the non-safety plant controls. And then when we discussed the operator workstations, the local control station for the operators, those are also not impacted by the load shed. The load shed circuitry is safety related and in tech spec.

Okay. Some additional things accomplished by this change. There was action to limit the initial conditions for adjacent room temperatures in the updated main control room heat-up analysis, so we spoke to that a little bit during the closed session. And there's also additional tech spec surveillance requirements to limit the moisture content in the VES storage tank.

MEMBER STETKAR: Larry, let me just,

because this is open session, one of the things that I think we can discuss here that I just want to make sure we get on the open session record, I think Westinghouse told us that they also looked at other areas that are supplied by the VBS system to check to see whether the room heat-up analyses for the current compliment of equipment heat loads remain applicable for those areas also; is that correct?

MR. TAYLOR: Yes. Andy made that statement previously.

MEMBER STETKAR: And the only area that required any changes at all was the main control room itself?

MR. WILMOT: So we are analyzing that right now. We're in the process of doing those analysis updates for these other rooms.

MEMBER STETKAR: Oh, okay. So it's still in progress.

MR. WILMOT: Yes.

MEMBER STETKAR: Okay, thank you.

MEMBER BLEY: I have a kind of question before the applicant and vendor are finished here. We've heard a lot of -- what I'm going to ask doesn't have to do with the condensate return I

don't think but with all these other things. We've had a lot of changes going on in the design and, gee, doesn't inspection or something else help us with this stuff? I think Bob Kitchen and Andy Pfister gave us the answer this morning but not in enough detail for me to really understand it.

For years in the plants, when we make changes to the design, in many years past, 40 or 50 years ago, we put in things where people couldn't find where the systems went because we made helter-skelter changes and some clever engineer found a place to put a new valve in and a poor operator had to lie on his back to operate it. But now in the plants we have committees that include operations and engineering and maybe the risk people and some others to make sure that any changes are properly vetted and included.

I think what you gentlemen told us this morning said that part of this experience has led you to maybe something similar to that. You've changed how you look at these things. And if you can expand on that a little bit. I mean, many of these things we've heard about today involve changes that happen in the design that just weren't tracked

and, all of a sudden, when you go back and take a look, you say, oh, my gosh, we hadn't kept our analysis up to date.

So if you can tell us a little more what's formally been put in place to make sure this doesn't happen the next time around, I would appreciate it.

MR. KITCHEN: This is Bob Kitchen with Duke Energy. I'll try to address the way I understand the question, and I'm speaking for Duke and not the industry.

So we look at every design change that Westinghouse issues. We get an opportunity -- let me rephrase that. License design changes that affect the license. There are design changes that are below that threshold that we don't see. But we look at the design changes that affect the license.

We have an opportunity to look at those design change proposals in draft, and we provide comments. We look at it from an engineering standpoint, and we look at it from a licensing standpoint to make sure that we're getting the right perspectives for input.

In any case, Westinghouse, it's their

design change. They prepare the design change and address comments, as appropriate.

The other part of the look that we do is what we talked about and why we're here. We look at using the ISG-11 threshold for what changes the staff should be aware of before they issue a safety evaluation. And there's approximately, since the VC Summer license, about 300 design changes that affect the license. We're talking about five. So it gives you a feel for how many cross this threshold.

And we keep the backlog very low. We run about a five-percent backlog as of today.

So we're looking at the change in terms of capturing, you know, for the most part, for us, are future change. We just looked at them and said we have to do these five now, the other are future changes. So when we move forward, we'll address those in our construction and implementation. In the same way Vogtle and VC Summer are dealing with the construction, hopefully we'll have the opportunity to be further ahead, but we will have implemented those changes in our license to reflect so we don't affect construction.

So that's what we're doing. We're

capturing all of these in backlog. Now, separately, we have a routine review that we do of design change proposals to basically say is this a change that we think we would prefer to do differently? Not that it's wrong but, for some reason, we would like to do that differently.

I'll tell you, at one point, we had a list of DCPs that was fairly long, and Erik Wagner and his team have gone and worked through those. We're down to, you know, probably a couple dozen DCPs that we think maybe we might want to do differently. That's something we'll cross and brief later. So we're tracking those in backlog as items that we want to talk to Westinghouse about, and we want to minimize that. That's why we've gone through these. We want to be standard, and we're not going to implement change just to be different.

So we've captured these changes in backlog in terms of implementation post license and in those that we think we need to address prior to the license issuance we're talking about today. But along with that change goes, and we have not done, in many cases we haven't gone at this point and reviewed all of the calculations and reports that

would support a design change that we're going to do later. That would be a subsequent review. So I'm not sure if that --

MEMBER BLEY: It helps, it helps, yes. Thank you. And I don't know if Westinghouse wants to make a comment.

MR. CUMMINS: So it's Ed Cummins, and I'll make a couple of comments. We have a configuration control board that's got ten people, and they meet once a week. And we have about one change a week. Sometimes we have, in the past, more. So there's a lot of them. The things that come before that board are Class 1 changes which affect the license.

Most of them don't have much effect on the license. It just can be "and" instead of "or." But sometimes they have a lot of effect, and we're talking about them here.

So in all of those, we have a review every Thursday morning, and all of the customers are invited. Most often, they're all there, and they have opportunities to comment as we approve the process. And so it's actually a fairly efficient process because they've all been sent this before.

They have written comments before that are supposed to be resolved so that we don't have to do that in the meeting. And so in a half-hour, we approve the -- and everybody knows about it, too. It's a great communication because all the customers and responsible engineers have already reviewed it and said, well, I agree with this.

MEMBER BLEY: Thanks.

MR. TAYLOR: Okay. Last item on this slide, one of the other things the change did, we included some human factors considerations, so analysis supports, the new analysis supports unlimited operator stay time and wet bulb globe temperature index of 90 degrees Fahrenheit. This acceptance criteria is from NUREG-0700, and, again, in the new analysis, this same limit is met for post-72-hour ancillary fan operation, in addition to VES operations.

So we discussed this slide in the closed session. Just to go back over it in open, the summary of the analysis required to support the change, there was an updated GOTHIC model. The main control room was refined to show greater resolution. As John mentioned before, there's additional points

added for better resolution. The heat loads are distributed to reflect as-designed layout. Surveillance requirements verified assumptions are bounded, and the analysis was extended to post-72-hour model based on operation and VES ancillary fans.

All right. Now we are to the end of our slides.

MEMBER RAY: I apologize for being premature. But, anyway, we're still very much on schedule. I'll ask my colleagues once again, since this is the last Westinghouse and Duke will still be here, but we'll be hearing from the staff after our break to complete the agenda. So as Dennis just did, if there's anything else anybody wants to direct to folks at the table in front of us, please do it now, but we can raise questions as well, I'm sure.

With that, we'll take our final break of the day, and I'll ask that we resume at five minutes after three, giving the staff plenty of time to do their agenda items and perhaps even get done early. So thank you. We'll recess for 15 minutes.

(Whereupon, the above-referred to matter

went off the record at 2:52 p.m. and went back on the record at 3:07 p.m.)

CHAIRMAN RAY: We'll come back into order, please. And we will commence the last of the open session, Item 12. Right now we are running a little over 20 minutes ahead of schedule. Don will do his best to keep it that way, but nevertheless, we can take all the time we need. So, Don, go ahead.

MR. HABIB: Okay, we will be covering -- the staff will be covering the same departures that the applicant did in a slightly different order. But basically, dose, then heat-up, then the hydrogen vent, and then the flux doubling.

So, to start off with the dose presentation, the review team included the two presenters beside me, Michelle Hart and Ron LaVera from Radiation Protection, Eduardo Sastre from Materials and Chemical, Nan Chien from Containment and Ventilation, and myself as project management. And with that, I will turn it over to Michelle.

MS. HART: Okay, for the main control room dose departure, in July of 2014, Westinghouse came in and gave a presentation and said that there

were some discrepancies or deficiencies in the AP1000 DCD main control room dose analyses. And as they had presented earlier, it did not include the filter shine in the control room from the VES filter. The dose contribution from other sources of direct radiation required some updating. The system actuations at points needed revision to ensure GDC-19 was met for all DBAs and as they presented, the main steam line break most limiting scenario for the control room dose wasn't modeled in the DCD.

The revised dose analyses that they provided as part of their dose departure affect all the design basis accidents. They re-analyzed all of them. The analyses that they presented are generic, much like the DCD analyses are generic and they used the design site parameter, these χ/Qs, the atmospheric dispersion factors that are the same as in the DCD and they were shown to be applicable to Levy because the site characteristics, χ/Qs for Levy are less than design site parameter χ/Qs. So, they could incorporate those new analyses for the Levy site.

The revised analyses added the direct radiation dose contribution from the main control

room filter and had additional analysis changes made to increase the analysis margin and update or incorporate updated detailed design information.

When they did these revisions, there was the potential that they may exceed the GDC 19 dose criterion of 5 rem TEDE. So, they added shielding to the VES filter and they reduced the tech spec allowable secondary coolant iodine activity concentration, and they revised the radiation monitor setpoint values.

So as far as the licensing impact, the actual changes to the to the SR that they showed to take a departure from the DCD just to revise the DBA dose analyses so there were several changes they had to make to the information that was recorded in the DCD, the design change to add the filter shielding and related to ITAAC, the tech spec changes for the secondary coolant iodine activity concentration and change the VES actuation signal name from high-high to High-2. And there were multiple changes in all of those chapters reflected in the DCD, including Tier 1 changes and tech spec changes.

So, as far as the direct radiation dose or the shine dose, the areas examined by the staff

were the dose from the VES filter to the control room operators and the credit for the shielding provided for the VES filter that they had added and the analysis methods used by the applicant. They did revise those analysis methods over what was used in the design certification.

To review these methods, the staff performed some scoping calculations. So, the applicant had used in Westinghouse for the applicant had used MCNP, which is a Monte Carlos code. We also did some scoping analyses, some limited analyses to look at what they had done. We also used MicroShield to look at kind of a bounding kind of information for that, some Excel spreadsheets to look at the radiation handling. And I used Origen-ARP to look at the filter loading and convert that into a gamma source for the MCNP calculations.

We also audited the applicant's main control room envelope design packages as far as the physical changes in the analysis packages for that. We looked at -- we were able to look at in paper form the MCNP shielding calculations that they had performed, their input and output files, for both the VES filter, the VBS filter, and the plant and

main control room shield walls for the direct penetration through the walls and through penetrations.

And so the results of that, the scoping analyses and the audit of them and the review of the information that they provided in their departure was that the amount of margin between the calculated main control room dose ensures compliance with GDC 19 for the use of the safety related VES system.

As far as changes to the design basis dose analyses that were not related to the direct dose, there were certain changes that only affected the main control room dose and those where they discussed about updated design, detailed information, increase in the assumed filter efficiency for organic iodine, they did not change the filter. They just made changes in the assumption that were in accordance with our regulatory guidance.

They changed the size of the control room and the ventilation system flow rates for the main control room ventilation systems. And they changed the VES initiation time based on those revised radiation monitor setpoints. So, those

would only affect the dose in the control room that would be calculated.

They did make additional changes that would affect both the main control room dose and the offsite dose results and they are listed here. The main ones were the tech spec change to change that secondary coolant iodine concentration, the revised main steam line break release rates, the use of the updated approved method to estimate fuel damage for rod ejection accident. And an increased value for containment elemental iodine deposition removal coefficient and that was based on the physical characteristics of the AP1000 plant, the updated design information and the revised modeling of the iodine re-evolution from the IRWST.

As compared to the design certification, this used updated design and detailed information as well. It was the same method, just newer information for the AP1000 design itself.

And there were other changes like that that used the updated detailed design information.

So for that, for these other changes, we audited their calculations in paper form. The design change packages, we also looked at those to

make sure that those were reflected in the analysis that they did. And we also did a comparison of the proposed revised methods to the NRC guidance to make sure that those fit.

We found that the proposed changes are acceptable because they either used methods that were previously found acceptable in the design certification or in conformance with NRC guidance, or they are just using updated detailed design information and then they are not really changes to methods or major changes to the plant, or they reflect proposed site-specific changes to the design, such as the shielding -- I mean not the -- well, the shielding is not site-specific.

The revised design basis dose analyses show that the estimated offsite and main control room doses meet the applicable dose criteria. So, they were able to show that they still remain within the regulations.

So, therefore, the staff has a reasonable assurance that the proposed main control room dose analysis departure and exemptions meet the following requirements, the offsite dose requirements of the EAB and LPZ for all design basis

accidents, including the acceptance criteria in the SRP 15.0.3 for all of the DBAs and that the control room habitability dose criterion, GDC 19 is meant for operation of the VES under High-2 radiological conditions for all DBAs.

Do you have any questions?

CHAIRMAN RAY: Any questions on this one item? Thank you.

MS. HART: Thank you.

MR. HABIB: So, we will continue on with the main control room habitability or heatup presentation. And the review team includes these two presenters, Boyce Travis from Containment Ventilation, Paul Pieringer from Human Factors Engineering, the other reviewers, James Strnisha, Jack Zhao, Hien Le, Malcolm Patterson, Nan Chien, Kevin Quinlan, and myself, Don Habib, Project Management.

So, with that, I will turn it over to the presenter, Boyce Travis.

MR. TRAVIS: Sure. So, I will be discussing some of the technical aspects associated with the change and Paul will discuss the human factors impacts near the end of the presentation.

So for the load shed, there are two periods of interest with respect to main control room and surrounding area temperature and humidity, the first 72 hours where VES is in operation and then the period after that, between three and seven days when ancillary fans operate.

The new heat load, which Westinghouse discussed earlier, as a result of the load shed and the reevaluation of the heat loads in the control room is added to the GOTHIC and the analysis changes are incorporated with that to change the temperature profile from what was in the Revision 19 of the DCD to what is going to be presented or was presented by the applicant and it will show up on our slides here in a bit.

The applicant also changed the acceptance criteria for human performance from an effective temperature in accordance with the MIL Standard to a wet bulb globe temperature of less than 90 degrees in accordance with NUREG 700. For those of you unfamiliar, as I was at the start of the review, a wet bulb globe temperature is a combination of the wet bulb temperature and the dry bulb temperature for a site. It is 30 percent of

the dry bulb temperature and 70 percent of the natural wet bulb temperature.

MEMBER CORRADINI: And for those that can't remember why, what does that imply?

MR. TRAVIS: So, it is --

MEMBER CORRADINI: I know what the two are. What does the combination imply?

MR. TRAVIS: So, it is meant to be representative of an effective, kind of a temperature associated with human exertion, I guess. Can you elaborate on that a little?

MR. PIERINGER: Yes, the experimental data they take temperature and humidity and they look at the combined effect on human performance and it is easiest to express as the wet bulb globe temperature but I think of it as just the combined effects of temperature and humidity on personnel performance.

MEMBER CORRADINI: Okay.

MR. PIERINGER: There are some correlations they make with dress and metabolism that go along with that.

MEMBER CORRADINI: Thank you.

MR. TRAVIS: So, the human performance

criteria is a wet bulb globe temperature of less than 90.

And then the equipment qualification is a curve that is represented in the first three days by a temperature of less than 95 degrees and 60 percent relative humidity, which is about a wet bulb globe temperature of 82. And after three days, the curve is represented by a dry bulb temperature of less than 110 and a 35 percent relative humidity which is a wet bulb globe temperature of about 84 degrees.

So, for the first 72 hours, our staff --

MEMBER CORRADINI: The last two, just to make sure I remember, the last two are site-dependent or this is a bounding one within the certification.

MR. TRAVIS: That is a bounding one that is going in the certification.

So, with respect to the first 72 hours, the staff reviewed the GOTHIC analysis and found it conservatively captured the main control room temperature with the new heat load and the addition of going from a single node to a couple hundred nodes in the control room. The profile will be in

a couple of slides from now.

The applicant, for initial conditions, the applicant assumed an ambient dry bulb temperature of 115, which has very little impact on the analysis, except to determine some wall temperatures.

And humidity was calculated separately by the applicant. Because you start with an initial value in the control room and you are pressurizing -- not pressurizing -- but you are adding the air to the control room from the VES bottles, eventually the control rooms get to the point where the input air from the VES bottles is going to equal the air that is expelled as a result of you pressurizing the control room to some nominal value, very low.

The applicant used initial conditions of 75 degrees, which is the tech spec maximum and 60 percent relatively humidity, which is the alarm state for the main control room. And they determined humidity in the control room and found -- and then used a bounding input above that.

Staff agrees that 75 and 60 are the alarm conditions for the control room but tech specs limit the control room to 75 degrees. There

is no tech spec limit on the humidity in the control room.

MEMBER CORRADINI: Can I ask kind of a side question?

MR. TRAVIS: Sure.

MEMBER CORRADINI: I should have asked the licensee this or the Westinghouse this. What is the pressure in the VES bottle?

MR. TRAVIS: So, it is roughly 3400 psi.

MEMBER CORRADINI: So, do you get any Joule cooling? Is that included in the calculations?

MR. TRAVIS: I will get to that on another slide. The Joule-Thomson effect, they take credit for it, although --

MEMBER CORRADINI: Okay, they do take credit for it.

MR. TRAVIS: Yes, they take credit for it, although it has an impact on the regulator that I will discuss a little later.

MEMBER CORRADINI: Ice formation?

MR. TRAVIS: Yes. It's okay.

So, the staff, in our confirmatory analysis, we looked at a control room or initial

conditions as 75 degree Fahrenheit and 100 percent relative humidity because ultimately, that is the value that tech specs limit them to. We found a maximum wet bulb temperature in the control room of about 79 degrees and in applicant's analysis, they assume a constant wet bulb temperature of 80.1 degrees. So, that is why we accepted their conditions.

And the main control room is substantially lower than a wet bulb globe temperature of 90 in the first 72 hours. Ultimately, the equipment qualification was the limiting parameter for that period.

So after 72 hours, ancillary fans are placed into service to ventilate roughly 1500 cfm of air through the control room. And so the outside, whatever the ambient conditions are, the primary driver, as you saw in the applicant's slides, it results in the control room heating up because you have to assume a fairly hot outside temperature.

And in fact, the applicant assumed a diurnal temperature curve with 101 degree peak, which is the one percent site exceedance temperature and a 15 degree delta between the peak and the night

temperature. And they assumed a constant level of temperature of 82.4 degrees.

So, in the slides that will follow this, the staff compared this value to NWS data near the Levy site and we have also looked at the data for the other AP1000 sites and other hot locations in the U.S. and found that this was a bounding temperature curve that the applicant input.

And so staff concluded that there was reasonable assurance the analysis showed that the control room remained below the human performance criteria of 90 degrees wet bulb globe temperature and also below the equipment qualification, even under the worst case outdoor conditions. And expected outdoor conditions would be substantially lower than what would be input by the applicant.

And so if you move on to the next slide. So, this curve shows the applicant's input conditions and the control room conditions that are calculated. The light blue curve that starts out at 115 at the very top and then proceeds into that diurnal is the assumed outdoor dry bulb temperature. And the orange curve is the assumed wet bulb temperature and after three days, it is effectively

also used as the wet bulb temperature for the outside.

The dark blue curve is the calculated temperature in the main control room.

So, on the next slide --

CHAIRMAN RAY: Just a second. Don, have we gotten any feedback that maybe one of the other AP1000 users might take a different approach here in any way on this topic?

MR. HABIB: Well, for the applicants, Lee and Turkey Point, they do plan on following this. For the licensees, they have expressed that they are going to do something but whether it is exactly this or something else, they have to go figure that out yet. They haven't shared that with us. So, it is possible that they will take a different approach.

CHAIRMAN RAY: And if they do take a different approach, I take it that that would have an impact on the review the staff would do -- could have an impact on the review the staff would do. In other words, would you have to repeat what you did here for a different approach being taken?

MR. HABIB: That is correct. I mean if

they do the same thing, then we verify it and it is done. If they do something different, then that is a new review that we would have to do.

CHAIRMAN RAY: Thank you.

MR. TRAVIS: So, on the next slide, there is a more detailed comparison of the temperatures that were assumed outside and the temperature -- what is being presented here is National Weather Service data from Tampa, Florida, which is a hot site very near where the Levy Nuclear Plant would be located. And the data is the worst four consecutive days with respect to wet bulb globe temperature.

We also have some data that I will show on the next slide that includes the worst single hour with respect to wet bulb globe temperature near the Levy site.

The data has been, it cuts off a little before Day 7 because I had to synchronize the data up to trying with the peaks and I didn't want to replicate the data that we had before. Ultimately, though, the limiting condition which is really humidity after seven days is still bounding. And they maintain the dry bulb -- this input maintains

the dry bulb temperature under what would be required by the analysis.

So, on the next slide, this is ultimately the payoff with respect to the comparison and the acceptance criteria. So, the acceptance criteria of human performance is 90 degrees wet bulb globe temperature and it is a brown line, the flat line at 90 degrees. The calculated wet bulb globe temperature by the applicant is a gray line. It starts at about 85 and proceeds up to about 88 degrees at the end of the transient. The assumed outdoor wet bulb globe temperature is kind of a compressed cosine curve there in the green. And then the data that the staff looked at for the Tampa site includes the orange curve, which, as I said, was the worst four -- so the average, rolling average over four days, the worst wet bulb globe temperature that was found at Tampa.

And then the red curve is the worst single day, so the worst single hour, really, for wet bulb globe temperature repeated four times. That is why it looks the same four times in a row.

So as you can see, even the peak wet bulb globe temperature that was ever recorded at

Tampa is still substantially less than the peak that is being assumed to be in the control room by the applicant.

And we have looked at this data for other -- I have it in a backup slide if the ACRS wants to see it but we have looked at this data for other AP1000 sites and other hot sites in the United States and we see a very similar trend. But the green curve bounds all of the sites that were chosen.

So, moving on to the next slide, I will speak a little about what Dr. Corradini was speaking to earlier. The certified design lacked humidity control of the air in the VES bottles. And so if the moisture content in those bottles was high enough, there was the potential for freezing at the VES regulator, due to the Joule-Thomson effect. They dropped from, I think, at the regulator from 3400 to about 100 psi. And so it is a pretty substantial temperature decrease. You could see like minus 20, roughly, in that area.

And so because there was no moisture control, the applicants expressed to us that this was intended to be filled with instrument air, which

is a dry air source.

The associated increase in humidity, if the air was not dry, could have impacted the analysis as additional humidity input and could have frozen the regulator, which would have resulted in VES either expending itself too early or not working at all.

And so the staff asked an RAI and the applicant proposed changes to the FSAR to state that there would be moisture control on the VES bottles, it would be supplied at an ANSI Quality Level E with a pressure dew point temperature not to exceed 40 Fahrenheit at 3400 psi, which the staff's review indicates that at that temperature, the regulator would be in no danger of freezing.

So, I will turn it over to Paul for human performance impacts.

MR. PIERINGER: To start with, we took the load list and verified that in fact the loads didn't affect operating performance. The only two areas that stood out to us were the loss of lighting and the wide panel information system. We did verify that there are battery-backed lighting. The application did say that it was sufficient lighting

and that was consistent with what we observed in the integrated system validation when a station blackout was run.

The wide panel information system was credited in the AP1000 design certification safety evaluation as part of the state-of-the-art control room supporting teamwork, situational awareness, and command and control. So, it was of much interest to us on when this kind of loss would occur. And on the next slide, I have outlined kind of our -- I have outlined our thought process as we evaluated this.

It took us a little bit of time to understand that this non-safety-related system had all the functionality of a safety-related system, except for some of the design specifics, seismic. But when we did realize that it was two independent trains, both with filtering capability sufficient to keep control room doses less than GDC 19 criteria, it created additional questions about when would this condition occur. What was the probability that we would be in this kind of an operational situation?

So, in the safety evaluation, you will

see a table where we basically identified all the possible combinations we could think of to provide a structure with which to evaluate the frequency and the conditions under which this loss would occur.

From there, our big interest was how often it would occur in an operating condition where it didn't cause a trip or where the event didn't cause a trip. The thought there being that you would be operating at power without the wide panel information system.

And then the closing thought was if you did need to operate that way, what indications remain available. That is a pretty easy question. You saw the pictures earlier but I will speak a little bit to that later.

The first question, what events must occur to result in the VES actuation, after compiling everything we found basically three events or three conditions that occurred at power and allowed the plant to stay at power. And they were spurious VES actuation, VBS failures requiring manual VES initiation, and then we had a rather outlandish scenario where one of the other plants on-site had a meltdown and a release and that source

term somehow got to the operating unit and created a high-tooth signal. Very improbable but we were just looking for combinations of things that could cause this scenario.

The ones that we spent the most time on were the spurious VES actuation and the VBS failures. When we looked at these two scenarios, the immediate question was how long would you be at power. And through information provided by the applicant, we understand that there is 26 hours is the estimated time at power. A tech spec would cause you to shut down after that. But you would have to be in hot shutdown within 26 hours because of tech specs on the capacity of the VES tanks.

Our thought here was that that was not an unsupportable amount of time to be at power because, going to the last bullet, you do have alternate indications at the shift manager's desk, the senior reactor operator console, and the reactor operator consoles.

It was a bit confusing to us because of the material presented. It was unclear whether the operator -- it was clear in the pictures that the reactor operator consoles remained energized but it

was not clear in the verbiage that they were. There was an inconsistency there. That was addressed via a request for additional information and the material was clarified. And that is why I have excluding the business LAN because that is information that is lost when the load shed occurs.

MR. TRAVIS: So, in conclusion, the staff found that the main control room remained within the temperature and humidity limits for both human performance and equipment qualification.

In the first 72 hours, there is substantial margin with respect to human performance. And post-72 hours, even with the ancillary fans blowing outside air in, there is still margin for both equipment qualification and human performance.

Associated with that, the staff found the change of acceptance criteria for control room habitability from and effective temperature of 85 in accordance with the MIL Standard to a wet bulb globe temperature of less than 90, which is acceptable, as per the guidance in NUREG-0700. The staff found that change acceptable. And it maintains an unlimited stay time in the control room for at least

seven days.

And the staff found that, ultimately as Paul said, given the low probability of events resulting in a wall panel information system load shed and the availability of the alternate indications, the load shed doesn't undermine implementation and provided the acceptability of the inventory available to the operator.

MEMBER STETKAR: I would like to get to -- Paul, you went through this really quick. And this low probability of this thing happening you seemed to -- if I go back to your slide 20 whatever the heck it is because our numbered slides are different from yours. Multiple independent failures and/or beyond design basis events. Well, can you talk about them being multiple independent?

The VBS is not safety-related, as you notice. It is not in the tech specs. It is not in their reliability assurance program, as far as I can find it. So, it is just a sort of a system in the plant.

It has got chillers in it. It has got a chilled water system to support it. It has got HVAC units. Those things aren't particularly reliable

pieces of equipment. They can be out of service for maintenance. I read recently of a plant that actually had to shut down because they had two trains of ventilation and one of their chillers had been out of service for a long time and the other one, they opened and they couldn't replace it. They couldn't fix it.

So, I am guessing that maybe I might lose VBS to the control room, maybe once every ten years or so. That is not, to me, a very rare event. So, what is a rare event to you guys?

These are comparable events. They actually happen. And ventilation systems are not the most reliable, even safety-related ventilation systems aren't the most reliable systems in the whole world. The fortunate thing, safety-related, people have to repair them quickly.

MR. PIERINGER: I don't have a number.

MEMBER STETKAR: So, well, but if I ask you if your conclusion was based on the fact that this would be the need to de-energize the things that I live with every day and I am really familiar working with, if I needed to do that once every ten years or so, is that still reasonable for you from a

human factors perspective?

MR. PIERINGER: What I found reasonable was the combination of if it fails, you have a tech spec that requires you to shut down in 26 hours.

MEMBER STETKAR: Yes.

MR. PIERINGER: So, if you are in maintenance, that is one failure and the other train fails, now you are in an action statement. And so the exposure to a subsequent event, which is what I was worried about is that 26-hour period, where the operator might have to take additional actions that were outside of just a shutdown.

And if that happened, if he had to manage some other situation, he still has the full indication suite on the local control panels -- the local operating panels.

MEMBER STETKAR: Sure but it is something that he never uses.

MR. PIERINGER: The local operating panels?

MEMBER STETKAR: For situation awareness, he doesn't use it.

MR. PIERINGER: Well, he is using the local control panels as a standard operating

platform. That is where all of the controls, alarms, and indications will show up on one of those four panels. The wide panel information system is just providing the top level of information, direct safety function-related information. It has got some mimics that provide plant status but it is a high-level and the operator can replicate that on the control panels at the local control station.

MEMBER STETKAR: I must be remembering -- maybe I am remembering a different control. It has been a while since I have looked at the AP1000 control room design and I may be remembering a different design, where the wide display panels or whatever you call them were really what people used. I mean you know they had local ability. I must be mis-remembering the AP1000.

MR. PFISTER: Yes, the wall panel -- this is Andy Pfister from Westinghouse. The wall panel information system is just an information system. The controls are done at the local control panels.

MEMBER STETKAR: Okay, I'm sorry. I must be --

MR. PFISTER: And as I said, he can

replicate everything at the --

MEMBER STETKAR: The one that I had visualized was much different than that.

MR. PFISTER: There is lots of information there that is useful to an operator but the controls are manipulated at the RO console.

MEMBER STETKAR: Okay, thank you. I'm sorry.

MR. PIERINGER: And John what we are really trying to do in the wide panel information system is credit it as part of this state-of-the-art. Because we lost all the visibility of the old panels that we used to have, this was a good way to provide that information to all the operators at all the same time.

MEMBER STETKAR: The design I was remembering, though, is the operators really used that big panel display for their primary means of feedback. But that is irrelevant to this design.

MR. HABIB: Any other questions?

MR. CUMMINS: So, this is Ed Cummins. So, the big displays, those displays can be seen on the computer screens but they can't be seen continuously.

CHAIRMAN RAY: Anything else on this topic? If not, we will move on.

MS. GRADY: Good afternoon. I am Anne-Marie Grady from the Containment Systems Branch and the Severe Accident and PRA Branch.

CHAIRMAN RAY: Good afternoon.

MS. GRADY: Good afternoon.

I'm here to discuss with you -- that's the next slide. Sorry. I just want to make sure we are not missing one. Okay.

MEMBER BLEY: Anne, could you watch the microphone with your papers.

MS. GRADY: The light is green. What does that mean?

MEMBER BLEY: It's on.

MEMBER STETKAR: It's on but it is really sensitive. If you hit it with the paper, it is noisy.

MS. GRADY: Is that what you meant?

MEMBER BLEY: That's what I meant.

MS. GRADY: Thank you. Okay.

The purpose of the review was to establish the consistency between the AP1000 certified design and the Levy plant. The licensing

impact includes an exemption request and two departure requests. The exemption requests is the Tier 1 information, the ITAAC, and the departure requests are in Chapter 19.1.7 or 4.7 and Chapter 6.2.4.

CHAIRMAN RAY: So, there are two departures with this exemption also?

MS. GRADY: Well, perhaps that is my wording. In my --

CHAIRMAN RAY: I think it is because we have been counting these things all day long and --

MS. GRADY: But the topics, this is all one topic, a single topic. It just affects two different parts of the application. And when it is Tier 2, I call it a departure. When it is Tier 1, I call it an exemption. That is me.

CHAIRMAN RAY: We are all learning here in this experience. We have got to get a lexicon that we all -- because the main thing is it just diverts people and they think they have missed something. Because we think we have got five exemptions and six departures total, which didn't include two departures with this exemption.

That's fine. Go ahead.

MR. HABIB: Just for clarity, you know there were six numbered departures. This one was a little different just in terms of the Tier 2 information. There were really only two changes, whereas if you look at main control room heatup or dose or condensate return, there were literally dozens of changes.

But this was all categorized under 6.2-1.

CHAIRMAN RAY: I'm just pointing out -- I don't expect the committee will want to tell the Commission this but I am saying to the staff but we have got get a vocabulary that everybody is familiar with so when you count up things to decide did I see everything I was supposed to see, you are on the same page.

But all right, go ahead.

MS. GRADY: We're talking about a single design change. And the design change came about because Westinghouse was evaluating whether or not or how they were going to meet the ITAAC in the area of the PXSA room in the containment and the core makeup tank area. And they found that because of changes that had occurred over time, that they now

had a physical configuration which was different, which made the earlier analysis, the diffusion flame analysis, for that area in need of an update. Hence, we are now, we have been reviewing their analysis.

Okay, in addition to the Tier 1 ITAAC change, there is also a change in Chapter 6, Preoperational Testing and Inspection of the Hydrogen Ignition System and also in Chapter 19, 19.41.7, the Diffusion Flame Analysis. So, that is where you find all of the changes -- all of the differences related to this single change.

Okay, the goal here to be met by this analysis, by the original analysis which was met and by the current analysis is to comply with the policy that is stated in SECY-93-087, which really says that we have to maintain a leak-tight containment barrier following a beyond design basis accident for at least 24 hours and after that, to have a controllable leak.

So, as long as this change doesn't turn out to be an accident that impacts the containment integrity, we have met the regulatory basis for the change.

The goal here was to keep the hydrogen -- the postulated hydrogen diffusion flame sources way from the containment pressure boundary to prevent conditions leading to potential failure of the containment shell, hatches, and penetrations.

The purpose of the ITAAC is to confirm those distances.

The applicant review realized that a burning hydrogen plume from the passive core cooling system, PXS-A compartment, to the core makeup tank room could potentially challenge containment allowable limits.

Okay, so the technical evaluation involved three analysis. The hydrogen venting scenario, as Westinghouse has already mentioned, was for a beyond design basis event, involving hydrogen generation due to fuel clad oxidation.

The scenario pertains to a single initiating event, which is a DVI line break which spills in to the PXS-A compartment below the core makeup tank. The break has to be large enough -- I'm just trying to show you how unusual this event is, however, it was in the existing certified design. It is in the FSAR, Rev. 19. And this is

the scenario that is being analyzed. No change in the scenario. The break has to be large enough to defeat injection through the DVI line and the PXS-B line must also fail to inject.

Then there have to be multiple failures of the ADS-4 function in order for the hydrogen that is generated to be released into the PXS-A compartment.

The cut set frequency for this scenario, as has already been mentioned, is 6.4E-09 per reactor year.

The applicant performed a CFD sensitivity analysis to locate hot spots and any flow split variation in the PXS-A room vents. As you have seen from the figure, there are two that are referred to as vents, one relatively large one, one much smaller one, and then there is this notch along the containment shell. And they are all, at one time or another, referred to as vents.

And by the way, I should say that the review that staff did, that's me, and then also Parvin, who did the structural analysis, was in the form of an audit. Westinghouse produced new calculations. We audited their calculations in

their facility.

Okay, back to their analysis. They performed a 1D heat transfer analysis to calculate the temperature on the containment pressure boundary. They considered radiation and convection as the heat transfer modes. The maximum temperatures on the containment shell, the equipment hatch, which projects about five feet into the containment itself, closer to the flame than the shell is, and the hatch barrel, which is in-between, were calculated.

The temperatures were averaged through the distance of the material that we are talking about because that is the appropriate input for the structural analysis plus a structural program that they used in the analysis.

And these are the results of the information that was used as the input into the structural analysis. Westinghouse showed you an earlier slide in their presentation, where they calculated the maximum surface temperatures. But then as I just mentioned, and as they I believe also mentioned, they averaged them through the material. And this is the input into the structural analysis.

And that ended my review, which was the hydrogen diffusion flame analysis and then structural picked up the structural analysis. Pravin?

MR. PATEL: Thank you. My name is Pravin Patel, NRO.

The issue here is the hydrogen diffusion flame migrating from PSX-A compartment may challenge the containment integrity due to temperature increase, as we talked about this afternoon.

The resolution to that that staff focused on is survivability of the containment vessel including the equipment hatch, in order to conclude the safety findings.

The staff also audited, as mentioned, that the structural analysis calculation typically is attached to the other analysis appendix. And we looked at it at the Westinghouse office here.

The staff put emphasis on mainly temperature distribution on containment vessel and equipment hatch, which is a hot spot. We talk about it because that is what the issue is we consider. The affect is the containment pressure boundary because of the burning plume is projecting towards

the equipment hatch.

And in your handout, there is a correction to the slide. Instead of maximum temperature it is the peak average wall temperature, which is correct on the display right now. So, if you can hold that, please. Thank you.

The temperature limit of the 390 degree Fahrenheit, as we discussed, that is the average temperature on the equipment hatch seal and it is based on the EPDM rubber manufacturer allowable, as mentioned from the Westinghouse presentation that there are two seals rubber that is behind the equipment hatch and equipment hatch is a concrete surface and then there is a lip that is attached to the main containment vessel to core as a cover.

So, what the containment vessel and the hatch stresses are within the ASME allowable for the ASME NE-3000 section Service Level C, which is required by the AP1000 DCD, as well as the Reg Guide 1.216.

The metal resultant stress of what was applicant calculated was 15.25 ksi with the ANSYS analysis based on average temperature input to the elements, solid element of the ANSYS versus ASME

allowable of 63.6 ksi at the 800 degree temperature, which is kind of a good value because if it was 700, it might be a little less.

So, basically, they are well within the allowable and this is very low pressure event and is very rare event also.

And metal creep is not a consideration here because it is very small time limit for the event, which is around less than ten units.

So, staff concluded that applicant analysis meets the ASME requirements and containment integrity is not challenged.

And any questions for the structure part, please?

MEMBER RICCARDELLA: The 15.25, that is a membrane stress, general membrane?

MR. PATEL: That is the maximum resultant stress. That calculates with the ANSYS that you know -- yes, membrane. Right, correct.

MEMBER RICCARDELLA: It is not a peak local stress. You didn't look at -- it is a membrane, I would think.

MR. PATEL: Membrane, yes.

MEMBER RICCARDELLA: But that is what

you compared.

MR. PATEL: Yes.

MEMBER RICCARDELLA: And I guess it is testing my memory. I didn't know the SME -- this is carbon steel. I didn't know the code limit went up to 800 F for carbon steel.

MR. PATEL: Carbon steel, this is there was two allowables.

MEMBER RICCARDELLA: Division 2?

MR. PATEL: Yes.

MEMBER RICCARDELLA: Okay.

MR. SHACK: And I think, I mean they are actually getting there because they do the ANSYS analysis and they look at the stress. And so they find out what the stress is at 800. You know the code wouldn't give you a service temperature of 800 for that material but at 800 it says it can sustain the stress that is being imposed upon it. So, that is how they get the allowable.

MR. PATEL: That is correct. Actually what happened in normal analysis, the one we do for the design basis analysis is A and B level, which is a normal and upset level. That is maximum goes to the 650 by the code. But when you have a

temperature then at least it is going to give you the allowable stress for the higher temperature.

MR. SHACK: I'm getting confused with that. I look at your SE Table 21.4.1 and there is two tables there.

MR. PATEL: Correct.

MR. SHACK: What are the two tables representing?

MR. PATEL: So, one is a surface temperature, which is because --

MR. SHACK: Oh, I see. Okay, I missed the peak surface temperature, peak average wall temperature.

MR. PATEL: Yes.

MR. SHACK: Got it. Okay, finally.

MR. PATEL: That is the standard analysis and then for the ANSYS, you have to pick the average temperature because it cannot take --

MR. SHACK: Right. Well, you could, if you really wanted to spend enough money and time doing it.

MS. GRADY: Anyway, the staff concludes that the methodology and the assumptions in the analysis for determining the temperature source

terms for the hydrogen burns are appropriately conservative and the results are acceptable to be used as input to the structural analysis.

Based on the staff's evaluation of containment survivability, the staff finds the containment integrity is not challenged due to the diffusion flame hydrogen burn from the core makeup tank A in the containment.

CHAIRMAN RAY: Okay.

MR. HABIB: All right, we will move on to the next presentation, then.

This is for the source range flux doubling logic for boron dilution operating bypass. And the reviewer, Jack Zhao, supported by Chris Van Wert, Hien Le, Malcolm Patterson, Marie Pohida, and myself, Don Habib.

I'll turn it over to Mr. Zhao.

Oh, right, one more thing. Just as background, this was the last of the five requests that we did receive from the applicant. We received it last September. We issued RAIs in two areas in November. One, resulted in some changes to technical specifications and the other one dealing with clarification of the logic changes. And that's

it.

MR. ZHAO: Regulatory requirements for this design change is the IEEE 603-1991, which you know is incorporated by reference in regulation 10 CFR 50.55a(h).

Specifically, clause 6.6, actually 603 on operating bypasses requires a safety system to automatically prevent activation of an operating bypass for safety functions if permissible conditions are not met or the safety system should initiate safety functions.

So, in the current design, the operator can manually bypass the flux doubling logic at any time. Also, there was no permissive condition implemented in the safety-related protection and safety monitoring systems for bypassing this safety function.

So, in order to meet the regulatory requirements --

CHAIRMAN RAY: Do we -- excuse me. Do we have any idea why that was the case?

MR. ZHAO: Because --

CHAIRMAN RAY: Did the groundings change, for example?

MR. ZHAO: To meet the regulatory requirements and operating bypass.

CHAIRMAN RAY: Well, I mean but why did it not implement -- why was it not implemented?

MR. ZHAO: Because the operators currently can manually bypass the safety function, it may create a boron dilution event.

CHAIRMAN RAY: Yes. I guess I am not getting my question correctly.

MEMBER STETKAR: Why are they currently allowed to bypass it?

(Simultaneous speaking.)

MEMBER STETKAR: Legally. Why are they legally allowed, according to the certified design, to bypass it at any time? Legally, why are they allowed?

MR. MORRIS: Pete Morris of Westinghouse. The answer is because they have to. There are a certain number of reactor trips and engineering safety features, actuations performed by the protection and safety monitoring system. Some of those are obtrusive to certain normal plant operations that need to occur, either to go up to power, for example, you must block the source range

flux doubling function -- or we go to critical, you must block source range flux doubling or it won't permit you to get there. You have to block the source range reactor trip and then later you get immediate range neutron flux reactor trips or you can't get there.

MEMBER STETKAR: I understand this. And let me stop you right there.

When I was operating back in the late '70s, the trips were automatically reinstated when you exceeded wherever the permissive was. They were. That is not something that has changed with this design or with some new evolution of the thought process, whether it was low pressurized or pressure, or whether it was some sort of low level or, as you mentioned, source intermediate range trips. They were always automatically reinstated.

In this case, apparently, this was not. And that is what I think what Harold was asking and what I am trying to get to is how did we get to the point where this one wasn't made that way.

MR. MORRIS: Okay, there are two subparts to clause 6.6 of 603.

MEMBER STETKAR: Okay.

MR. MORRIS: One has to do with reinstating a protective action when you enter conditions where that protective action is required and the flux doubling logic, along with all the other operating bypasses we have was in complete compliance with the criteria.

MEMBER STETKAR: It was.

MR. MORRIS: The second part, subpart of clause 6.6 has to do with preventing the initiation of an operating bypass, unless appropriate permissive conditions exist. And that was the part of the clause that logic was not in compliance with.

CHAIRMAN RAY: Yes, but was that an oversight or was that a result of applying some logic or some design approach from the past that hadn't been updated with the IEEE standard was change?

What was the origin of it is what I am trying to drive at?

MR. MORRIS: Okay. It was an oversight. IEEE-603 and its predecessor, IEEE-279 have been -- there has been no change. Even going from IEEE-279 to 603, that has not changed. That principle has been well-established since the late 1960s.

CHAIRMAN RAY: Okay, well I am not a control systems guy. So I was just trying to figure out was this a change that we hadn't picked up on or was it just an oversight. Okay.

MR. MORRIS: It was an oversight.

MR. ZHAO: I agree. If you look there is a reason logic diagrams, you can see that the operator can manually bypass this function, resulting in a permissive condition.

CHAIRMAN RAY: Well, and therefore, whoever did the design assumed that is what would be done. You would manually bypass it.

But of course, the IEEE standard has said that it should be automatic. And so now it is going to be made automatic. Okay. And I was just trying to discern is this some new thing that has been required. The answer is no. It has been a requirement all along. Okay.

MR. ZHAO: So, in order to meet the requirements under operating bypasses, the applicant proposes to include a new permissive condition of P-8 to permit bypassing of this safety function.

So P-8 is a setpoint for the new permissive condition is set to 551 degrees

Fahrenheit, the minimum RCS temperature for criticality.

Applicant also proposes to include a logic to force the CVS demi. water isolation valves closed if this safety function is bypassed and also the temperature is below the set point for this new permissive condition.

And a new rest for this safety function is included if there it is bypassed and also if the temperature is below the set point.

The applicant made corresponding changes in tech specs and also Tier 2 sections.

CHAIRMAN RAY: Well, all right, I am still struggling to figure out why, as visible as this would seem to have been, it would have missed being picked up since it included the tech specs and so on, until this point in time.

MR. ZHAO: The logic was -- my personal view of it it was an oversight.

CHAIRMAN RAY: Well, but an oversight that was an oversight on more than just one design engineer, it seems like. Because like I say, correcting the oversight requires changes to the tech specs.

MEMBER STETKAR: Harold, I suspect, and this is only my own personal suspicion is that this particular protection function is unusual. It is not every design has it, this automatic protection against dilution. And it is something that applies primarily -- not just primarily -- entirely to dilution events that occurred during plant shutdown conditions.

So, you have got an operating mode where people haven't traditionally paid as much attention to automatic safety functions, if you will, that being shutdown, and a design that is, from several of the plant designs I have looked at, somewhat different, actually kind of innovative of protecting against one way of getting a reasonable amount of pure water into the system.

And you know I think you can walk your way into why somebody didn't think about this in the same context as we think about all those other things that I was talking about, whether it is source intermediate range trips or whether it is pressurizer pressure level, or cooldown rate, or high steam flow, or the type of thing that people block and reinstate for traditional safety-related

at-power protection functions.

So I can sort of see how maybe it happened. And again, that is personal conjecture but it is different.

CHAIRMAN RAY: All right. Well, that's helpful. Thank you.

MR. ZHAO: So, in conclusion, the staff found the proposed changes acceptable. The changes meet the criteria on the operating bypass in the IEEE 603. And that is all for me. Thanks.

CHAIRMAN RAY: Thank you. Any other questions on this topic?

Okay, Don, what more do you have?

MR. HABIB: I think we are finished for the day.

CHAIRMAN RAY: Perhaps. But under the circumstances that you acknowledged at the beginning of the day, we shouldn't waste any available time here in making as sure as we can be that we are prepared for what remains ahead of us.

So, we will be going around the table here before we end. But before we do that, and I, of course, will ask for public comments. In fact, can we open the lines so that we can do that here

shortly?

But we want to make sure that we don't miss any opportunity that exists at present to readdress any questions that are on any of the members' mind or make any statements that has occurred to any of our folks making presentations that they would like to add to what has been said earlier. Because it is important that we take advantage, as I said, the time given of what we have yet to do.

The line is open. So, I am going to ask if there is anyone on the phone line who would like to make a comment. We don't engage in questions and answers but we welcome and encourage any comments that people would wish to make. Are there any such?

Hearing none, I will ask if there is anyone here in the meeting room who would like to come to the microphone and similarly make a comment to the subcommittee. Okay, I hear none of that.

We can close the line at any point here, Peter. And we will then go around as usual and get final inputs from our consultant and members.

We will be making a dramatically shortened presentation to the full committee, which

will then provide the basis for a decision to be made about our readiness to prepare a letter. We will assume that we will conclude that we are prepared to do so. And then it will be up to me then to propose a draft of such a thing.

With that in mind, I would ask you to consider whether there is anything that we feel would, if added to at this point in time, any member thinks that we really need this or that in order to enable us to prepare and process a letter yet this week, please do say so now. And if it occurs to you later, why, let us know then, too.

With that, I will first ask our esteemed consultant, Bill Shack to make any comments. He is going to think about his report as he flies home tonight and send something to me when he gets up in the morning. So, I am not asking for you to do that, Bill, but is there anything that you would like to say now to the members?

MR. SHACK: Just one question, again, back to the condensate return and the experimental stuff. I'm looking back at the minutes for the September 17, 2014 meeting and they are talking about Phase 1 testing providing input to these

things. Is the Phase 1 testing discussed there new testing that meets your quality standards or is that the old AP600 testing?

MR. PFISTER: This is Andy Pfister. The Phase 1 testing was the testing Tom and Ryan discussed during the presentation today with respect to the testing that was done in the 2013 time frame, looking at losses off the shell.

MR. SHACK: Okay. Was there Phase 2 testing?

MR. PFISTER: So, we did conduct Phase 2 testing. That wasn't utilized for the license submittal. Phase 2 testing looked at I will call it margin recovery to look at more discrete testing to potentially enhance, to take additional -- to demonstrate that our losses were less, based on a more detailed test.

We completed that testing. Testing was successful and generally showed that we could have credited a lower return fraction -- higher return fraction. But it was unnecessary to implement.

MR. SHACK: Okay. Well, again, that was the most difficult of these things to look at. And it is good to hear that there is more experimental

information. I guess I would have liked to have seen somewhat more detail on the testing, even the 2014 didn't really have very much. They just kind of stated results.

And the other changes seem to me, you know clearly these are all improvements. And to that point, they are acceptable.

I am beginning to understand the differences between the analyses used for the safe shutdown and the Chapter 15 and why the assumptions are different. And I will discuss that a little bit more in my write-up but it is a little bit more detailed here.

But other than that, I don't have any particular comments to make.

CHAIRMAN RAY: All right. Well, I would just draw from that that anything that can be squeezed in on the full committee presentation that speaks even briefly to the issue of testing as a basis for what you are relying on at this point in time, don't expect to have a dog and pony show about testing but it is -- because I tend to differentiate between the AP600 days and what is now the case and haven't explored in detail what was done in 2013 and

since, in terms of Phase 1 and Phase 2 and so on.

But that said, then anyway, thank you, Bill.

Joy, I will start with you and then go around the table.

MEMBER REMPE: I don't have any concerns about the changes. I appreciate everyone's presentations.

I am interested a little bit, I guess when I see this, I can't help but think about what a certified design is and some of the other discussions we hear with the advanced reactors and some of the things that they are requesting for initial confirmation.

Yesterday, we heard about the digital I&C and people wanting something earlier for initial confirmation. And I think that that is an interesting discussion and I think this is a good example of maybe the downside of have more confirmation earlier. And I just had to bring that up out of an observation. Thanks.

CHAIRMAN RAY: Yes, there certainly are, I have alluded to it as well, a generic call them lessons learned or generic implications of what we

are looking at here.

Of course we have got to, for the letter purposes, got to stay focused on what is actually before us here. But we do have a responsibility to think more broadly and that is part of the bigger picture that we will try and address without causing a hang-up in what is immediately before us here. And we will probably want to talk about that some more outside the context of leaving.

Charlie?

MEMBER BROWN: I don't have any additional comments.

CHAIRMAN RAY: John?

MEMBER STETKAR: I don't have anything more. I thought that the presentations covered everything.

I think my only comment is I would reiterate for the staff that I was bothered by that conclusion that the changes have not affected the risk of the plant because I think that there probably is uniform agreement that they have reduced the risk of the plant and the PRA just got it -- the design certification PRA just got it wrong. So, I don't know whether the staff wants to reconsider

that, the format in which that conclusion is presented up front in the SER or not.

That's the only thing I can think of.

CHAIRMAN RAY: Dennis?

MEMBER BLEY: Nothing more for me, Harold, thanks.

CHAIRMAN RAY: Mike?

MEMBER CORRADINI: Nothing.

CHAIRMAN RAY: Dick?

MEMBER SKILLMAN: Yes, I have got just one comment. And we have touched on it gently several times but I think it is worth entering into the record. It is the issue of the generic implications on design control of a conceptual design with a tenet discipline for configuration control of that conceptual design.

So, what I am really saying is we have got this conceptual design that is moving ahead and it appears to be robust and strong but it is only as robust and strong as the configuration control of all the pieces that are part of it.

For my money, these five things that we have spoken about today are issues because of that. The design is proceeding. It is conceptual in part

but there is a configuration control component that needs to go along side that ensures that all of the pieces fit.

That is my comment. Thank you.

CHAIRMAN RAY: Pete.

MEMBER RICCARDELLA: No, I don't have anything further.

CHAIRMAN RAY: And Ron?

MEMBER BALLINGER: No, I don't have anything to add either.

CHAIRMAN RAY: Well, in the same way that John had concern about something said in the safety evaluation, I have shared with many of you the concerns I have about phrases like not necessary to achieve the underlying purposes of the rule and so on, which are in the safety evaluation. There is things there that I find troubling, too, but I don't think they can be folded into what we are trying to achieve here, which is are these changes ones that we can support making in connection with Levy and whatever observations we want to make about other plants where we believe they can apply as the safety evaluation says.

So, we will work on that and try and

keep focused, I will at least, in terms of the scope of a letter. But bearing in mind that there may be more that we have learned here or information that we have gotten here that we need to find some way to address ourselves to.

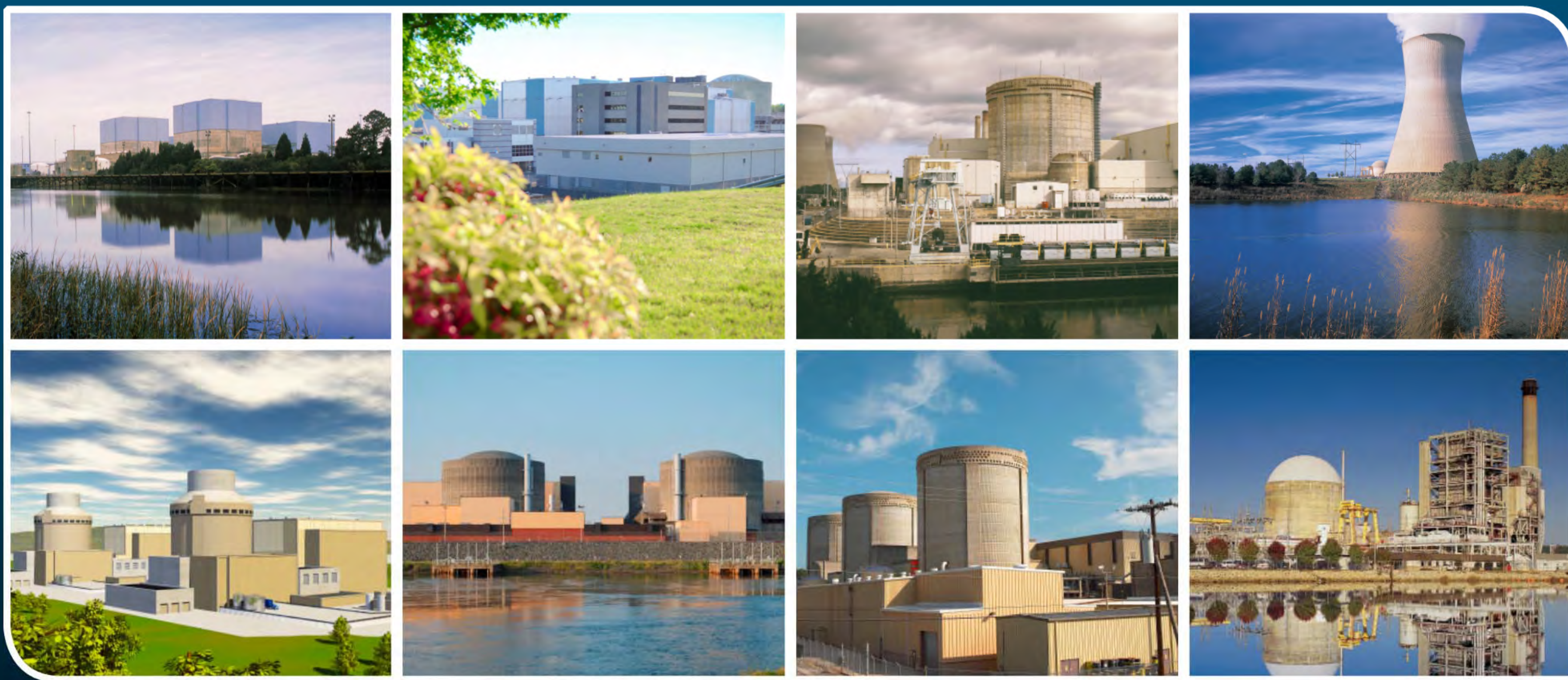
I want to say that I think that each of the parties have come before us here, Westinghouse, Duke, and the staff, have all done amazing work on a collection of very disparate, and as the person drafting the letter, let me tell you they are each individually different items which you go down into the weeds in a lot of depth but there is no really readily recognizable way of tying them altogether, other than to say well, these things are going to happen and may continue to occur over time.

But that each of them have been addressed by the three groups presenting to us I think very, very well, candidly in the terms of the issues like Appendix B application. And I certainly share in my colleagues' expression of appreciation for all the work that has been done.

With that, if there is nothing more, I will adjourn the subcommittee meeting. Is there anything more?

Hearing nothing, we are adjourned.

(Whereupon, the above-entitled matter went off the record at 4:23 p.m.)



Levy COLA – ACRS Review

AP1000 Generic Issues

DUKE ENERGY®

Agenda
Levy COLA – AP1000 Issues Review

- Morning Session
  - Condensate Return

- Afternoon Session
  - Post Accident MCR Operator Dose
  - Hydrogen Venting inside Containment
  - Source Range Monitoring/Flux Doubling
  - MCR Heat Up

April 5th, 2016

Bob Kitchen – Duke Energy
Andy Pfister - Westinghouse

AP1000® PXS Condensate Return

- Overview and update
  - Summary of design change
  - Why change is required
  - Licensing basis for Passive Residual Heat Removal
  - Update from previous ACRS meeting

<u>Closed Session</u>

- Review of supporting analyses –Design basis analyses
  - Safe shutdown and long term cooling analyses
  - Revised calculation models
  - PRHR heat transfer model and validation
- Plant recovery

QA Program Implementation and Technical Oversight

10CFR50 Appendix B Implementation

- COLA Development
  - Duke QA Program (ANSI N45.2) applies
  - Vendor QA programs approved and monitored by Duke
  - Change to DCD (Departure/Exemption)
    - Westinghouse develops change
    - Duke reviews and approves implementation of change
  - Licensing basis change implemented by departure and COLA revision

- COL Issuance
  - Duke QA Program (NQA-1)
  - Licensing basis change implemented by License Amendment

QA Oversight Activities

- NUPIC AP1000 Full Scope Audit of QA Program and Implementation Every 2 Years
- NUPIC AP1000 Limited Scope Audit Every 2 Years
  - Alternate with Full Scope Audit
- Semi-annual Performance Based Evaluation. Based on results of:
  - NUPIC Activities & Audits
  - Source Surveillances or Inspections
  - Procurement Receipt Activities, and
  - Supplier Problems Identified by Internal and External Sources
- Owner acceptance reviews performed for vendor initiated changes when implemented
- ISG-11 evaluations completed for Design Change Proposals

Lessons from Condensate Return

Areas for improvement in Duke oversight of Westinghouse

- The issue was not promptly entered into the Duke Corrective Action Program
- Initial reviews of Westinghouse technical products were not effectively structured or documented
- Initial Duke reviews did not challenge Westinghouse significance determination or need for extent of condition
- Duke did not effectively leverage NUPIC to examine Westinghouse response to Condensate Return and similar issues

Corrective Actions

- Procedures now require condition report for any change that exceeds ISG-11 criteria
- Engineering develops focused review plan of change and supporting documents
  - Review plans documented and approved
  - Reviews include significant interaction with Westinghouse SMEs
  - Supporting calculations and analyses are reviewed in detail
  - Final report written to document satisfactory completion of review
- Review of WEC corrective actions include extent of condition and Part 21 evaluation
- Manager, Vendor Quality is notified of emergent issue and corrective actions for incorporation in NUPIC – Westinghouse audit

Westinghouse Corrective Actions and Extent of Condition

- Root Causes
  - Insufficient design requirements flow down
  - Insufficient interface control between plant design and analysis
- Corrective Actions
  - Developed analysis design plans to document input sources, complete analysis scope, and identify key interfaces with other design elements
  - Developed/strengthened engineering interface control documentation to communicate requirements between analysis and design organizations
  - Extended safety analysis input database to cover Chapter 19E analyses
- Extent of Condition Findings
  - Prior to formal extent of condition, s analysis baseline update completed. Reconciled multiple input and assumption discrepancies:
    - Aligned SBLOCA and LBLOCA minimum backpressure multiplier
    - Aligned inputs between containment analysis and transient analysis
    - Generated more rigorous analysis basis for abnormal events
  - MCR Dose: failure to account for filter contribution, non-limiting SG blowdown assumption
  - Condensate Return: identified need for a benchmark analysis model

Westinghouse

Reason for the Design Change

- Previous analysis performed during design certification assumed a constant condensate return rate of 90%
- Investigations resulting from validation of this assumption determined the 90% return rate could not be met.
  - A result of as built design configurations that were different than testing used to establish the 90% return rate
- The safe shutdown temperature criteria in SECY-94-084 of 420°F in 36 hours could not be met with the calculated value of return rate without modifications.
- Without the design enhancements, ADS actuation would have been sooner following a non-LOCA event. Adequate core cooling would have been maintained

Summary Of Design Change

- The following plant changes have been incorporated to increase condensate return to the IRWST
  - Add downspouts to polar crane girder and internal stiffener to drain condensate directly to IRWST
    - Minimizes losses associated with re-attaching flow to containment wall and with flow over support plates
  - Optimize IRWST gutter design and location
    - Extended to collect above upper equipment hatch and personnel airlock
  - Changed routing of cables to hydrogen sensors
    - Reduces quantity of support plates (obstacles) attached to the containment dome
  - Would not have been met without design changes

GDC-34 Requirements

- A residual heat removal (RHR) system must be provided to remove residual heat from the reactor core so that specified acceptable fuel design limits (SAFDLs) and the design conditions of the reactor coolant pressure boundary are not exceeded
- Requires suitable redundancy of the components and features of the RHR system to ensure that the system safety functions can be accomplished, assuming loss of offsite or onsite power, coincident with a single failure.

SECY 94-084 states:

- 420°F is a safe, stable condition for passive plants.
- Other plant conditions constitute a safe, stable state as long as reactor subcriticality, decay heat removal and radioactive materials containment are properly maintained for the long term.
- Passive system capabilities can be demonstrated by appropriate evaluations during detailed design analyses, including
  - A safety analysis to demonstrate that the passive systems can bring the plant to a safe, stable condition and maintain this condition and
  - No transients will result in the specified acceptable fuel design limits and pressure boundary design limit being violated

Safe Shutdown
AP1000 - DCD Revision 19

- AP1000 DCD revision 19 has inconsistencies
  - Section 6.3.1.1 “Safety Design Basis” describes PRHR closed loop, “…capability to establish safe shutdown conditions, cooling the reactor coolant system to about 420°F in 36 hours.”
  - DCD analysis that demonstrates 420°F in 36 hours is not a design basis analysis
- AP1000 DCD revision 19 supporting analyses demonstrate
  - Design meets GDC-34 requirements using Design Basis Analysis (Chapter 15) assumptions
  - Design achieves 420°F in 36 hours using conservative, non-bounding assumptions performance analysis
- Design description revised to establish clear separation of safety design basis from non-safety design features (Performance goal)

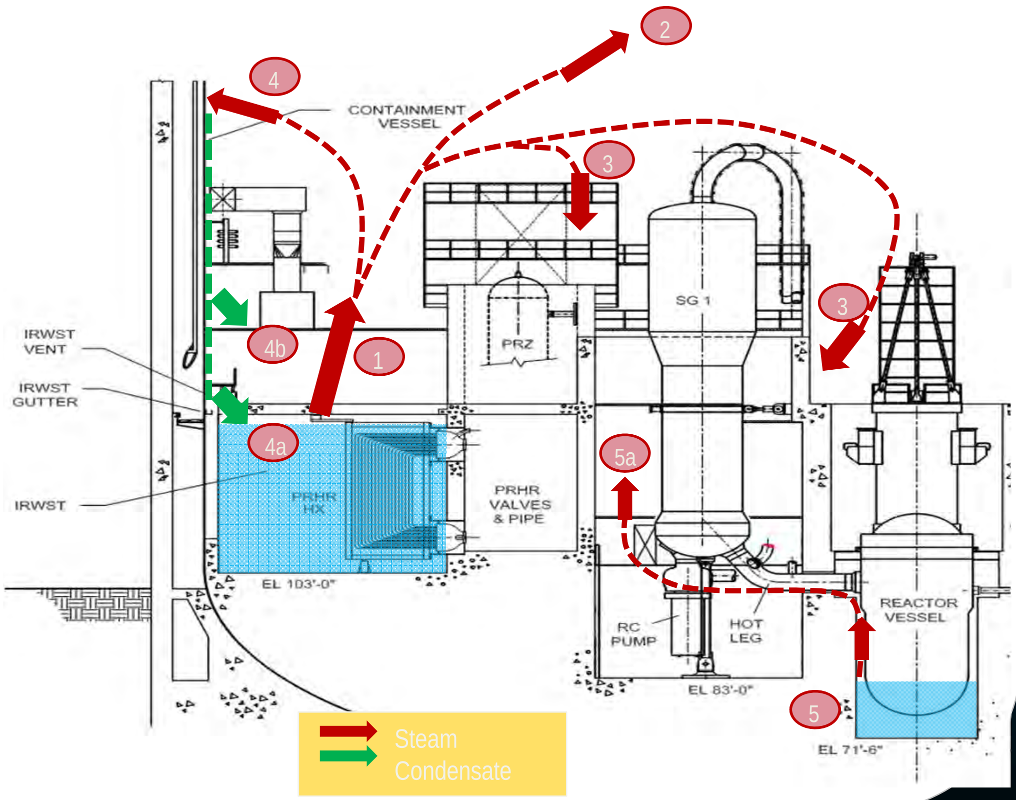
- PRHR safety design basis
  - Remove sufficient decay heat for at least 72 hours to maintain acceptable reactor coolant conditions following a non-LOCA event
- Non-safety design basis (License performance goal)
  - Establish reactor coolant temperature of 420°F in less than 36 hours
  - PRHR HX can maintain 420°F for greater than 14 days in closed loop operation

Summary of Licensing Basis Change

DCD Revision 19	Levy FSAR
1. For non-LOCA events, PRHR performance meets all Chapter 15 analysis requirements	1. FSAR Chapter 15 Design Basis Accident analysis extended to 72 hours
2. Safety design requirement that PRHR cooling can achieve safe shutdown in less than 36 hours.	2. No change in analysis method. FSAR clarifies that this is non-safety design requirement based on conservative, non-bounding analyses
3. PRHR cooling can maintain safe shutdown (SSD) indefinitely.	3. FSAR identifies that PRHR closed loop cooling can maintain SSD for greater than14 days based on conservative, non-bounding analysis

Where Does IRWST Steam Go?

1. Steam leaving IRWST
2. Pressurizes containment
   a. Lost from IRWST
3. Condenses on walls, floors, structures
   a. Lost from IRWST
4. Condenses on CV
   a. Most collected and returned to IRWST
   b. Some splashes / spills off
5. Losses from IRWST collect under RV, contact hot RV
   a. Steam rises up into cont.



- Overview of the Issue
  - Analysis approach
  - Empirical data used to determine losses
- Key Developments since Previous Meeting
  - Calculation Discrepancies identified in January 2015
    - Required analysis approach and calculations to be modified – WGOTHIC replaces PRHR Performance Calculation
    - RCA Performed
    - PIRT performed on use of LOFTRAN for long term duration

DUKE ENERGY®

Operational Considerations

Larry Taylor – Duke Energy

OPERATIONAL CONSIDERATIONS

- Operator Actions at the end of 72 hours if AC Power has <u>not</u> been restored on site:
  - Ancillary Diesel Generators power control room system indications and PCS Recirculation Pumps
  - Makeup to the PCCWST from the PCCAWST
  - Monitor parameters for acceptable RCS cooling capability, continue PRHR HX heat removal and continue efforts to restore power

  Note: Safety-related connections are provided to connect portable equipment to replace ancillary equipment if necessary.

- Operator Actions at the end of 72 hours if AC Power has not been restored on site (continued):
  - When RCS cooling capability parameters depart from acceptable values, initiate RCS depressurization via ADS, stages 1, 2, 3 and 4.
  - After ADS Stage 4 valves open, IRWST injection valves and recirculation valves from the containment sump will open.
  - During RCS depressurization, CMTs and Accumulators will discharge into the RCS. RCS pressure and temperature will decline and heat transfer from inside containment to outside containment will continue.

- Operator Actions if AC Power is restored (by Standby DGs or off-site power) with PRHR in service:
  - Re-establish feed flow to the Steam Generators and begin a slow RCS cooldown with steam exhaust to atmosphere or condenser
  - Restore makeup to the RCS using Makeup Pumps
  - When RCS Temperature is <350 degrees, place normal decay heat removal system (RNS) in service
  - Continue RCS cool-down

Main Control Room Dose

Aaron Wilmot – Westinghouse
Jim Thornton – Duke Energy

Westinghouse

Post-Accident Main Control Room Dose

Background:

- The ***AP1000*** main control room (MCR) operator dose requirements are met by the safety-related main control room emergency habitability system (VES)
- DCD Chapters 6 and 15 present operator dose analyses and results for a range of design-basis accidents

Problem Statement:

- The certified design did not include direct dose contributions from the VES filter unit: direct filter dose increase the operator dose when considered
- The Main Steam line break analysis did not model the most limiting release scenario: secondary side coolant release timing assumptions were non-bounding
- Discrepancies were identified in the underlying shielding calculations for post-accident operator dose: AP1000 shielding design non-conservatively differed from the analysis model

Issue Resolution:

- A combination of design and analysis changes were needed to demonstrate operator doses satisfy General Design Criterion (GDC) 19

Summary of Proposed Changes

- Changes encompass modifications to the physical plant design, I&C, technical specifications, and analysis changes
- Changes include:
  - The addition of a VES Filter shield plate below the filter unit and inclusion of calculated shine components in the operator dose calculations
  - Update and refinement of MCR HVAC intake radioactivity concentration setpoints and logic
  - Decrease in Technical Specification value for secondary side dose equivalent iodine (reduction to 10% of standard value)
  - Refinement of MCR direct dose radiation transport calculations to accurately reflect the AP1000 shielding design
  - Rod Ejection Accident methodology changed to reflect current SRP Section 4.2, R3 methodology
  - Changes reflecting refinements in AP1000 detailed design and associated safety analyses

Analysis Margin (Main Control Room Dose)

- The MCR Operator Dose analysis uses conservative assumptions and inputs
  - A core melt source term (RG 1.183) is applied
  - Direct Dose analyses considers maximum dose rate locations inside the MCR rather than average and neglects plant SSCs, including rebar and structural steel
  - Standard plant χ/Q values are applied and bound site-specific values (increasing airborne dose)
- Margins are maintained
  - The revised safety-related MCR Dose analysis provides more margin than the certified design

    4.33 rem vs. 4.41 rem
  - Defense in depth analysis demonstrates that MCR operator dose is <5 rem even if only the non-safety VBS is operating

Westinghouse

Hydrogen Venting Inside Containment

James Scobel – Westinghouse

Reason for the Change

Background:

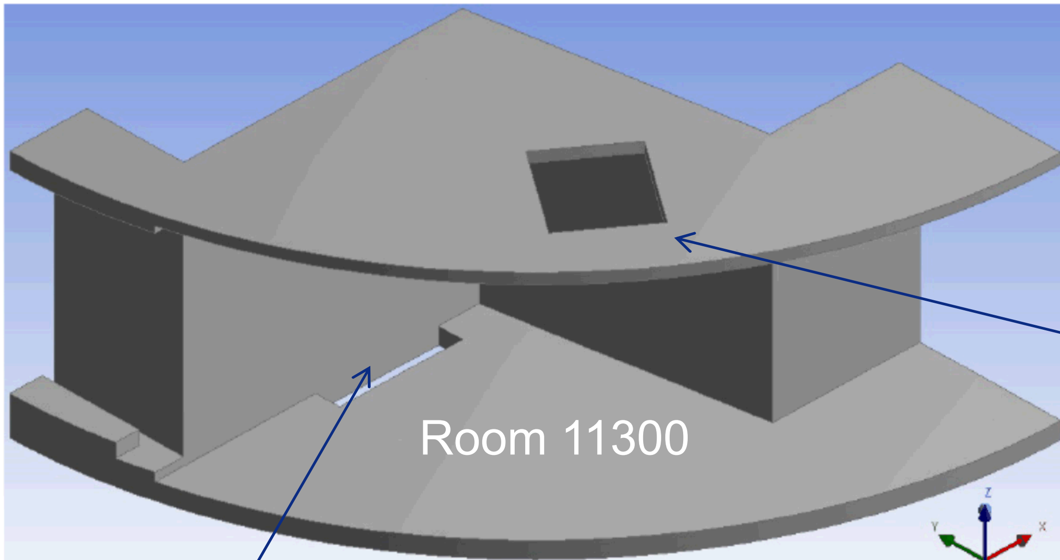
- For severe accident mitigation, AP1000 containment hydrogen control system (VLS) is designed to promote hydrogen burning soon after the lower flammability limit is reached.
- The design of the PXS and CVS compartments (Rooms 11206/11207 and 11209) allows for venting of hydrogen into Room 11300 above.

Concern:

- AP1000 design changes to containment layout were implemented without revision to supporting analyses for hydrogen diffusion flame
- In one particular severe accident scenario (frequency = 6E-9/yr), a hydrogen diffusion flame may create a locally high temperature near containment pressure boundary, hatch and penetrations
  - Analysis required to verify a containment survivability
  - ITAAC revision is required to reflect containment layout design changes

Westinghouse

PXS-A Compartment (Room 11206) Vents

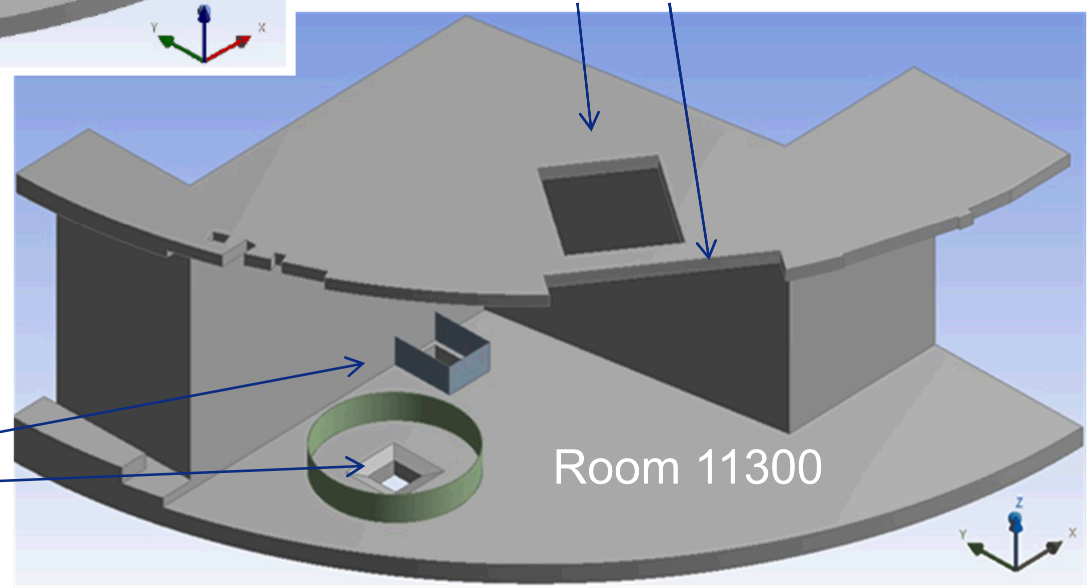


<- Original layout

Vents in Ceiling of 11300 to Upper Compartment

Vent from 11206

Final layout ->



Vents from 11206

Westinghouse

Summary of Analysis Required to Support Change

- Hydrogen source term to PXS compartment
  - Double-ended direct vessel injection line break with matrix of ADS valve success configurations to define worst H_2 source term
  - MAAP4.0.7 analyses
- CFD Analysis of the H_2 plume burning and containment shell heatup
  - Identified that layout changes potentially introduced new phenomena that created a worse condition than previously analyzed
- "Simple" H_2 burning plume and containment pressure boundary heat transfer analysis of shell, equipment hatch cover/seals to calculate maximum temperatures and temperature distributions on containment pressure boundary
- Structural evaluation of the containment survivability demonstrated containment integrity for all components
  - Eigenvalue buckling analysis
  - ASME Service Level C stress evaluation

Westinghouse

Conclusions

	Peak Surface Temperatures °F (°C)			
		<---- Temp Distribution for Structural Analysis --→		
Component	Maximum Hot Spot	Hot Spot Allowables	Zone 1 Convection and Radiation	Zone 2 Radiation Only
Cnmt Shell	585 (307)	650* (343)	470 (243)	436 (224)
Insert Plate / Hatch Barrel	439 (226)	488** (253)	366 (186)	344 (173)
Hatch Cover	741 (394)	800 (427)	591 (310)	543 (284)

* Allowable max temp limit from ASME code for SA 738 Grade B

** Allowable max temp limit for hatch barrel corresponding to accept criteria for EPDM rubber

- Structural analysis performed for 2 temperature distributions on the containment demonstrates success of the pressure boundary integrity

Reasonable assurance of containment vessel survivability during a hydrogen diffusion flame event is demonstrated

Westinghouse

Description of licensing change

- Revised ITAAC (Tier 1 Table 2.3.9-3)
  - Updated the minimum distances requirement between openings and the containment shell to reflect the actual geometry, including tolerances

- Supporting Subsections 6.2.4.5.1 and Section 19.41.7 also updated.

Flux Doubling Algorithm Compliance with IEEE 603

Peter J. Morris - Westinghouse
Larry Taylor – Duke Energy

Westinghouse

Reason for the Change

- Flux doubling algorithm protects against inadvertent criticality due to boron dilution during shutdown conditions
  - Isolates dilute water sources to the reactor coolant system
- Non-compliance was identified to one subpart of IEEE 603 for the logic associated the algorithm
- The design did not comply with a portion of IEEE 603 Sub-clause 6.6 criteria:
  - Whenever the applicable permissive conditions are not met, a safety system shall automatically prevent the activation of an operating bypass or initiate the appropriate safety function(s).

Operator could block flux doubling logic without an appropriate permissive

Description of change

- A new permissive, P-8, based on minimum required reactor coolant temperature for criticality (MTC), was added to satisfy the IEEE 603 Sub-clause 6.6 criteria:
  - P-8 setpoint is at TAVG of 551°F
- Operators can still initiate operating bypass (“Block” in Westinghouse terminology) for flux doubling algorithm at any time:
  - Above P-8 setpoint, operators can control both control rods & boron concentration change for reactivity adjustment
  - Below P-8 setpoint, safety system overrides isolation valves from the demineralized water system closed
    - Prevents boron dilution event

Westinghouse

Operational Impacts

- Operators must verify P-8 permissive status prior to blocking Flux Doubling when preparing for the approach to criticality during reactor startup
  - Operating procedures direct operators when to block Flux Doubling after P-8 is verified to be satisfied
  - Permissive status indications are available on both safety displays and normal operator workstations
  - Operators train extensively on reactor startup procedures and the approach to criticality
- Ability to block flux doubling logic below P-8 setpoint needed to prevent unnecessary Boron Dilution Block actuations during control rod testing during shutdown conditions
  - Isolation valves to the demineralized water system will be overridden closed and prevent a dilution event

Main Control Room Heat Up

Jonathan Durfee - Westinghouse Electric Company

Larry Taylor – Duke Energy

Westinghouse

Reason for the Change

Background:

- The ***AP1000*** main control room (MCR) air temperature must remain at or below the defined limits during operation of the main control room emergency habitability system (VES)

Problem Statement:

- Throughout the design evolution of the MCR, the size and quantity of equipment have increased, raising the total MCR heat load. These increases result in a MCR temperature response exceeding the current licensing basis limit and equipment qualification conditions
- A new more limiting transient where non-safety power is provided to non-safety equipment but VBS is NOT available was identified

Description of change

Two stage automatic load shed

- This automatic operation is proposed to maintain the required MCR environmental conditions
  - Only select non-safety loads are de-energized, with no impact to the minimum inventory of displays / controls provided by the primary dedicated safety panel
  - No impact to the plant controls and indication of plant parameters at operator workstations
  - Load shed circuitry is safety related

Additional Surveillance Requirements

- Limit initial conditions for adjacent rooms in the updated MCR Heat Up analysis
- Limit moisture content for air in the VES storage tanks

Human Factors Considerations

- Analysis supports unlimited operator stay time at a WBGT Index of 90°F
  - Acceptance criterion is from NUREG-0700
  - Same limit is met for post-72 hour ancillary fan operation

Westinghouse

Summary of Analysis Required to Support Change

- Updated GOTHIC Model
  - MCR Model was refined to show greater resolution
  - Heat loads distributed to reflect as-designed layout
- Surveillance requirements verify assumptions are bounded
- Extended Post-72 hour model based on described VBS operation

Presentation to the ACRS Subcommittee

Staff Review of AP1000 Design Changes and Departures in the Levy Nuclear Plant Combined License Application

Overview

April 5, 2016

Overview – Levy COL

- Levy COL staff interaction with ACRS 2011
  - Letter of conclusion and recommendations

- 2012-2016 staff review of additional applicant submittals
  - Key chapters of advanced safety evaluation issued or re-issued

Topic	Advanced SE	ARCS Meeting
AP1000 Departures	Chapter 21	April 2016
Condensate return design change	Section 6.3 (Chapter 21)	September 2014
Fukushima recommendations	Chapter 20	January 2013
Bulletin 2012-01	Chapter 8	Not planned
Emergency preparedness enhancements	Chapter 13	Not planned

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Overview– Levy Departures

- DEF identified **6** departures that require review prior to Commission decision on issuing COL

- Addressed in separate Chapter 21
  - 21.1. Condensate return (2 departures)
  - 21.2. MCR Dose
  - 21.3. MCR Habitability (Heatup)
  - 21.4. Combustible Gas Control in Containment (Hydrogen Vent ITAAC)
  - 21.5. Source Range Flux Doubling Logic for Boron Dilution Operating Bypass (IEEE 603-1991)

Presentation to the ACRS Subcommittee

Staff Review of Changes to AP1000 Passive Core Cooling System Condensate Return Section 6.3

April 5, 2016

Staff Review Team

- Boyce Travis
  - Containment and Ventilation (presenter)
- Tim Drzewiecki
  - Reactor Systems (presenter)
- Yiu Law
  - Mechanical Engineering
- Derek Scully
  - Technical Specifications
- Don Habib
  - Project Management

Outline

Summary of staff review

- Licensing impact
- Review history
- Staff findings

Updates since last meeting

- Calculation revisions
- Ambient heat losses
- Transition to open loop cooling

ACRS questions from previous meeting

- Testing and Analysis
- Policy

Conclusions

Vendor inspection

Outline

Summary of staff review

- Licensing impact
- Review history
- Staff findings

Updates since last meeting

- Calculation revisions
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Conclusions

Vendor inspection

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Licensing Impact

- Design change includes exemption request and two departures from AP1000 DCD Revision 19
  - Departure 3.2-1
    - Modifications to the polar crane girder, internal stiffener, and passive core cooling system (PXS) gutters
  - Departure 6.3-1
    - Changes DCD PRHR-HX capability to maintain safe shutdown for non-LOCA events from “indefinitely” to 14 days (72-hour safety-related mission time)

- Levy FSAR/DCD chapter and section changes
  - 3.2, 3.8, 5.4, 6.3, 7.4, 9.5, 14.3, 15, 15.2.6, 19, 19E and technical specification bases (Chapter 16)

Review History

- April 2013 - Formal submittal (Levy departure and exemption request)
- May 2013 - NRC staff audits condensate flow test plan. Staff terminated the audit for lack of calculation reports.
- Jan./Feb. 2014 - Staff begins second audit, issues first round of RAIs concerning supporting analysis under audit.
- September 2014 - Staff finalizes safety evaluation, ACRS meeting, subsequently informed by the applicant of errors in the calculation
- August 2015 - Staff finishes review of revised calculation methodology
- September 2015 - Staff advised by applicant of potential loss of subcooling
- February 2016 - Advanced SE finalized

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Staff Findings—Containment Impact

- Containment peak pressure unchanged, due to conservatisms inherent in that analysis
- Potential lowered IRWST level following PRHR HX actuation does not challenge actuation of ADS 1/2/3
- Containment floodup level (in the event of containment recirculation) following actuation of ADS stage 4 or LOCA not adversely affected
- Calculated condensation return rate of approx. 80% in the long term based on testing and analysis is acceptable
    - This value is roughly the fraction of condensate returning to the IRWST that reached the containment shell
    - In the early stages of the transient, the return rate is significantly lower, and this is captured in the applicant's analysis

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Staff Findings—
Passive Core Cooling System

- Chapter 15 analyses are not affected
  - Bounding analysis described in FSAR Section 6.3.3.2.1.1
  - Analysis demonstrates non-LOCA Chapter 15 acceptance criteria for satisfied for at least 72 hours
  - Results consistent with NRC staff confirmatory analysis

- Condensate return rate is sufficient to meet cooldown requirement of reaching 420 ˚F in 36 hours
  - Demonstrated via a non-Chapter 15 analysis
  - Consistent with NRC staff confirmatory analysis

- Transition to open loop cooling is retained as defense-in-depth

Outline

Summary of staff review

- Licensing impact
- Review history
- Staff findings

<u>Updates since last meeting</u>

- Calculation revisions
- Ambient heat losses
- Transition to open loop cooling

ACRS questions from previous meeting

- Testing and Analysis
- Policy

Conclusions

Vendor inspection

Calculation Revisions

- Previous method involved four calculations with spreadsheet interfaces

- New method more streamlined – two iterative calculations:

  - **Calc. 1**: WGOTHIC containment response
    - Models containment + PCS; no RCS (heat source in IRWST and cavity)
    - Incorporates calculated wall losses, separating condensate lost from wall (goes into containment) from condensate returning to IRWST

  - **Calc. 2**: LOFTRAN
    - Calculates 72 hour system behavior
    - Demonstrate $T_{ave} < 420$ °F in 36 h (using BE assumptions)
    - Provides bounding values (DB+ assumptions) to Calc. 1 for decay heat to IRWST, temperature of reactor vessel

- No impact on previous findings

Ambient Heat Losses

- September 2015, the applicant made staff aware of the possibility for a loss of RCS subcooling during a non-LOCA event
- Ambient heat losses, which were previously not considered, could reduce pressure and temperature in the RCS to the point that the system becomes saturated.
- Applicant evaluated:
  - Potential for loss of subcooling
  - PRHR HX performance under saturated RCS conditions
- Staff audited the calculations for:
  - Calculation of heat losses
  - Performance of PRHR HX under saturated conditions

Heat Loss Through Pressurizer

- Primary heat loss concern from RCS is through pressurizer
  - Has insulated and uninsulated surfaces
  - The uninsulated surfaces (supports, heater sheaths) account for almost half of the heat losses through the PZR under certain conditions

- Analyses performed to justify effective heat transfer coefficient (HTC) applied to PZR outer surface in RELAP5 and LOFTRAN
  - Effective steady-state HTC conservatively bounds transient conditions
  - Modeling of PZR heat losses is conservative:
    - Consistent with NRC staff calculations
    - Supported by data from literature

Heat Loss Through Pressurizer

- Staff confirmatory analyses indicate a further margin of 50% could be applied to the heat losses and have the RCS remain subcooled for a minimum of 72 hours

- Multiplication factors used to account for heat losses beyond through-insulation heat loss are supported by data from literature
  - Laboratory testing showed through-insulation ranged from 28% to 52% of total heat loss
  - Convective air flow will be reduced significantly during SBO

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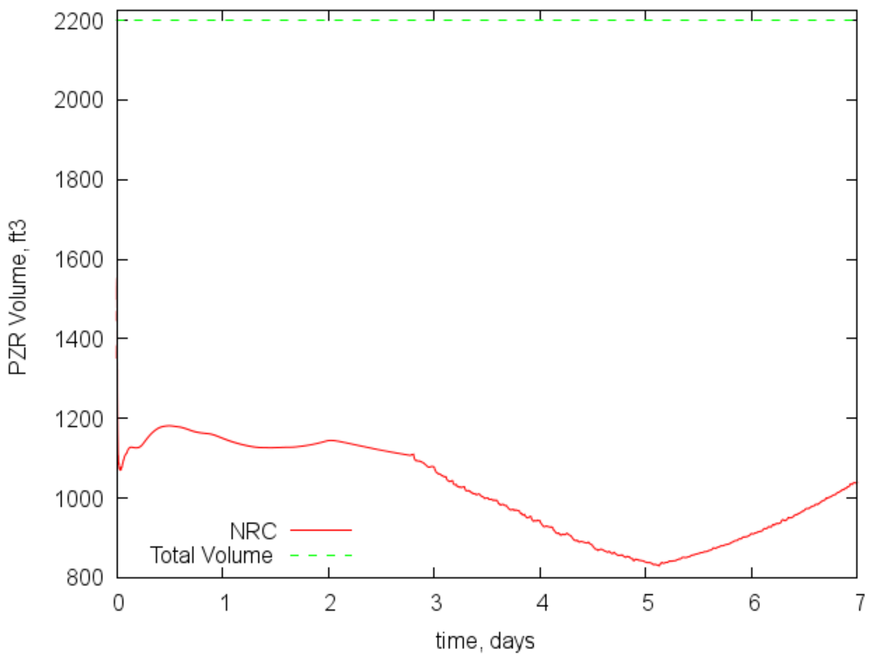
Loss of Subcooling Transient Analyses

- DBA analyses show loss of subcooling does not occur within 72 hours
  - Ambient heat losses do not adversely impact Chapter 15 DBA analyses
  - Consistent with staff confirmatory analysis

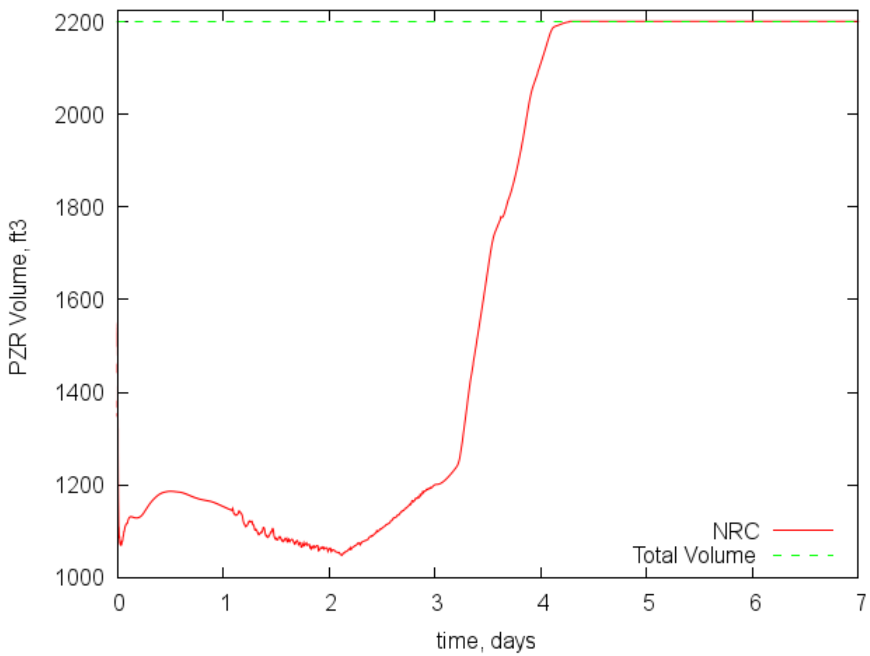
- No adverse impact to safe shutdown analysis (420 F in 36 hours)

- Analyses show loss of subcooling occurs within 14 days
  - PRHR HX performance does not degrade
  - Supported by test results from APEX facility (NRC SBO testing for AP600 and AP1000)
  - Consistent with staff confirmatory analysis

Loss of Subcooling Transient Analysis



h = 2 W/m^2-K (0.35 Btu/hr-ft^2-F)



h = 5 W/m^2-K (0.88 Btu/hr-ft^2-F)

Loss of Subcooling Additional Impacts

- Audit resulted in supplemental RAI response
  - Describe ambient heat loss flow paths
  - Updated FSAR, Section 5.4.5.2.1, to include maximum heat transfer rate specification for metallic reflective metal insulation

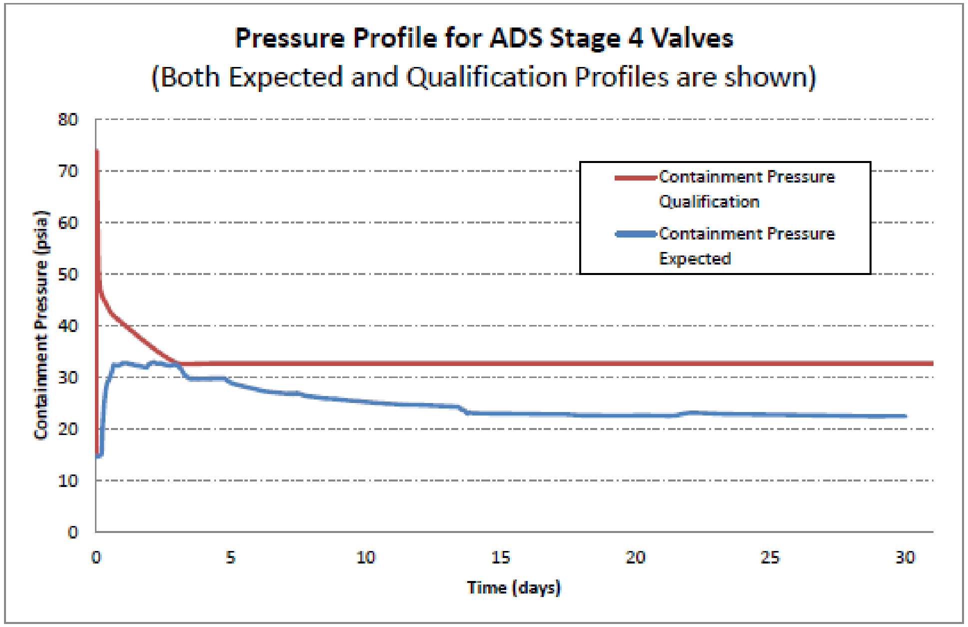
- Update criteria to establish open loop cooling
  - Power to IDS divisions B and C
  - Hot leg and CMT level
  - Core exit thermocouple temperature
  - RCS pressure

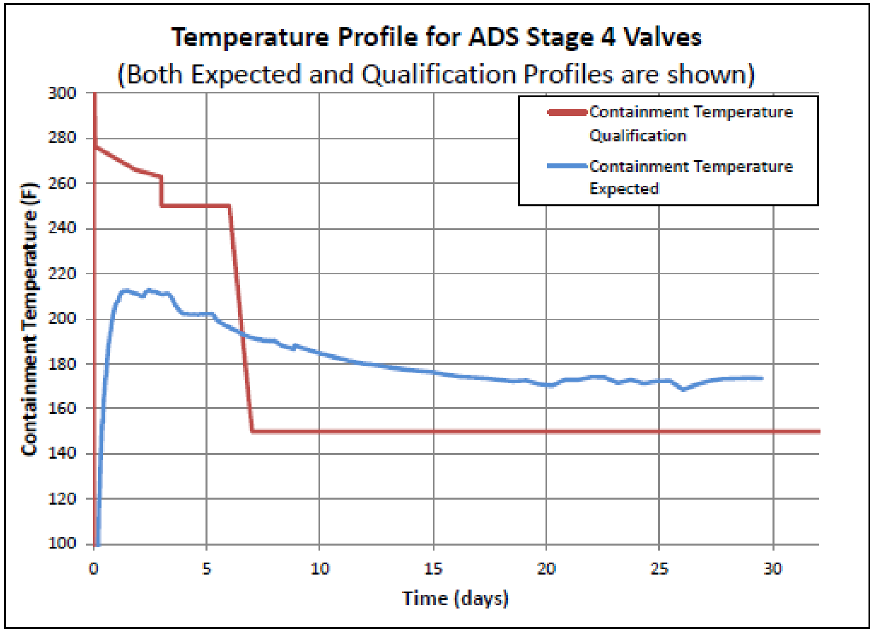
Transition to Open Loop Cooling

- NRC staff issues RAIs to address concerns over the equipment qualification of the ADS, IRWST injection, and containment recirculation valves
  - RAIs issued to Southern Nuclear Company (SNC) during staff review of SNC response to Order EA-12-049 (Mitigating Strategies)
  - Duke Energy endorsed the responses of SNC

- RAI response demonstrated:
  - Equipment qualification envelope for ADS, IRWST injection, and containment recirculation valves is bounding for a 30 day event event that utilizes the PRHR HX
  - IDS battery availability
  - Ability to establish open loop cooling in the absence of any power

Transition to Open Loop Cooling Equipment Qualification Envelope





Pressure

Temperature

Outline

Summary of staff review

- Licensing impact
- Review history
- Staff findings

Updates since last meeting

- Calculation revisions
- Confirmatory analysis
- Loss of subcooling

Resolution of interactions with ACRS

- Testing and Analysis
- Policy

Conclusions

Vendor inspection

Modeling of Heat Transfer in PRHR-HX

- Pool boiling in the LOFTRAN PRHR HX model was developed from the Westinghouse PRHR HX test program
  - Consisted of 3 vertical tubes
  - Test program included uncovery tests

Modeling of Heat Transfer in PRHR-HX (continued)

- Applicability of test data to C-shaped heat exchanger
  - Addressed in review of AP600
    - WEC performed blind calculations for PRHR-HX performance
    - NRC staff calculations consistent with WEC results

- Concern that high heat transfer rates could result in vapor blanketing of some portion of the heat exchanger
  - Addressed in review of AP600
  - Unlikely to occur
    - Not observed during testing performed at OSU/APEX, SPES-2, or ROSA/LSTF
    - If it does occur, it is limited to short length near inlet of tube bundle

Transition to RTNSS beyond 72 hours

- The PCCS is required to keep the core cooled for an indefinite period of time; the means to accomplish this vary depending on the time period:

  - 0-72 hours – Passive systems only; applicant has demonstrated reasonable assurance that PCCS will perform.
  - 72 hours-7 days – RTNSS ‘B’ systems available; for PCCS, this is limited to refill of the PCCWST for containment cooling. Under best estimate assumptions, PCCS continues to perform.
  - Past 7 days, offsite support is presumed available.
  - In all scenarios, the plant retains the ability to transfer to open loop cooling via ADS; in this case the core remains cooled until containment makeup is required (~30 days).

Safety Design Basis

- Subsection of Design Basis in AP1000 DCD
- Functional requirements identified in safety design basis are demonstrated through Chapter 15 safety analyses (with the exception of the cooldown requirement of reaching 420 ºF in 36 hours)
- Cooldown requirement of reaching 420 ºF in 36 hours in unchanged
    - FSAR update clarifies how this requirement is demonstrated

GDC 34 Application

- IRWST should be sized such that Chapter 15 acceptance criteria are satisfied for a minimum of 72 hours using the PRHR to meet GDC 34
  - Reactor subcriticality
  - Decay heat removal
  - Radioactivity containment (SAFDLs and pressure boundary)

- Events exceeding 72 hour duration not considered Condition II events

- Applicant identified limiting non-LOCA event (in terms of PRHR HX performance) and extended analysis out to 72 hours

Conclusions

- Updated calculation method does not impact staff's previous findings
  - Chapter 15 not impacted
  - Passive core cooling system is capable of cooling the RCS to 420 °F in 36 hours
- Consideration of ambient heat losses does not adversely impact Chapter 15 analyses
- Loss of subcooling expected to occur within 14 days
  - PRHR HX performance does not degrade
    - Analysis
    - Test data
- Transition to open loop cooling is retained as defense in depth

NRC Vendor Inspection of Condensate Return Issue

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- NRC Vendor Inspection – technically focused inspection of vendors implementing safety related quality activities
- NRC Inspection January 26 - 30, 2015, at WEC in Cranberry, PA; IR number 99900404/2015-202
- Issued Notice of Nonconformance (NON) against Appendix B Criterion XVI Corrective Action. WEC failed to promptly correct conditions adverse to quality and for significant conditions adverse to quality failed to take action to prevent repetition.
- WEC had previous opportunities and failed to generate an issue report for 2 years after initial identification by United Kingdom of the condensate return issue, improperly assessed the issue significance, and did not perform an extent-of-condition evaluation to identify other possible incorrect design assumptions.

Other NRC Inspection Findings

- Other examples of inadequate corrective actions were identified
  - two examples of oversight of safety-related suppliers
  - recurring issues with internal audits

- Issued Notice of Nonconformance (NON) against Appendix B, Criterion I, Organization. WEC failed to ensure that portions of the QA program were effectively executed, and verify that activities affecting safety-related functions have been correctly performed.
  - two examples of inadequate control of purchased material and services

- NRC received two letters from WEC (May 20 and July 16, 2015) in response to the Notice of Nonconformance and found the combined response to be acceptable.

- The NRC staff is tentatively proposing to perform an inspection of WEC's corrective action in FY2017.

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Presentation to the ACRS Subcommittee

Staff Review of AP1000 Design Changes and Departures in the Levy Nuclear Plant Combined License Application

Main Control Room Dose Departure

April 5, 2016

Acronyms and Definitions

- χ/Q – Atmospheric Dispersion Factor
- DBA – Design Basis Accident
- DEI-131- Dose Equivalent Iodine-131
- GDC – General Design Criterion
- MCNP – Monte Carlo N-Particle
- MCR – Main Control Room
- IRWST – In-containment Refueling Water Storage Tank
- ITAAC – Inspections, Tests, Analyses and Acceptance Criteria
- TEDE – Total Effective Dose Equivalent
- TS – Technical Specification
- VBS – Nuclear Island Nonradioactive Ventilation System
- VES – Main Control Room Emergency Habitability System

Outline

- Staff Review Team
- MCR Dose Departure Overview
- Licensing Impact
- MCR Direct Radiation
- Changes to DBA Dose Analyses
- Conclusion

Staff Review Team

- Michelle Hart
  - Accident Consequences (presenter)
- Ron LaVera
  - Radiation Protection (presenter)
- Eduardo Sastre
  - Materials and Chemical
- Nan Chien
  - Containment and Ventilation
- Don Habib
  - Project Management

MCR Dose Departure Overview

- DCD MCR dose analyses did not explicitly include direct radiation from VES filter and required updates

- Revised dose analysis affect all DBAs
  - Analyses are generic using design site parameter χ/Qs from DCD
    - Applicable to Levy because site characteristic χ/Qs are less than design site parameter χ/Qs
  - Added direct radiation dose contribution from MCR filters
  - Additional analysis changes made to increase analysis margin, update methods or incorporate updated detailed design information

- Potential to exceed GDC 19 dose criterion (5 rem TEDE)
  - Added VES filter shielding
  - Reduced TS allowable secondary coolant iodine activity concentration
  - Revised radiation monitor setpoint values

Licensing Impact

- Design changes include exemption request and site-specific departure from AP1000 DCD Rev. 19
  - LNP DEP 6.4-1
    - Revise DBA dose analyses
    - Add VES filter shielding and related ITAAC
    - Reduce TS allowable secondary coolant iodine activity concentration
    - Revise radiation monitor setpoints
    - Change the VES actuation signal name from “high-high” to “High-2”

- Levy FSAR/DCD chapter and section changes
  - DCD Tier 1 Sections 2.2.5 and 2.7.1, Tables 2.2.5-1 and 2.2.5-5
  - FSAR 1, 3, 6, 7, 9, 11, 12, 14 and 15
  - TS 3.7.4, TS Bases 3.4.10, 3.7.4 and 3.7.6

MCR Direct Radiation

- Areas examined by the staff
  - Dose from VES filter
  - Shielding provided for VES filter
  - Shielding Analysis methods used by applicant
- Review methods used by the staff
  - Scoping calculations – MCNP, MicroShield, Excel, Origen-ARP
  - Audit of applicant MCR envelope design packages
  - Audit of applicant MCNP shielding input/output files
    - VES filter
    - VBS filter
    - Plant and MCR shield walls
- Results – The amount of margin between the calculated MCR total dose ensures compliance with GDC 19 for use of Safety Related VES system

Changes to DBA Dose Analyses

- Changes that affect only MCR dose
  - Increase in assumed VES filter efficiency for organic iodine
  - MCR volume and ventilation system flow rates
  - VES initiation time based on revised radiation monitor setpoints
- Changes that affect both MCR dose and offsite dose
  - Revised modeling of iodine re-evolution from IRWST
  - Increased value for containment elemental iodine deposition removal coefficient
  - Use of updated approved method to estimate fuel damage for rod ejection accident
  - Revised steam release rates for main steam line break accident
    - earlier steam generator dryout scenario bounding for MCR dose
  - Secondary coolant iodine activity concentration reduced to 0.01 µCi/gm DEI-131
  - Other changes to analysis assumptions based on updated detailed design information

Changes to DBA Dose Analyses (cont.)

- Review methods used by the staff
  - Audit of applicant MCR envelope design packages
  - Audit of applicant DBA revised dose analysis packages
  - Comparison of proposed revised methods to NRC guidance
- Results
  - Proposed changes are acceptable because they either use methods that were previously found acceptable in review of the DCD or use methods that are in conformance with NRC guidance, use updated detailed design information, and/or reflect the proposed site-specific changes to the design.
  - Revised DBA dose analyses show that the estimated offsite and MCR dose meet the applicable dose criteria.

Conclusion

- Staff has reasonable assurance that the proposed MCR dose analysis departure from the AP1000 certification rule at the Levy Units 1 and 2 site meets the following requirements:
  - 10 CFR 52.79(a)(1) dose guidelines and the dose acceptance criteria in SRP 15.0.3 with respect to the offsite radiological consequences of DBAs
  - GDC 19 control room habitability dose criterion for operation of the VES under High-2 radiological conditions for all DBAs

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Protecting People and the Environment

Presentation to the ACRS Subcommittee

Staff Review of
AP1000 Design Changes and Departures in the Levy Nuclear Plant Combined License Application

Main Control Room Habitability (Heatup)

April 5, 2016

Acronyms

- ADS – Automatic Depressurization System
- IRWST – In Containment Refueling Water Storage Tank
- MCR – Main Control Room
- NWS – National Weather Service
- PCCS – Passive Containment Cooling System
- PCCWST – Passive Containment Cooling Water Storage Tank
- PCG – Polar Crane Girder
- PRHR HX – Passive Residual Heat Removal Heat Exchanger
- PXS – Passive Core Cooling System
- VES – Main Control Room Emergency Habitability System
- WBGT – Wet Bulb Globe Temperature
- WPIS – Wall Panel Information System
- Tdb – Dry Bulb Temperature
- Twb – Wet Bulb Temperature

Outline

- Staff Review Team
- MCR Temperature and Humidity
- First 72 hours
- Post-72 hours
- Impact on Human Performance
- Conclusion

Staff Review Team

- Boyce Travis
  - Containment and Ventilation (presenter)
- Paul Pieringer
  - Human Factors Engineering (presenter)

- James Strnisha
  - Mechanical Engineering
- Jack Zhao
  - Instrumentation and Controls
- Hien Le
  - Balance of Plant and Technical Specifications
- Malcolm Patterson
  - Probabilistic Risk Assessment
- Nan Chien
  - Containment and Ventilation
- Kevin Quinlan
  - Meteorology and Hydrology Branch
- Don Habib
  - Project Management

MCR Temperature and Humidity

- Two periods of interest:
  - 0-72 hours (VES in operation)
  - 3-7 days (ancillary fans in operation)

- New heat load (result of revisions to heat loads plus addition of load shed) in GOTHIC analysis changes temperature profile

- Due to acceptance criteria, both dry bulb and wet bulb temperature (humidity) are important parameters
  - Human Performance: WBGT < 90 F
  - Equipment Qualification:
    - 0-72 hours - < 95 F and 60 % Relative Humidity
    - 3-7 days - < 110 F and 35 % Relative Humidity

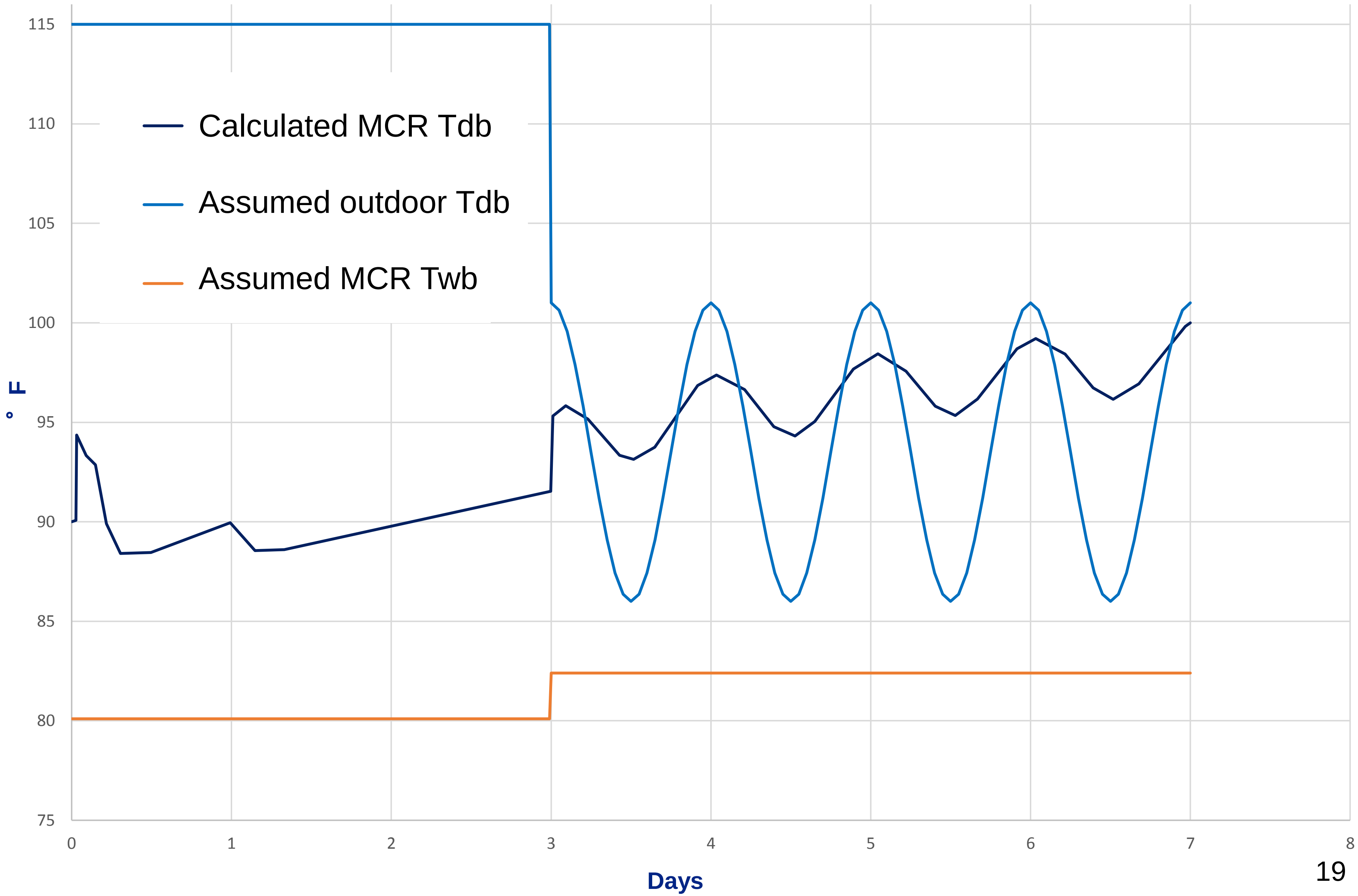
First 72 hours

- Staff reviewed GOTHIC analysis and found it conservatively captured dry bulb MCR temperature with the new heat load and load shedding (profile on slide 19)
- Applicant assumed a constant ambient dry bulb temp. of 115 F
- Humidity calculated separately by applicant
  - Value asymptotically approaches steady state, due to dry air input from VES bottles and subsequent leakage from the MCR
  - Applicant used initial conditions of 75 F, 60% RH (the nominally limiting values) to determine that assumed value was conservative
  - While staff agrees that those values are the highest expected in the MCR, staff performed a confirmatory calculation using 75 F, 100% RH (TS limited value) and found that maximum T_{wb} was ~79 F, less than the 80.1 F assumed in the analysis
- MCR substantially lower than 90 WBGT during first 72 hours

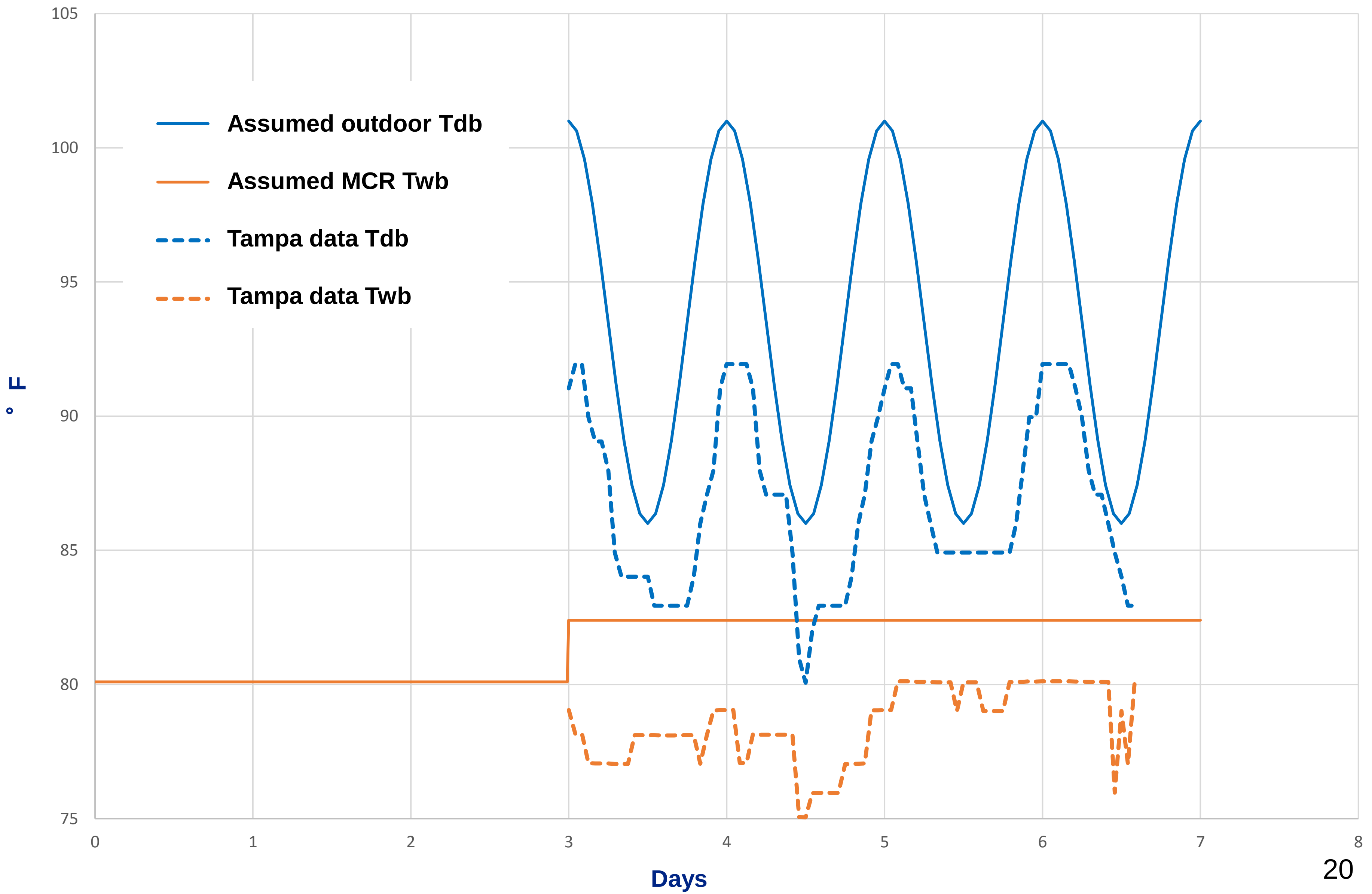
Post-72 hours

- After 72 hours, ancillary fans are placed in service to ventilate 1500+ cfm of outside air through the MCR
  - This results in outside air being a primary driver of MCR conditions
- Applicant assumed diurnal outside air temperature curve with 101 F peak and 15 degree day/night difference, with a constant wet bulb temperature of 82.4 F
- Staff compared these values to NWS station data near the site, and found them acceptably bounding
- Staff concluded the analysis demonstrated reasonable assurance that MCR would remain below 90 WBGT for 7 days, even under the worst case outdoor conditions (and substantially lower under any cooler conditions)

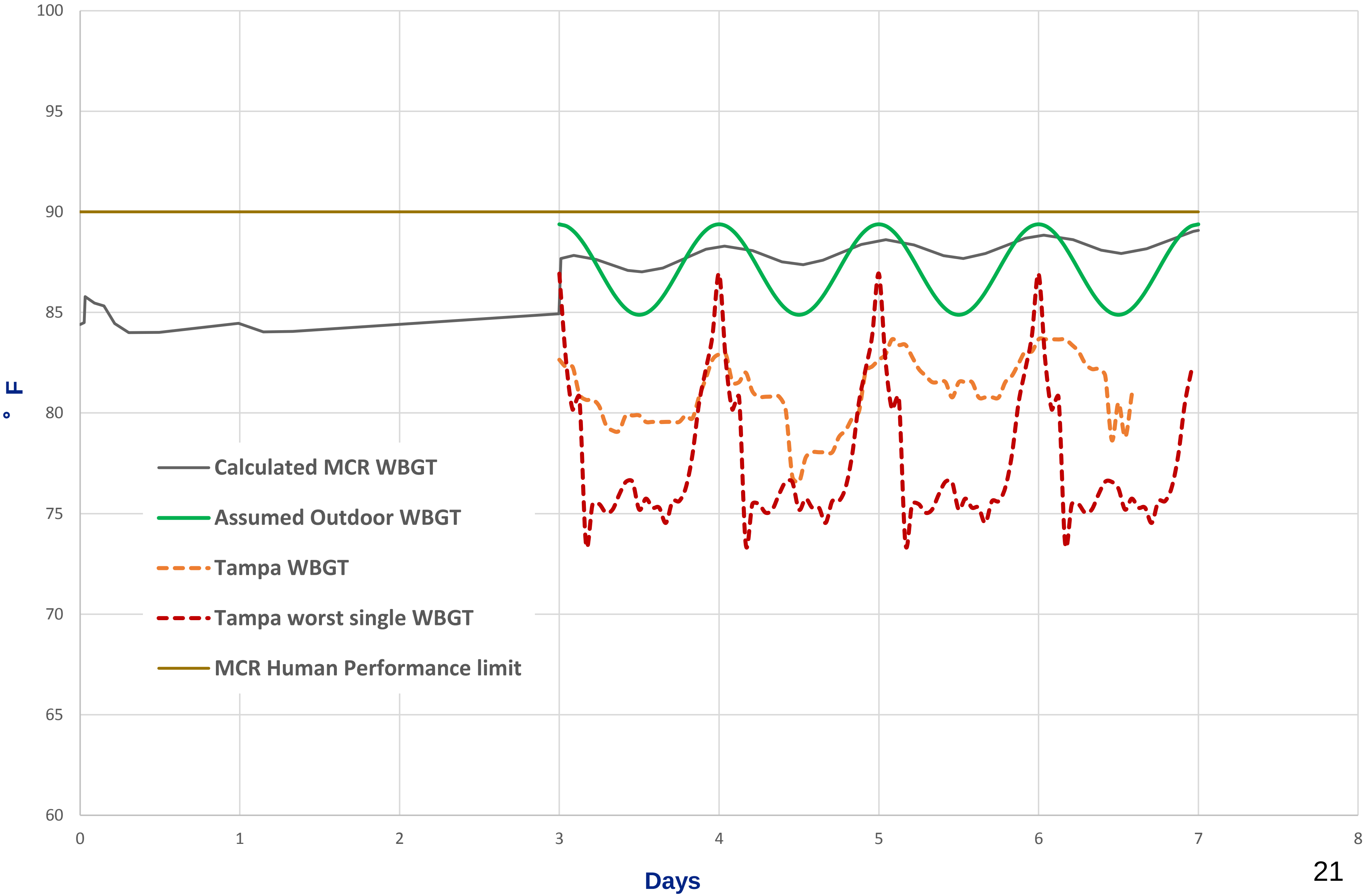
Temperature in MCR



Wet/Dry Bulb Temperatures



Wet Bulb Globe Temperature



Moisture in VES Bottles

- The certified design lacked humidity control of the VES air

- If VES moisture content was high enough:
  - Freezing at the VES regulator was possible due to the Joule-Thomson effect
  - The associated increase in MCR humidity values from input moisture could have the potential to challenge the MCR human performance acceptance criteria.

- RAI response proposed changes to FSAR to state the air in the VES bottles will be supplied as ANSI/CGA-7.1 Quality Level E with a pressure dew point temperature not to exceed 40 F at 3400 psig.

Impact on Human Performance

Stage 2 load shed of the Wide Panel Information System (WPIS)

- WPIS credited in the AP1000 Design Certification as part of state-of-the-art control room supporting teamwork, situational awareness, and command and control

Impact on Human Performance

1. What events must occur to result in VES actuation with off site power available?
2. Assuming these events occur, is there a sequence that would result in the plant remaining at power and if so for how long?
3. What indications remain available?

Impact on Human Performance

1. What events must occur to result in VES actuation with off site power available?

   - Multiple independent failures and/or beyond design basis events

2. Assuming these events occur, is there a sequence that would result in the plant remaining at power and if so for how long?

   - Yes, 26 hours before Tech Specs required a shutdown

Impact on Human Performance

3. What indications remain available?

    - Shift Manager Office Console
    - Senior Reactor Operator Console
    - Reactor Operator Consoles (excluding business LAN)

Conclusion

- The staff finds that MCR remains within temperature and humidity limits for human performance and equipment qualification
  - Substantial margin while VES in operation for first 72 hours
  - Remains within limits post-72 hours

- The staff finds the change of acceptance criteria for control room habitability from the effective temperature of 85 F to a WBGT of less than 90 F acceptable. The new limit, based on NUREG-0700 (the established NRC-approved standard for human factors guidance) maintains an unlimited stay time in the control room.

- The staff finds that, given the low probability of events resulting in WPIS load shed and the availability of alternate indications, the WPIS load shed does not undermine the acceptability of the WPIS system

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Presentation to the ACRS Subcommittee

Staff Review of AP1000 Design Changes and Departures in the Levy Nuclear Plant Combined License Application

Combustible Gas Control in Containment (Hydrogen Vent ITAAC)

5 April 2016

Outline

- Staff Review Team
- Licensing impact
- Regulatory Basis
- Review
- Results
- Conclusions
- Acronyms

Staff Review Team

- Anne-Marie Grady
  - Containment and Ventilation (presenter)
- Pravin Patel
  - Structural Engineering (presenter)
- Malcolm Patterson
  - Probabilistic Risk Assessment
- Don Habib
  - Project Management

Licensing Impact

- Purpose is to establish consistency between the AP1000 certified design and the Levy plant
- Includes exemption request and two departure requests from AP1000 DCD Revision 19
- LNP DEP 6.2-1 proposes to change the acceptance criteria to a specific ITAAC in Tier 1 Table 2.3.9-3, Item 3iii to state:

  > "The equipment access opening and CMT-A opening constitute at least 98% of vent paths within Room 11206 that vent to Room 11300. The minimum distance between the equipment access opening and containment shell is at least 24.3 feet. The minimum distance between the CMT-A opening and the containment shell is at least 9.4 feet. …"

Licensing Impact, cont'd

- Departure 6.2-1 requests

- Levy FSAR Tier 2, chapter 6.2.4.5.1, Preoperational Inspection and Testing, Hydrogen Ignition Subsystem, be revised to reflect the change

- Levy FSAR Tier 2, chapter 19.41.7, "Diffusion Flame Analysis", be revised to reflect the change

Regulatory basis

SECY-93-087 I.J Containment Performance, states that the containment performance during a severe accident challenge should:

- maintain its role as a reliable, leak-tight barrier by ensuring that containment stresses do not exceed ASME Service Level C limits for a minimum period of 24 hours following the onset of core damage, and

following this 24-hour period the containment should

- continue to provide a barrier against the uncontrolled release of fission products.

Technical Evaluation

- The goal is to keep postulated hydrogen diffusion flame sources away from the containment pressure boundary, to prevent conditions leading to potential failure of the containment shell, hatches, and penetrations.

- The purpose of the ITAAC is to confirm this distance

- Applicant review of existing assessment showed that a burning hydrogen plume from the passive core cooling system (PXS)-A compartment (Room 11206) to the core makeup tank (CMT)-A (Room 11300) could potentially challenge containment allowable limits.

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Technical Evaluation

- The hydrogen venting scenario from the PXS-A room is for a beyond-design-basis event involving hydrogen generation due to fuel cladding oxidation.
- The scenario pertains to a single initiating event, a direct vessel injection (DVI) large-line break which spills into the PXS-A compartment below the CMT room.
- The break must be large enough to defeat injection through the DVI line for the accident to progress to core damage. The PSX-B line must also fail to inject.
- Multiple failures of the ADS-4 valves must occur for the hydrogen generated in the core to reach the DVI line break and be released into the PXS-A compartment.
- The cut set frequency for this scenario, from the AP1000 probabilistic risk assessment is 6.4E-09/reactor-year.

Technical Evaluation

- Applicant performed a CFD sensitivity analysis to locate hot spots and any flow split variation effects from the PXS-A room vents.
- Applicant performed a one-dimensional (1D) heat transfer analysis to calculate temperature distributions on the containment pressure boundary in the CMT-A area near the lower equipment hatch.
- Radiation and convection heat transfer were modeled
- Maximum temperatures on the containment shell, equipment hatch cover, and the hatch barrel were calculated.
- These temperatures were averaged for suitable input to the program used for the structural analysis.

Technical Evaluation

	Temperature (° F (° C))	Peak Average Temperature (° F (° C))	Peak Average Temperature (° F (° C))
Component	Hot Spot Allowables	Zone 1 Radiation and Convection	Zone 2 Radiation Only
Containment Shell	607 (319)	442 (228)	411 (210)
Insert Plate/Barrel	390** (199)	308 (153)	293 (145)
Hatch Cover	780 (416)	577 (303)	530 (277)

Allowable maximum temperature limit from ASME Code Service Level C for SA 738 Grade B.

** Allowable maximum temperature limit for insert plate/barrel corresponds to acceptance criterion for ethylene propylene diene monomer (EPDM) rubber

Structural Evaluation of CV

- Staff focused review of survivability of the CV including equipment hatch to confirm that the containment integrity is not challenged due to hydrogen diffusion flame migrating from the PXS-A compartment.
- Particular emphasis on:
  - Temperature distribution on CV and equipment hatch considering hot spot. The hot spot area is a local area where the burning plume could affect the CV pressure boundary.
  - Peak average wall temperature on the hot spot is 780 ºF
  - Temperature limit of 390 ºF for the equipment hatch seal is based on EPDM rubber manufacturer allowable.
  - The CV and the hatch stresses are within ASME NE-3000 Service Level C. The metal resultant stress of 15.25 ksi from ANSYS analysis vs ASME allowable of 63.6 ksi at 800 F.
  - Metal creep is not significant factor for short duration
- Staff concluded that the applicant analysis meets the ASME requirements and the containment integrity is not challenged.

Conclusions

- Staff concludes that the methodology and assumptions in the analysis for determining the temperature source terms from the hydrogen burns are appropriately conservative, and the results are acceptable to be used as input to the structural analysis
- Based on the staff's evaluation of containment survivability, the staff finds that containment integrity is not challenged due to diffusion flame hydrogen burn from the CMT-A room in the containment.

Acronyms

- ADS – Automatic Depressurization System
- CFD – Computational Fluid Dynamics
- CMT – Core Makeup Tank
- CVS – Chemical and Volume Control System
- CV – Containment Vessel
- DVI – Direct Vessel Injection
- IRWST – In Containment Refueling Water Storage Tank
- ITAAC – Inspections, Tests, Analyses and Acceptance Criteria
- PXS – Passive Core Cooling System
- VLS – Containment Hydrogen Control in Containment System

Presentation to the ACRS Subcommittee

Staff Review of
AP1000 Design Changes and Departures in the Levy Nuclear Plant Combined License Application

Source Range Flux Doubling Logic for Boron Dilution Operating Bypass (IEEE 603-1991)

April 5, 2016

Abbreviations

- CVS – chemical and volume control
- DWS – demineralized water system
- PMS – protection and safety monitoring system
- RCS – reactor coolant system

Outline

- Staff Review Team
- Background Information
- Regulatory Requirements
- Existing Design
- Revised Design
- Conclusion

Staff Review Team

Jack Zhao

- Instrumentation and Controls (presenter)

Chris Van Wert

- Reactor Systems

Hien Le

- Balance of Plant and Technical Specifications

Malcolm Patterson and Marie Pohida

- Probabilistic Risk Assessment

Don Habib

- Project Management

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Background Info

- Issue identified to staff in initial submittal – 9/1/15
- RAIs:
  - ➢ Issued 11/25/15 and responded to 12/23/15
  - ➢ Topics:
    - o Revisions to technical specifications
    - o Clarification of logic changes

Regulatory Requirements

- IEEE Std. 603-1991, “Criteria for Safety Systems for Nuclear Power Generating Stations” Is incorporated by reference in 10 CFR Part 50.55a(h)

- Clause 6.6 includes the following requirements for operating bypasses:

  - Whenever applicable permissive conditions are not met, a safety system shall automatically prevent activation of an operating bypass of a safety function

    or

  - Initiate the appropriate safety function(s).

Current Design

- Operators can block the source range flux doubling logic input to the boron dilution block at any time.

- No permissive conditions were implemented in the PMS to permit bypassing of source range flux doubling logic for boron dilution block during startup.

Revised Design

Changes proposed to ensure regulatory compliance:

- Add a new permissive, P-8, to permit bypassing the flux doubling logic safety function.
- P-8 Is set to 551^{o}F, the minimum reactor coolant system (RCS) temperature for criticality.
- Add logic in PMS to force chemical and volume control (CVS) demi. water system (DWS) isolation valves **closed** if the flux doubling logic is bypassed while RCS temp. < P-8.
- Add a reset of flux doubling logic when RCS temperature falls below P-8.
- Corresponding changes made in technical specifications and Tier 2.

Conclusion

Based on the evaluation, the staff concludes that the changes to the PMS design for bypassing the source range neutron flux doubling logic input to the boron dilution block comply with Clause 6.6 of IEEE 603-1991, "Operating Bypasses."