MR. DAIBER: That is correct. Again, the methodology, though, is still in compliance with Appendix K --

MEMBER BONACA: I understand.

MR. DAIBER: -- considerations.

MEMBER SIEBER It was --

MEMBER KRESS: What were these values for the ANO2 without the uprate?

MR. DAIBER: The peak clad temperature for large break LOCA was 2,029.

MEMBER KRESS: Okay.

MR. DAIBER: For the large break. And for small break LOCA, it was 1,905. I don't have the other ones readily available.

MEMBER KRESS: Okay.

MEMBER SHACK: And that's with the same analysis methodology.

MR. DAIBER: The same break LOCA, yes. The large break, we switched.

MEMBER SIEBER It was my understanding that the large break LOCA evaluation model used FLECHT data, or reflood heat transfer coefficients. Is that correct? And that was one of the factors that gives you additional margin?

MR. DAIBER: I'll let Joe Cleary from

Westinghouse address that. He can more appropriately answer that question.

MR. CLEARY: Yes. The large break evaluation model does use FLECHT-based reflood heat transfer coefficients, and one of the improvements we made going from the 1985 EM to the 1999 EM was to improve the procedure for applying the FLECHT correlation.

MEMBER SIEBER Could you tell me about how much margin you think you gained on a Plant like this in degrees between old and new --

MR. CLEARY: For that change, I believe it was a little bit less than 100 degrees on that particular one.

MEMBER SIEBER Okay.

MR. CLEARY: The sample calculations we showed in the topical gave a range of 64 to 72 degrees --

MEMBER SIEBER Okay.

MR. CLEARY: -- for a couple of calculations.

MEMBER SIEBER Okay. But 100 is a good number?

MR. CLEARY: I would go a little bit less than 100. Overall, the change from the '85 EM to the

'99 EM resulted in a change of 150 degrees net.

MEMBER SIEBER Okay. Thank you.

MR. CLEARY: Approximate.

MR. DAIBER: So we have performed the LOCA analysis and verified acceptable results under operating conditions.

With that, I'm going to jump back up to Agenda Item Number 4, which are the review issues, and with this I'm going to switch things on around here a little bit again too. I'm going to start out with ATWS considerations.

ANO2 is a CE-designed Plant, and so our approach to ATWS is different than that that the boilers and some of the Westinghouse plants have considered. Boilers and some of the Westinghouse plants do credit operator action and perform analyses to ensure compliance with the ATWS considerations. ANO2, being a CE Plant, for our compliance with 10 CFR 50.62 ATWS requirements, we installed a diverse and redundant SCRAM system. We also installed a diverse emergency feedwater actuation system and took credit for a diverse Turbine Trip system at the Plant.

For power uprate considerations, we verified that these systems and their set points and response times associated with these systems would

still remain valid under uprated conditions to ensure compliance with the ATWS considerations.

I'm going to move on to the impact of containment response. We did, obviously, redo the containment analysis. When we redid that analysis, we looked at both the steam line break and the LOCA considerations. The mass and energy that was generated for that peak building pressure consideration, they were generated using Westinghouse CE combustion engineering, Westinghouse methodologies to generate mass and energy release. That mass and energy release data is input into the BECHTEL COPATTA code, which is our containment peak building pressure analysis code, to get the new peak building pressure considerations. When we did all this, we did it as part of the RSG project, and we did it to account and cover power uprated conditions, and it's all been approved as part of License Amendment 225 already.

For the LOCA, we did look at cold leg, hot leg -- cold leg discharge, cold leg suction, hot leg break considerations. We did look at various single failures to come up with the limiting LOCA peak building pressure considerations, and the loss of an EDG was a limiting single failure. For the steam line break, we looked at a range of power levels and a

range of single failures associated with this.

And as I mentioned before, we installed integral flow restricting nozzles in the CSAS actuation signal to isolate main steam and main feed, such as the hot zero power steam line break is now the most limiting break with the single failure of a spray. The new peak building pressures associated with the LOCA was 57.6 psig, and with the hot zero power steam line break, it's 57.4 psig.

As part of compliance with Appendix K methodologies for peak clad temperature considerations, we also do a minimum containment pressure analysis, and that peak pressure was 27 psig, but that's for Appendix K compliance considerations, just to show the relative margin between peak building pressure and minimum building pressure for LOCA considerations.

With that, I'd like to turn it over to Dale James for alloy 600 considerations.

MR. JAMES: Thank you, Bryan. Good afternoon. My name is Dale James. I'm the Manager of Engineering Programs and Components at Arkansas Nuclear One. I will be discussing the impact of the power uprate on our alloy 600 nozzles in the RCS and on the secondary components due to the flow

accelerated corrosion.

As Bryan mentioned, the power uprate was made possible by the replacement of the ANO2 original steam generators with new generators made with alloy 690 tubing, but also with a heat transfer area of approximately 25 percent greater than our original steam generators.

By increasing the heat transfer area by this magnitude, we were able to accommodate the power uprate with only a marginal increase of the T hot to 609 degrees. Historically, our T hot has run between 600 and 607. Under the power uprated condition, T cold will be approximately 551, which is actually a reduction in the T cold from our original cycles of operation by about two degrees. The pressurizer conditions will remain unchanged. Temperatures and pressures there will be consistent with the power uprated conditions.

Therefore, for the uprate, we evaluated the effects of the increase in temperature on the reactor vessel head nozzles and the hot link nozzles. The increase in T hot for the reactor vessel head nozzle has been evaluated using the same methodology as the industry has used to evaluate the conditions identified in NRC Bulletin 2001-01. That was dealing

with the Oconee 3 circumferential cracking issues.

The methodology is founded -- or is based upon EPRI Material Reliability Program documents 44 and 48. And this process ranks components based upon their potential for a primary water stress corrosion and cracking of the reactor vessel head nozzles. And that ranking is based upon a plant's operating time, adjusted for the difference in reactor vessel head operating temperature using an activation energy model.

Considering the increase in T hot at ANO2, the ranking time was decreased for the power uprated condition from 17.1 EFPY to 14.2 EFPY. With this reduction, ANO2 remains in what I've characterized as a moderate category. That is a range of five to 30 EFPY that the bulletin established for reaching a condition similar to that at Oconee 3.

For this category of plant, the bulletin recommended that the licensee perform an effective visual examination of the reactor vessel head nozzles during the upcoming refueling outage. Due to constraints that we have with respect to our insulation design on ANO2, we are unable to perform a 100 percent visual examination of the reactor vessel head. Therefore, during our upcoming refueling

outage, we will be performing a 100 percent UT examination from below the head.

With respect to the hot leg nozzles --

MEMBER SHACK: When is that outage, this spring?

MR. JAMES: This spring. It begins this April.

For the hot leg nozzles, we will be continuing to perform a 100 percent bare metal examination at each of our refueling outages to detect any signs of leakage. To date, we have replaced nine of the 19 hot leg nozzles, and those replacements are performed with alloy 690 material. All the nozzles below the water line in midloop have been replaced to date. As I mentioned, we will continue to perform those examinations in the future to detect any leakages of any additional nozzles.

MEMBER SHACK: I asked this question before, and I can't remember the answer. Your surge line, is that stainless, so do you have 182 butters anywhere?

MR. JAMES: Yes. Because they're all shop-welded safe ends, then connected to the stainless nozzles.

MEMBER SHACK: But that's just for the

pressurizer.

MR. JAMES: Yes. Now, we have other stainless components. Our reactor coolant pump casings are stainless also in the cold legs. Those also have shop-welded safe ends on them and butters at the shop. Okay?

With respect to FAC, the impact of power uprate on secondary components were evaluated utilizing the EPRI CHECKWORKS Program. A parametric study was performed assuming a maximum steaming rate under the power uprated conditions. The Check rate model predicted minimal impact on FAC wear rates. This prediction is consistent with those that other utilities have evaluated under power uprate conditions and is also consistent with measured values following uprated conditions.

Following uprate, we will continue to monitor those areas that are most susceptible as a result of the power uprate condition, and if we see any deviations from what the model predicted, we'll factor that back into our modeling for any future repair and replacement decisions.

MEMBER SIEBER Could you give me an estimate, from a percentage standpoint, about how much increase CHECKWORKS predicted for FAC?

MR. JAMES: Yes. What we did was looked at some of the more susceptible components as were identified as a result of the power uprated conditions. What we saw there is probably an average increase in wear rate of about five mils per year. That's added on to what we would consider a relatively low wear rate right now. So we were not anticipating any major modifications or any major changes in our wear rate.

MEMBER SIEBER Okay. Thank you.

MEMBER SHACK: Have you done chrome-olly replacements?

MR. JAMES: Yes. All of our replacement is done with two and a quarter chrome-olly, which essentially eliminates FAC wear.

MEMBER SHACK: But how much of your secondary piping now is chrome-olly or you just do it as you go?

MR. JAMES: Well, we do it as we go, but we take a very proactive approach to that. We're replacing probably on the order $300,000 to $400,000 worth of piping each refueling outage. So we're not waiting until a system wears to a point where we're on threat of losing a component.

Okay. In conclusion, our evaluation shows

power uprate will only have minimal impact on both our alloy 600 nozzles and our FAC wear rate, although we will continue to evaluate and monitor those systems to ensure our predictions are consistent.

I'm going to turn it over now to Rich Swanson in our operation organization.

MR. SWANSON: Hi. I'm Rich Swanson. I'm a senior reactor operator on Unit 2. I'm the ops lead for power uprate, and I was also a member of the Steam Generator Replacement Team.

Training has already started on our new plant. Simulated changes have been made, and we have two training cycles that are concentrating on power uprate. Each crew will be evaluated on an uprated plant prior to outage. And I'd like to point out, the changes we're doing for power uprate have much less impact than those we did last cycle for steam generator replacement.

Changes to controls and displays have been minimal or none. We've made no physical modifications to control stations due to power uprate, and there's no change in the format or the Safety Parameter Display System.

We have made about 75 procedure changes for power uprate, and that includes emergency abnormal

and normal operating procedures. There's been no change to the type and scope of procedure, and we haven't had to write any new procedures for power uprate. As far as emergency operating procedures, once again, there's no change to type and nature of actions, and we have added no new actions.

Operations is heavily involved in the development and implementation of Power Ascension Testing. We have test teams designated to perform all the testing coming up out of outage. They'll be working with the test group. And these are experienced teams. The operations leads on these test teams are also involved in the steam generator replacement testing.

This slide shows our power ascension profile for coming up out of our next outage. The first four points are standard for coming up out of any outage. You have turbine over speed testing and three points for physics testing. And we'll stop at 90 percent power, which is approximately 98 percent of our current power level. And they'll be performing walkdowns, vibration checks, control system checks, parameter verifications. And we'll make sure everything is where we predicted it to be before we increase power.

You see those hold points? About 24 to 48 hours at each hold point. From there we'll go up in 2.5 percent increments and repeat all the testing.

I'd like to turn it over to Joe Kowalewski, who will talk more about our Start-Up Test Program.

MR. KOWALEWSKI: Joe Kowalewski. I'm the director of engineering, and going to review the Start-Up Testing Program that we've got outlined.

Our Start-Up Test Program is in compliance with Test Spec 6.9.1, which requires that we review against our original start-up testing program as documented in the Safety Analysis Report. Original testing for the plant was in compliance with Reg Guide 1.6.8.

We've gone through the Safety Analysis Report, reviewed approximately 150 tests specified in that report. We've also looked at the scope of all the modifications that were done both for the replacement steam generator as well as the power uprate.

We've used industry experience to look at our Start-Up Test Program. We looked at recent CE System 80 plants that have started up and reviewed their test programs. We reviewed the start-up test

programs associated with other steam generator and replacements in power uprates. And then after we completed the development of our test program, had an assessment done with industry expertise, both combustion engineering in Westinghouse and start-up leads from other plants that validated our test program.

We have done extensive start-up testing for the steam generator replacement already. Much of that is credited for the power uprate. That includes post-modification testing associated with each of the modifications that was performed in the plant; performance of the components as well as the control systems; the containment testing for the uprate of containment, which was the Structural Integrity Test as well as the Code Test there. And steam generator performance testing-- both components effects on the plant as well as performance of the generator itself.

Additional testing we intend to do, we will as part of our shut-down into 2R15 do a 25 percent load rejection to further benchmark our integrated control system response. We have tested each of the control systems, and this will give us additional data to see if there's any final adjustments we need to make before we go up further in

power.

And we will be doing the routine pre-criticality low power physics and power range testing to validate the core design. So we'll do the power range testing both at our 90 percent, and then again when we reach 100 percent in our operating conditions.

As Rich talked about, we have a overall work plan for control of the power extension coming out of the outage. We'll stop at 90 percent, take extensive data, baseline the plant there, and then go in 2.5 percent increment above that. As we take the data both on the primary and secondary side, we'll be looking and comparing it to our heat balance as well as all of our design predictions. And it will be reviewed by a test working group made up of senior ANO plant management, including the operations manager, systems engineering manager, design manager, and our on-site Review Committee chair.

We'll be verifying our heat balance at each of those points and collecting a wide variety of key parameters, both on the primary and secondary side. We'll be doing biological shield surveys at each point and piping vibration testing both inside and outside of containment. And inside containment

we'll be using hand-held instrumentation on the feed water and steam lines.

Once we get up at our operation condition, we will be doing a moisture carryover test as well as performance testing of the steam generator. A question that came up in the subcommittee meeting was relative to steam quality and effect on the turbine. Right now, at our current conditions, in the replacement steam generator we're seeing .02 percent on one steam generator and .013 on the other, with an acceptance criteria of .1. That's compared to a steam quality of .2 percent -- approximately .2 percent -- for the old steam generator. So the steam quality is actually an improvement over what we had before. And we don't expect any negative effects ont the turbine.

MEMBER SIEBER Do you offhand know what the turbine rating is for inlet quality?

MR. KOWALEWSKI: The rating.

MEMBER SIEBER A lot of times they're something like 1 percent. And so, below 1 percent, that sort of tells you how much margin you have.

Do you know what it is?

MR. KOWALEWSKI: I don't know offhand what the turbine rating is.

MEMBER SIEBER Who's the turbine manufacturer?

MR. KOWALEWSKI: It's a GE turbine.

MEMBER SIEBER Okay.

MR. KOWALEWSKI: Vince, do you know that

MR. BOND: I've heard the term 1 percent.

I'm Vince Bond, start-up testing group supervisor. I've heard 1 percent before from various design people. I don't know that for a fact myself, but 1 percent is the term that I've heard.

MEMBER SIEBER I guess it's not very important. But it looks like you have a lot of margin.

MR. KOWALEWSKI: Okay. The acceptance criteria for the test is 1 percent.

MEMBER SIEBER Thank you.

MR. KOWALEWSKI: .1 percent. I'm sorry.

The plant will be verified form --

MR. WILSON: Excuse me. I'm Roger Wilson with Entergy.

On moisture carryover, the design of the RSG gave us a lot more volume for feedwater control. The original steam generators had a conical section that went into a cylindrical sectional. Now it's strictly in a conical section. So we've done a lot of

looking at high-level trip, and we have a lot more margin for that than we had with the original steam generators. And, of course, the turbines being more efficient, they're designed for going deeper into the two-phase dome. And they're probably designed for that.

MR. KOWALEWSKI: Our test program will verify that we're performing in accordance with the design parameters, and we'll document that in our test report within 90 days of the plant start-up.

Now I'd like to return it to Bryan Daiber, who's going to talk about the impact of power uprate on point risk.

MR. DAIBER: I'm Bryan Daiber, again.

For the power uprate considerations, not only did we look at the safety analysis considerations, but we also looked at the potential risk impacts associated with power uprate. And we did this effectively in several forms. We did quantify the effects of power uprate on the core damage frequency and the large early release frequency considerations.

We also in more of a qualitative fashion, we addressed the effects of power uprate on the external events-- seismic, fire vulnerabilities,

tornadoes, winds, failures, transportation accidents at nearby facilities and awful long shut-down risk considerations.

For looking at the core damage frequency, the Level 1 considerations and the impacts of power uprate on those, we reviewed the initiating event frequencies, we reviewed the success criteria, component failure rates, system fault trees, and operator responses associated with the Level 1 CDF considerations.

We reviewed all of these and implemented the effects of power uprate in all of these areas. The area that was most impacted by power uprate were the operator responses.

For the operator response considerations, we did review the operator responses credited in the Level 1, core damage frequency considerations. To quantify the impacts of power uprate on those we ran a CENTS analysis for various sequences.

The CENTS code is a Westinghouse code used to do the Chapter 15, Thermal Hydraulic Analysis. When doing that analyses, we ran that code to determine the time to core uncovery. And we did a comparable run both at current power rating and at uprated conditions to determine the different times

associated with each. We then took those times, and we put them into the human reliability analysis to come up with a human error rate.

We took those human error rates along with all the other changes that were necessary with respect to the success criteria, initiating band frequencies, and the fault tree considerations. We put those into a power uprated model. We quantified both the pre-power uprate model and quantified the post-power uprate mode, came up with a delta CDF. The delta CDF was $2.7E^{-6}$, which was essentially a 16 percent increase. This falls within Region 2 or small change as defined by Reg Guide 1.174.

In a similar manner --

MEMBER KRESS: Is that the same number, that pre, that you had in your IPE?

MR. DAIBER: No, it is not. Over the years, we have updated the model several times, and this value is different than the IPE value.

MEMBER KRESS: Okay.

MR. DAIBER: In a similar fashion, then, we accounted for the effects of power uprate, and came up with a change in the large earlier release frequency, the LERF. The delta LERF was $9.3E^{-8}$, which is a 24 percent increase associated with power uprate.

This fell within Region 3, which was a very small change from Reg Guide 1.174.

MEMBER KRESS: That LERF is almost two orders of magnitude lower than your CDF.

MR. DAIBER: Yes.

MEMBER KRESS: Is ANO2 a large dry?

MR. DAIBER: Yeah, it's typical for a large dry EWR.

MEMBER KRESS: So that's why you get that kind of --

MR. DAIBER: That is correct.

As I mentioned, we also looked at the external event considerations-- fire, seismic considerations, shut-down risk considerations. And when we did those assessments, we looked to see if there was anything unique about power uprate. And doing those assessments, we determined there were no unique or significant insights to be gained as associated with the power uprate impacts on the plant.

So in summary, we've looked at the plant from --

MEMBER POWERS: Are you changing any electrical equipment at the plant?

MR. DAIBER: Major electrical equipment, no.

MEMBER POWERS: No transformers are changed?

MR. DAIBER: No. The transformers themselves --

MEMBER POWERS: No relay being changed. That doesn't affect your fire?

MR. DAIBER: No, not in a fire-initiating event frequency consideration.

MEMBER POWERS: How can it not?

MR. DAIBER: I'm sorry?

MEMBER POWERS: How can it not?

MR. DAIBER: Affect the fire frequency?

MEMBER POWERS: Sure.

MR. DAIBER: Mike, are you aware of the basis for the combustible loading considerations with respect to fire?

MR. LLOYD: My name is Mike Lloyd. I'm the ANO lead engineer in PSA area.

We did a separate fire analysis, and I don't -- that part of the analysis was done by our fire protection folks. They did a fire loading. And the loading itself considered those aspects of the plant. I don't believe that the increase loading, however, was explicitly considered. But there are large, I guess -- degree of conservatism in the fire

analysis that we did perform. We used the five methodologies, an EPRI method.

MEMBER SIEBER I guess we're talking specifically about the main unit transformer.

MR. DAIBER: Yes.

MEMBER SIEBER That's located outside?

MR. LLOYD: Right. That is correct.

MEMBER SIEBER Is that away from the buildings.

MR. LLOYD: Yes.

MEMBER SIEBER Twenty or 30 feet?

MR. LLOYD: Yes.

MEMBER SIEBER Do you have a dike around it?

MR. LLOYD: I'm not -- yes, there's a dike around it.

MEMBER SIEBER And it has water suppression? Automatic water suppression?

MR. LLOYD: Yes.

MEMBER SIEBER Okay. Thank you.

MEMBER POWERS: Have we ever had transformer fires at nuclear power plants?

MEMBER SIEBER Pardon?

MEMBER POWERS: Have we ever had transformer fires at nuclear power plants?

MEMBER SIEBER Yeah, I had two of them.

MEMBER POWERS: I mean, it just seems remarkable to me that we can do an analysis that says we've increased the power running through the transformer, and we didn't change the fire frequency.

MEMBER SIEBER Well, the initiation frequency should change because the linings are hotter. The potential fault currents, as long as the breakers continue to be interrupted, don't explode. That's usually not an issue. But the transformers are located anywhere from 20 to 50 feet from the nearest building. And I haven't seen -- even with major fires, I haven't seen it spread to the buildings. They seem to get trapped in the diked area.

MR. DAIBER: I would venture to say that that was one of the screen zones, below the 1 x 7^{-6}.

MR. LLOYD: But the impact of the fire, because of the exterior location of these transformers, would cause a loss of off-site power, yes. And we did evaluate the loss off-site power in our analysis. But that would be, I believe, the major effect of such a fire in that exterior to the plant location.

In addition, the location is very distant from the safety-related equipment. It's in the aux

building, which is quite distant from the location of the transformers.

MEMBER POWERS: Well, saying that the only effect of the fire and the transformer is to increase the frequency of loss of off-site power is not what I would call heart-warming. That's usually a fairly significant accident.

MR. LLOYD: We evaluated that. And I believe that roughly it represents about 5 percent of the CDF. It's not a major single contributor. And BWRs, typically this loss off-site power represents a much, much larger fraction of their risk.

MEMBER POWERS: It tends to be plants, specifically.

MEMBER SIEBER Typically, in a PWR, you have two buses fed from the system and two fed from the main unit. If you blow the transformer, then you lose two of the four, and then they automatically cross-connect.

Is that the way your plant is --

MR. LLOYD: Our unit has two divisions. Should we lose off-site power, what would happen is we would use on-site diesels, one emergency diesel powering each of the emergency buses. And in addition to that, quite distant from the transformers we have

another unit that's a station blackout unit which was installed for the station blackout rule. And it is a stand-alone island of power basically dependent on only itself for all intents of purposes. It has its own DC system for starting. It can be started from the control room. It has its own air cooling system. It's totally independent of service water. So it sits there ready to be used from the control room.

MEMBER SIEBER Okay.

MEMBER KRESS: Are there two units on that site?

MR. DAIBER: Yes.

MEMBER KRESS: About the same power level?

MR. DAIBER: Unit 1 is slightly lower. Thermal is 2856.

MEMBER KRESS: Is it the same kind of reactor and containment?

MEMBER SIEBER No.

MR. DAIBER: No. It's 25 --

MEMBER SIEBER It's a BMW.

MR. DAIBER: BMW.

MEMBER KRESS: It's a BMW.

MR. DAIBER: With that, we've looked at the plant both from a design capability standpoint to make sure all the components could operate properly

within the design criteria for the plant. We also looked at it from a risk perspective and verified from a risk perspective the plant and their operating conditions were acceptable.

With that, I'd like to turn it over to Craig Anderson for concluding remarks.

CHAIRMAN APOSTOLAKIS: Is the staff going to make a presentation, Jack?

MEMBER SIEBER Yes.

MR. ANDERSON: All right. Let me start off by thanking this committee for your time this afternoon. I'd just like to close by saying, our focus has been throughout this project -- as it should be -- in keeping the plant safe and reliable. And through analysis, through modifications, through training, we believe that we've done that.

Our plant, and our equipment, and our people are ready for the power uprate. And if there's not any additional questions, that concludes our portion of the presentation.

MEMBER SIEBER Okay. Well, I thank you and your staff and Entergy for putting together a good presentation that we can understand. And it appears to me like you have done a lot of work to get this unit ready to run at a higher --

MR. ANDERSON: Yes, sir.

MEMBER SIEBER Thank you very much.

MR. ANDERSON: Thank you.

MEMBER SIEBER What we'd like to do now is have the NRC staff come forward. And as they get set up for their portion of the presentation, which will discuss the Safety Evaluation Report, I would like to introduce to you someone we haven't seen for several hours, which is John Zwolinsky, who seems to show up for every operation.

MEMBER POWERS: He just can't stay away. We're so kind to him that --

MEMBER SIEBER So when you folks are all set, you can begin.

MR. ZWOLINSKY: Give us just a couple minutes. Thank you.

MEMBER SIEBER All right. No problem.

MR. ZWOLINSKY: Can I get started?

MEMBER SIEBER Yes.

MR. ZWOLINSKY: Great.

Good afternoon. To those of you that don't recall who I am, I'm John Zwolinsky, director of Division of Licensing Project Management in NRR. Joining me today are our management team and first-line supervisors that have overseen the review

of the Arkansas power uprate. I'd like to take a minute to identify those folks. They're here in support of our staff. And, certainly, we have a large number of staff here to answer any of the questions that may go beyond the agenda.

I'd first like to recognize Ms. Suzanne Black, our deputy director for the Division of Safety and Systems Analysis; Richard Barrett, our branch chief in the PRA Branch; Stu Richards, our project director for PD4.

We have a number of our section chiefs, our first-line supervisors. Bob Graham out of PD4. Frank Akstulewicz of Reactor Systems Branch will be making a presentation; Ralph Gruso of Reactor Systems; Kamal Manoly of Mechanical Branch; Brian Thomas from Plant Systems; Matt Mitchell from our Materials Branch; Corney Holden from our Electrical and Instrumentation Control Systems Branch; Louise Lund from our Materials Group; Mark Rubin from our PRA Group, at the table.

I feel it's important to ask the staff to join me for meetings such as this. We place high emphasis on bringing these to closure. And as you know, the Commission has placed a high degree of importance on power uprates in general, and I

appreciate our staff being here with me.

The staff is here to present its review of the 7.5 percent power uprate for the Arkansas Nuclear 1 Unit 2 plant. The staff made a presentation on this review to the subcommittee on thermal hydraulic phenomena on February 13, 2002.

The ANO2 uprate is the largest extended power uprate for PWR we have reviewed to date. The staff has conducted a thorough review of the Arkansas plant, focusing on safety. Reviews were conducted consistent with existing practices, which include the license arm from Main Yankee.

We used the Farley power uprate as a template for this particular review; that is, all the sections of Farley dictated the sections that we would review here. Scope and depth were driven to some extent by our standard review plan for various sections. We'll talk about that in greater detail throughout the presentations.

All areas affected by the power uprate were reviewed by the staff. The staff has critically examined the methodologies in their application for these power uprate requests, and concluded that the analytical codes and methodologies used for licensing analysis are acceptable for these applications.

Without further ado, I'd like to turn it over to Tom Alexion. Tom is our project manager for this plant and has shepherded this entire project from beginning to end.

Go ahead and get going, Tom.

MR. ALEXION: Thank you, John.

Good afternoon. I'm Tom Alexion. And I'm the NRC project manager assigned to Arkansas.

By way of background, the 7.5 percent power uprate application by Entergy represents the largest PWR uprate to date, as you heard earlier. The highest PWR power uprate previously approved was 5 percent.

Some background into the CE designed PWR. The architect engineer and constructor were BECHTEL. The full power license was issued on September 1, 1978. And the current license maximum reactor core power level is 2815 megawatts thermal. And it to has a large dry containment.

The steam generator was replaced in the fall of 2000. Some of the differences between the old and new steam generators are shown in this slide. The licensee designed the replacement steam generators to accommodate the increase in reactor power.

I would also like to note that when we're

doing the power uprate application, the NRR staff relied upon analysis previously done at the uprated power in support of steam generator replacement. And this is in the fall of 2000.

The NRR staff used the following power uprate as a guide for the scope and depth of its review. To further review guidance, the standard review plan is utilized. The staff have used their licensee's application of codes and methodologies to ensure that they are used within the appropriate restrictions and limitations, and to ensure they're appropriate at the higher power level. During the course of the review, the staff issued many requests for additional information. The licensees responded to all of them.

For the containment, the staff had a contractor perform independent calculations of the pre-containment pressures and temperatures following a postulated LOCA and main steamline break. In the area of vessel materials, the staff performed independent calculations of the pressurized thermal shock reference temperature and end-of-life upper shelf energy for each reactor pressure vessel material, and performed independent calculations on the susceptibility to vessel-head penetration

cracking.

In the area of dose assessment, the staff performed independent calculations of the atmospheric dispersion for the exclusionary boundary and low population zone, and the dose assessments for the LOCA, steam generator tube rupture, CEA ejection, and fuel-handling accidents.

In the area of risk assessment, the staff audited the licensees risk evaluation for power uprate, which included manipulating various parameter in the human reliability analysis spreadsheet, and did an independent calculation to gain a perspective of the seismic risk.

The principal areas of review are the NSSS and accident analyses, evaluation of structure, systems and components, BOP systems, human factors, radiological analyses, and risk assessment.

But for today, the order of presentation is as shown. We plan to present these four areas. And we're also going to show -- we have some examples where the staff focused this review.

When they were issued the draft safety evaluation, the only open items were in the radiological assessment area. But these items have been resolved. So, therefore, the NRR staff has no

open items.

And with that, those are my opening remarks. We can move to reactor systems, unless there are any questions.

MR. ZWOLINSKY: Frank Akstulewicz is our section chief responsible for this area. Chu Li Yang is senior staff reviewer.

MR. AKSTULEWICZ: Thank you. My name is Frank Akstulewicz. I'm the section chief in the PWR section of reactor systems. And to my right is Chu li Yang, who is the lead reviewer for this particular power uprate.

What I'd like to do is jump to Slide 2. Slide 2 identifies in general terms the areas of review that we focused on, and I'd like to make a few remarks about each of the bullets.

The first bullet specifically looked at the design operating characteristics and requirements for reactor coolant system ECCS and shut-down systems. And as you've heard today, there were very few modifications, if any, other than the steam generators, to these systems in order to support the power uprate. So our effort here principally was examining what the operating requirements were, verifying that the analyses supported those operating

requirements, and confirming that the analysis was done using acceptable methods.

The second area, fuel system design. Again, this particular power uprate does not use a new or different fuel type. It's the standard CE 16 x 16 array. The only thing different here is the poison. In this particular case, you've heard the licensee that particular effort. Thermohydraulically, it's no different than anything else that's used in other CE plants of higher power level. And analytically, we've done a number of accident evaluations using this fuel and have found no problems.

The last area, the LOCA and transient area, again, principally here we look at the specific initial conditions and assumptions used to assess the accidents. We look to make sure that the codes that are being used to assess those accidents are appropriate for application, and whatever the terms and restrictions are in those codes have been satisfactorily either resolved or complied with. Then we look at the results to make sure that from our experience and familiarity with how these transients should occur, whether the results are anomalous or not. And depending on the outcome there, we either pursue further information from the licensees or we

verify that it satisfies the acceptance criteria that's established for that particular transient, and approve the safety evaluation.

The two examples on the bottom will be more specific as two the actual nature of the review and some example -- maybe to the level of detail that we went into some of the assessments.

So with that, Chu will take over.

MR. YANG: My name is Chu Li Yang. I'm the reviewer for the Arkansas Unit 2 Power Uprate. And I'm going to discuss the staff review of feedwater line break and LSS performed by the licensee to support its power uprate.

As a part of power uprate, the licensee revised it's feedwater line break and LSS methodology. This slide presents some of the changes to the methodology and initial conditions and assumptions to perform it's power uprate reanalysis. However, the principal changes to the methodology involves -- proposed the use of low-level water trips at point associated with affected steam generator in their new analysis. And the previous low-level analysis -- low level trip of in tact steam generators was used instead of the affected steam generators.

And this methodology calculates the

limiting feedwater break size by concurrent high pressurizer, pressure trip and the low steam generator -- what level trip affects the steam generator in the new analysis.

The change of the methodology slight resulted in a reduction in margin. And also, the reanalysis assumed uprated power level. The changes also in the areas of initial conditions and assumptions, such as a high initial pressurizer larger, in mill steam safety of tolerance and early mill steam isolation. And those conservative assumptions were added to provide safety margin in the new analysis.

For review of changes in methodology, we accept everything of the changes and will be discussed next.

The acceptability of the revised methodology used in the new feedwater line break analysis is reviewed in the following steps.

First we consult INC staff regarding accuracy of the low-level trip set point on affected steam generator in the new analysis. INC staff concludes that the instrumentation of certainty calculations were acceptable for this application. Also, we look at the documentation for the NOTRUMP

computer code, and find that the code was initially reviewed with ability to evaluate the steam generator water level behavior and stability and damping predictions during feedwater line break dynamic conditions. And the staff concluded, NOTRUMP is acceptable for those specific areas of calculation. And inputs found in NOTRUMP computer code from the simulator steam generator -- and provide input to system transient code for primary system response simulation.

Finally, the approach used to taking credit for low-level trip affected steam generator is currently used in Westinghouse plants. And this approach has been approved in WCAP-9230 for Westinghouse steam generators. And based on those facts, we conclude that the approach of new level water trip in affected steam generator to giving credit for feedwater line break is acceptable for ANO Unit 2.

We would like to discuss the impact of the revised methodology.

The first bullet of this slide lists the major impacts found in the revised methodology. In the new analysis, the licensee indicated that the limited break size is slightly reduced from

approximately .17 square feet to approximately .15 square feet. And the reactor trip react early during the transient. In the steam generator, the water inventory is increased at the time of the reactor trip. And those changes result in slightly a reduction in margin. But the calculated peak transient primary and secondary pressures are slightly reduced. It's reduced to 2647 PSIA, and the previous analysis was 50 points higher.

The result of this analysis met all acceptance criteria specified in the SRP. And the peak primary and secondary pressures remained below 10 percent of the line pressure. The pressure lines would not go solid, and the DMB is not a concern for this event.

Next, we'd like to discuss the staff review of control or the withdrawal from subcritical conditions. This event is classified as AOO. And the staff acceptance criteria for this event does not allow fuel damage. The safety limit in existing text specs is the peak linear hit rate limit, less than 21 kilowatts per foot.

The licensee's power uprate analysis shows the transient linear hit rate approximately 40 kilowatts per feet, which is about the existing

text specs. However, the impact of this high linear hit rate limit is very limited by a short transient duration of less than two seconds. And the calculated peak fuel center line temperature is approximately 2800 degrees. And the results of the analysis shows all SRP acceptance criteria are satisfied with respect to fuel performance, fuel pressure and fuel center line temperature. And the licensee has revised the text specs to remove linear hit rate limit and include a fuel center line temperature limit value adjusted for fuel burn, which is roughly --

MEMBER POWERS: Would you say that again, please?

MR. YANG: The text specs have been revised. And the existing text specs, the linear hit rate limit is eliminated, and instead, the fuel center line temperature is defined as a limit for this event. It's consistent with SRP.

MEMBER POWERS: How does it change with burn up?

MR. YANG: It's adjusted for fuel burn up.

MR. AKSTULEWICZ: The fuel adjustment -- the temperature is actually decreased with burn up. It declines -- I think -- well, there's a proprietary restriction on actual number for CE.

But I can say that for Westinghouse plants, it's approximately 50 degrees per 10,000 megawatt days per ton.

MEMBER POWERS: Why do we think that's an adequate thing?

MR. AKSTULEWICZ: It defines the point at which the fuel centerline actually will begin to melt for this particular -- for these kind of power insertion events. It's a calculated value that's part of the design basis.

MEMBER POWERS: How do they calculate the melting point of the fuel?

MR. AKSTULEWICZ: It looks at the rate of reactivity insertion and the energy deposition within the fuel itself, and then does a temperature calculation, looks at the heat up of the fuel.

MEMBER POWERS: Yeah. But when does it melt? I mean, how do we know when it melts?

MR. AKSTULEWICZ: The -- it's assumed to melt when it reaches a certain temperature. And that temperature is based on experimental data that the fuel vendors have.

MEMBER BONACA: This is a bank withdrawal, right? Not a single rod.

MR. AKSTULEWICZ: No, this is single rod

withdrawal.

MEMBER BONACA: A single rod.

MEMBER SIEBER You mean a single rod out of its bank configuration, right?

MR. AKSTULEWICZ: Yes. This is a single rod being looped.

MEMBER SIEBER Otherwise, you can't go -- a single rod by itself won't do anything.

MR. AKSTULEWICZ: That's correct.

MR. ALEXION: Okay. If there's no further questions, we'll move on to the plant systems branch with Dave Cullison and Rich Lobel.

MR. CULLISON: Good afternoon. I'm Dave Cullison from Plant Systems Branch. With me is Rich Lobel also from the Plant Systems Branch. I perform the majority of the reviews of the power uprate. Rich did the containment reviews that were done as part of the replacement steam generator and containment uprate of the project.

My two slides I want to discuss just show the SRP sections we used in the performance, we used as guidance for completeness and accuracy. We determined in all our reviews that there's no significant impact on the system operations through the power uprate. And this is just the continuation

slide.

Rich is going to discuss the independent confirmatory analysis done for the containment response to the power uprate.

MR. LOBEL: Richard Lobel from Plant Systems Branch. As part of the replacement steam generator review, we contracted with Los Alamos National Laboratory to do a calculation -- confirmatory analysis of the calculations done by the licensee for the peak temperature and pressure for both a LOCA and a steamline break. They used the MELCOR code to do the calculation. But it was a designed basis calculation, so it didn't really exercise most of the models in MELCOR.

The analysis looked at, like I say, both the LOCA and the steamline break, and in general agreed with the licensee's analysis. The one area where there was a large discrepancy between the analysis was in the case of the steamline break, the licensee calculated a much more conservative temperature than we did. And after discussing it with the licensee, the licensee suggested that it might be an assumption they made for containment spray. They assumed a very low efficiency, very low heat transfer

from the atmosphere to the spray. And MELCOR used pretty much a physical model of the spray. We went back and adjusted the spray model and got fairly good agreement with the licensee's calculations.

When I talked to the subcommittee, I said that the report on this was available in ADAMS, and everybody laughed. So let me just say now that it's in ADAMS.

That's all I have, unless there's any questions.

MR. ALEXION: Okay. We'll move on to the Materials and Chemical Engineering Branch, and Barry Elliott will be the presenter.

MEMBER SIEBER Before we get to that, I'd like to ask what the ultimate heat sync is at -- is it a lake or river or --

MR. CULLISON: They have two. They have a pond, which is their -- and they also have the Dardinel Reservoir.

MEMBER SIEBER Okay.

MR. CULLISON: The one with -- that Rich reviewed, ultimately heat sync evaluations as far as steam generator replacement in the pond.

MEMBER SIEBER Okay. Thank you.

MR. ELLIOTT: I'm Barry Elliott with

Materials and Chemical Engineering Branch. This slide shows all the areas within our branch that we review. The first six items I'm not going to go over today. I'm going to go over the last three, which I think are the most significant, which is the reactor vessel integrity, steam generator tube integrity, and the Alloy 600 Program.

Before I go on, are there any questions about the first six items? No.

The Alloy 600 Program is intended to take the primary water stress corrosion cracking of Alloy 600 and Alloy 182 wells and the reactor pool and piping, the pressurizer and vessel head penetrations. Cracking in vessel head penetrations were the subject in NRC Bulletin 2000 and '01. PWRs were ranked by their MRP, according to the operating time and temperature, and effective full power years required for the plant to reach the effective time and temperature corresponding to the Oconee 2 event, where they had crackings -- circumferential cracking in their Alloy 600 head penetrations.

Plants with high susceptibility to primary water stress corrosion cracking are those which are predicted to have a ranking of less than five effective full power years from the Oconee 3

condition. Plants with a moderate susceptibility to primary water stress corrosion cracking are those which are predicted to have a ranking of more than five effective full power years and less than 30 full power years from the Oconee 3 condition. Depending on which ranking you are determines which inspection program you're involved in.

In the case ANO2, before the uprate, they were in the moderate category, and after the uprate, they're still in that category. The uprate increases the T-hot temperature from 604 to 609. Increase in T-hot will not substantially increase primary water stress corrosion initiation and growth rate; however, it does affect the ranking somewhat.

Potential for primary water stress corrosion cracking developing in Alloy 600 nozzles will not be significantly affected by the power uprate, and, therefore, there is no change in the Alloy 600 and the vessel head penetration inspection program as a result of the power uprate.

MEMBER POWERS: Somehow this uprate will increase T-hot form 604 to 609, and then say that won't increase the primary water stress corrosion cracking initiation and growth rate didn't strike me as quite what you mean here.

Don't you mean that, though they have a T-hot going from 604 to 609, that's not what the temperatures of the head --

MR. ELLIOTT: There's two issues here. There's a head issue, and then there's a piping issue.

MEMBER SIEBER They're different.

MR. ELLIOTT: The intent of that lip was the piping and pressurizer issue.

MEMBER POWERS: Oh, okay.

MR. ELLIOTT: The head is -- it has a lower temperature than the head -- than the piping and the pressurizer.

MEMBER FORD: I've got no quarrel at all with what you put down there, except that it is, as Dana intimated, fairly qualitative. And although you're quite right, it still remains in the moderate range, that temperature time, erraneous type metric that is being used is pretty rough. The times are still fairly short in absolute terms -- 5, 15 years -- compared with license-renewal time schedules.

During your thought on this -- during your analyses of this -- was there any quantification along these lines?

MR. ELLIOTT: Well, the quantification is -- the purpose of the Bulletin 2000 and '01 is to

determine the inspections that are going to be occurring at the next refueling outage.

MEMBER FORD: Correct.

MR. ELLIOTT: So the whole point of it is, is to get how susceptible your plant was to decipher cracking. If you were very susceptible, then you had to do some more inspection. And it was just -- based upon the models that were developed as part of the MRP, you were put into different categories. And that was the intent, to determine what kind of inspection is required at the next refueling outage. The model itself was developed from data of material crack growth.

MEMBER FORD: Yeah. But pretty well, every plant which is in the first category has, in fact, shown cracking.

MR. ELLIOTT: Right.

MEMBER FORD: So can we expect cracking on this plant within the next three years?

MR. ELLIOTT: Well, according to our model, it won't be.

MEMBER SHACK: Well, we have cracking at Millstone, right, at 14 years.

MEMBER FORD: Right.

MR. ELLIOTT: It could. I mean -- when

they do the inspection --

MEMBER SHACK: But they're going to do the inspection.

MR. ELLIOTT: -- we'll find out. They're going to do a volumetric inspection, which should be able to detect these cracks.

MEMBER FORD: As part of a process, I'm asking, this plant will crack. And it will crack before the end of its life.

During your reasoning, does that come at all into your arguments?

MR. ELLIOTT: You mean that the plant will eventually crack?

MEMBER FORD: Yeah. I mean, is it a thing that comes into your --

MR. ELLIOTT: I think the issue is -- as you say, it will eventually crack --

MEMBER FORD: Sure.

MR. ELLIOTT: -- and it will crack before the end of 40 years probably. But that becomes -- as long as we have an inspection program that is capable of detecting the cracks before they become critical and affects the integrity of the reactor coolant system, that's all we're looking for. We're looking to make sure that's there.

MEMBER FORD: But that important fact is not set out there. And that's reassuring, your saying that. Again, for the public confidence aspect, it's useful to have that enunciated.

MR. ELLIOTT: Well, we're relying on an inspection program to detecting these cracks before they become critical.

MEMBER FORD: Right.

MR. ELLIOTT: And that's what the model is intended to do, to lay out what we suspect to be the worst plants, and that they need more inspection than the less susceptible.

However, this plant, even though they're in the moderate category, is still doing a volumetric, which is very good.

The next slide deals with reactor vessel integrity. Just a quick background for you who are not knowledgeable.

10 CFR 50 establishes a Scharpey upper-shelf screening criteria. And 10 CFR 50.61 establishes RTpts screening criteria for pressurized thermal shock.

The licensee has made evaluations of the upper-shelf energy and the RTpts values, and they're done in accordance to Reg Guide 1.99, Rev 2. For this

plant, the materials have a low rate of brittlement. The upper-shelf energy is predicted to drop even with a power uprate of only 60 foot pounds. And the RTpts value is around 120 only, which is 150 degrees below the screening criteria in the pts rule.

The staff reviewed these calculations. I want to point out also, we also reviewed in the previous slide the Alloy 600. We did our own susceptibility calculations.

We did the calculations here for the upper-shelf energy and the RTpts values. In addition, Appendix G requires pressure temperature limits. And from those pressure temperature limits, low temperature over-pressure set points are determined. These limits in set points were provided in a separate application and are being reviewed by the staff to ensure that they meet all regulatory requirements. Based on these analyses, the reactor vessel meets all regulatory requirements.

As far as steam generator integrity, the Alloy 690 tubes are more resistant to stress corrosion cracking than the Alloy 600 tubes. Degradation of tubes resulting from the deposition of copper was eliminated by removing copper from the secondary side. We've done analysis of vibration or frequency

responses of antivibration bars, minimized wear. Reg Guide 1.121 analyses were performed to ensure structural integrity. And based upon this analysis and the changes in the system, there is no change in the tube inspection program required at this time.

That completes my presentation today.

MR. ZWOLINSKY: Thank you, Barry.

MEMBER POWERS: When you say there's no need to change the tube inspection program, you mean that there's no need to increase it, right? That's all you looked at.

MR. ELLIOTT: I --

MEMBER POWERS: You need to look at the possibility --

MR. ELLIOTT: The inspection program is a text spec item, and is a certain program they have to follow. This will not change that.

MS. LUND: Right.

MEMBER POWERS: You didn't look at the possibility that they could increase or decrease their inspection.

MS. LUND: It wasn't considered under just the power uprate situation. We're evaluating that separately under the NEI-97-06. And we're still -- as you know, we're still evaluating that.

MEMBER POWERS: Okay.

MR. BOEHNERT: Can you identify yourself for the record, please?

MS. LUND: Oh, I'm sorry. It's Louise Lund of Component Integrity and Chemical Engineering section.

MR. BOEHNERT: Thank you.

MR. ZWOLINSKY: If I might play off your interest in the bulletin that Barry alluded to. We continue to receive information from licensees conducting inspections. They are finding cracks. And our challenge going forward are our next steps. And this program matures over the next couple of years -- you're probably aware, many licensees have committed to head replacements. And the concept or thought of inspecting at every cycle seems to be not the best answer. So we still have our challenges before us. But as we go forward through the spring outages, it may be appropriate to come back to the committee and give you a status report essentially one year later, so to speak, with the fall outages having taken place.

MEMBER POWERS: An issue I'd like to know more about is what is the risk importance described in the vessel head.

MR. ZWOLINSKY: The vessel head or the independent CRDMs?

MEMBER POWERS: Either one or both.

MR. ZWOLINSKY: Part of the basis of the bulletin when it was developed was the lost of one of the CRDMs.

MEMBER POWERS: Yeah, I understand the bulletin. I guess I'm asking the probablists in this, if I tried to guide a risk importance parameter for the vessel head -- who are the CRDMs housings from a PRA -- what number would I get?

MR. BARRETT: This is Richard Barrett. I'm with NRR staff.

We have been looking at this question of the risk significance of the CRDM cracking issue. And clearly there are two important questions. One is, for any given situation, for any given head at any given time, what's the probability that it would result in a LOCA. And I think we're talking about a medium LOCA. And then the second question is what is the conditional probability that that LOCA would then lead to a core damage accident, and then possibly only to a LERF, large early release.

The second part of the equation is the easier part. You can look that up in most PRAs, and

it's of the order of conditional probabilities of 1 in 1,000. The first part, however, is much more difficult to assess. And it has to do with your perceptions as to the initial conditions of the head, of a particular CRDM, in terms of the probability that a crack exists, the size of the crack, the depth of the crack, and then the crack growth rate. And the type of analysis that is required is not that different from the kind of analyses that we've been talking about in the context of 97-06 for the steam generator tubes.

In the fall of this year, we went through a lot of what I'll call qualitative analysis in trying to resolve -- make our regulatory decisions with regard to the operation of the high susceptibility plants, and proposals that were made by various licensees as to the schedule for when they wanted to shut down.

But I think as we go forward, we need to get a better handle on this. And we're working with our Office of Research who are developing and refining models for crack initiation, crack growth, and how that relates to the probability of a catastrophic failure. It's not an easy question to answer, but we're working on it.

MEMBER POWERS: Good.

MR. ZWOLINSKY: Okay.

MR. HARRISON: Good afternoon. I'm Donny Harrison. I was the lead for the PRA part of the review.

We can just move to the second slide. This slide just identifies the -- I think you've heard this before a number of different times, primarily with BWRs, but we look at the internal events, external events, shut-down operations. And we look do a look at their PRA quality. We do that to see if there's any insights and just to confirm that there's no new vulnerabilities being created as part of a power uprate.

MEMBER POWERS: Let me ask you what the significance of looking at the IPEs and the IEEEs for this plant is. The previous speaker told us that he modified his plant, and PRA all over the place. So why would you bother to look at the IPE?

MR. HARRISON: Often times you'll see in IPE and IPEEE either a statement -- an example of that would be the seismic area for Arkansas. They do a seismic margins analysis. In the process of doing that analysis they make assumptions that they've fixed things. We come back, and I take a look at that, and

I then send a request for additional information to the licensee and say, did you fix it?

The thing we found out at Dresden was, in one area, no. That's worth knowing. For Arkansas, the answer was yes. Everything we took credit for that we used in that analysis we've now fixed, and we fixed it the way we said we were going to fix it. And it meets the assumptions of the IPEEE, so it gives you really some confidence that the IPEEE now actually reflects the plant that's there.

MEMBER POWERS: But here we know that the IPE does not reflect the plant that's there.

MR. HARRISON: Right. The IPE even still may say during a technical evaluation, the staff found weaknesses in initiating event frequencies. I think one of the comments that was made on Clinton was that it was a new plant, and they didn't have a whole lot of plant-specific data. So you can look and see what has the plant done in response to what the IPE or IPEEE found.

In a way, it's kind of a way to check to make sure that plants are improving their analysis and not just using the same old analysis and staying with it, not changing.

CHAIRMAN APOSTOLAKIS: You said the magic

words, improving the analysis. I think -- I mean, you are not responsible for people's models and so on. But, unfortunately, your silence may be misunderstood.

I see here in Section 8 a fairly detailed analysis of the operator actions that affect it. And that's the safety evaluation.

MR. HARRISON: Right.

CHAIRMAN APOSTOLAKIS: And the licensee says that they used three EPRI reports to come up with human error probabilities. And you have a table here where, for example, for failure to reenergize such and such and such from SD2, the pre-power uprate available time was 42 minutes, and the HEP was .19, and the post-power uprate available time was 39 minutes -- three minutes down -- and the HEP was 2.9×10^{-1}. And then you go on and have a very nice discussion of how you really wanted to make sure that there were no other operator actions that were left out and not evaluated, and I think that's very good. The thing that bothers me, though, is that I don't think there is a model anywhere in the world that can tell the difference between 42 minutes and 39 minutes and produce a number like 2.9×10^{-1}.

Now you are very carefully here saying, the staff finds, based on the information provided by

the licensee and the staff site review, that the licensee's human reliability analysis application is consistent with their identified methodologies-- a beautiful statement. It says nothing. Right?

But then you go on and say, and that the assumed increases in the HEP values for the identified operator actions reasonably reflect the reductions in the times available for the operators to perform the necessary actions.

Now, I don't know how you've gotten it. I suspect you're right. But you didn't get it from the EPRI methodologies. Now, a minor reduction in time tells me that the performance of the operators are expected to be more or less the same as it was before. But to say in a table that the number went from 1.9×10^{-1} to 2.9×10^{-1}, I mean, is an illusion.

MR. HARRISON: Right.

CHAIRMAN APOSTOLAKIS: And I would expect you to say that this methodology -- I mean, find nice words -- that these methodologies are not widely acceptable; they have not been approved by the NRC. You know, something to that effect. Because, frankly, they are not widely acceptable. That's why this agency has spent a lot of money trying to develop ATHENA. That's why the French are spending a lot of

money developing MERMOS, the Fins are spending a lot of money developing something else. If EPRI had done it, we wouldn't be doing this.

So I think your silence on this may be misconstrued by other people. Now, I realize it is not your job to evaluate human reliability models, but you should not accept uncritically results such as this one.

Now your sentence here is really beautiful, but I would expect it to say something more than that. The fact that something is consistent with some methodology, the numbers, I mean, what does that tell me? Not much. Although, the ultimate conclusion -- I mean, this is the day where the conclusions seem to be reasonable, but the models that led to them are terrible. Not terrible. Not terrible. You know, they're still in evolution.

I think your conclusion is okay, that the times probably are not affected that much, and the human error probabilities are probably the same as they were before. But to go ahead and produce a delta CDF of 3×10^{-6}, I just don't believe that. If the major input of this calculation is these human error probabilities, I don't believe it.

Now, is it much larger than that? I don't

believe that either. Should you deny their request? Based on this, no. I'm not saying that either. Okay? And what perplexes me is that this is not a risk-informed application. So whatever you're presenting here really does nothing, does it?

But I just can't let it go. This is a difficult situation here. I don't think the licensee should be penalized for this. But, you know --

MR. HARRISON: I'm glad you bring it up. Because just as an analyst, I get concerned when we focus too much on the numbers, and we don't sit back and say what did the plant learn from all this. If we're just focused on did the number go from .1 to .2 --

CHAIRMAN APOSTOLAKIS: Well, if you had written it that way, I would be much happier. Because I really appreciate the difficulty that you're in. Your job is not to evaluate at-risk models or whoever models. But if somebody says, I used these models, and here are my numbers, and you say nothing, then, I mean, we have a problem there.

MEMBER KRESS: But 1.174 says you have to come up with a number.

CHAIRMAN APOSTOLAKIS: Well, I'm sorry. But that's not the number.

MEMBER KRESS: How would you have come up with a number is my question.

CHAIRMAN APOSTOLAKIS: I couldn't. I mean, if you don't have a model, why should you come up with a number no matter what? You just don't have it. Maybe you can give a bounding value, change the attitude completely and say, look, I don't have model, but I don't think that such and such and such. But to say I use this model because --

MEMBER SHACK: But isn't that what the result is saying, is it didn't change all that much?

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER SHACK: Maybe you don't believe either number or the notion that it didn't change all that much, is what you're --

MR. HARRISON: And it becomes a relative decision, not an absolute.

CHAIRMAN APOSTOLAKIS: But my problem is that, if this is not in there, the next guy will say, oh, they used the EPRI methodology; that's pretty good. The staff didn't say anything.

MEMBER SHACK: But now you know --

CHAIRMAN APOSTOLAKIS: What?

MEMBER SHACK: Now you know why none of these applications are ever risk --

CHAIRMAN APOSTOLAKIS: Why don't we just eliminate all the risk references? I don't know what all this means.

MEMBER BONACA: But it's remarkable. You go from 122 minutes to 113 minutes, and they have a distinct difference in number. How you figured that out, I don't know.

CHAIRMAN APOSTOLAKIS: Yes.

MR. HARRISON: That's just an analytical -- it's an analytical exercise.

CHAIRMAN APOSTOLAKIS: It's not use of the concept of model.

MR. HARRISON: All right.

CHAIRMAN APOSTOLAKIS: So I don't know what to say. On the one hand it doesn't matter; on the other hand, you know, it's a document of the agency.

MEMBER KRESS: Well, when you have a LERF --

CHAIRMAN APOSTOLAKIS: Tell me. I mean, why is this agency spending all this money developing ATHENA if one can pick up the EPRI reports and do this? Why? Because there's a different group?

MR. HARRISON: We already took care of ATHENA.

CHAIRMAN APOSTOLAKIS: I'm completely confused now. I mean, we spent more than a million dollars.

MR. HARRISON: We already took care of ATHENA.

CHAIRMAN APOSTOLAKIS: Huh?

MR. HARRISON: We already took care of ATHENA.

CHAIRMAN APOSTOLAKIS: Because of this.

Anyway, you understand where I'm coming from. I mean, I'm not criticizing you, because that's not your job. Well, maybe a little bit I am. Better words.

I mean, I thought this was brilliant. "The licensee's human reliability analysis application is consistent with the identified methodologies." Brilliant.

MR. HARRISON: And that's about all I can say.

CHAIRMAN APOSTOLAKIS: It sounds good, and it says nothing.

MR. HARRISON: Okay, enough.

MEMBER SIEBER Yes, why don't we move on.

MR. HARRISON: Okay.

The bottom line, though, to answer your

question, is as our review, the only -- if you want to say the only value is, is it's a negative review of looking for is there an issue out there that's going to come up on some plant down the road -- it didn't happen here -- that puts us into an adequate protection question.

CHAIRMAN APOSTOLAKIS: And I think this is a very good point.

MR. HARRISON: And at that point -- and I would say, if a plant like Turkey Point came in that did the five methodology too and got a real high number, and they've got a high IPE value -- I don't know what their PRA number is now -- we'd want to look at that.

CHAIRMAN APOSTOLAKIS: Actually, the part that you did where you really questioned whether there were additional operator actions that the licensee did not address and so on, that was really nice. That was really nice. I think you did a good job there. It's the quantification that bothers me.

MEMBER KRESS: Well, in terms of quantification, the fact that the LERF, whether you believe the bottom-line number or not, is around 10^{-7}, tells me that you've got a pretty good plant here.

CHAIRMAN APOSTOLAKIS: I agree with that

too. Because even if you increase it by a factor of 100 --

MEMBER KRESS: That's right.

CHAIRMAN APOSTOLAKIS: But I would much rather see something like that than saying, is EPRI such and such.

MEMBER KRESS: So I didn't pay much attention --

CHAIRMAN APOSTOLAKIS: Well, I am. I am paying attention.

MR. HARRISON: No, I appreciate the input. Because, again, like I said, one of the concerns I have as an analyst is an overfocus on trying to get the precise number and worrying about did the CDF go up by 1 percent, when the ultimate answer is adequate protection, and am I up at 10^{-3}.

With that, actually, I really won't bother to go on.

CHAIRMAN APOSTOLAKIS: I'm sorry that I had to say all these things.

MR. HARRISON: Oh, that's okay.

CHAIRMAN APOSTOLAKIS: It wasn't you.

MR. ALEXION: That concludes this staff's technical presentation. I just have one last slide I'd like to show. And that is our conclusion. We

felt we've done a thorough review, they're extensive. We spent a lot of time on RAIs, a lot of information's been communicated. We don't have any open items. We feel the application meets applicable regulations. And the NRR staff recommends approval of the power uprate application.

MR. ZWOLINSKY: And I'd like to also take just a minute to thank the committee for this opportunity to present our review of the Arkansas extended power uprate.

As you've heard, the vast number of sections and the review areas that the staff has addressed and the independent analysis performed is to me quite impressive. And I trust the committee finds it the same way. I'd certainly recommend approval for this particular power uprate. Thank you so very much.

MEMBER SIEBER Thank you and members of your staff. I read the SER more than once, and I found that it was pretty well organized, which I think in part is because of the existence of the Farley SER in the work that have been done by the applicant. And it was pretty easy to read. And I thought that it was important to tell us about confirmatory calculations and the analysis that you did so that we can appreciate that the SER is not a rubber stamp; that

it's actually an independent analysis and confirmatory calculations. And to us that's important. It allows us to be able to see what the basis is when you say that this plant is satisfactory or the requested amendment is satisfactory.

So if there are no questions from the members at this time, Mr. Chairman, I give it back to you.

CHAIRMAN APOSTOLAKIS: Thank you very much, Jack.

We'll recess until 3:40.

(Whereupon, the foregoing matter went off the record at 3:27 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: 490th ACRS Full Committee Meeting

Docket Number: (Not Applicable)

Location: Rockville, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Pippa Antonio

Pippa Antonio
Official Reporter
Neal R. Gross & Co., Inc.

RISK-INFORMED PART 50
SPECIAL TREATMENT REQUIREMENTS
RIP50 OPTION 2

ACRS
MARCH 7, 2002

OPEN

Timothy Reed
Division of Regulatory Improvement Programs
US Nuclear Regulatory Commission

BRIEFING OBJECTIVE

- **Discuss highlights from ACRS subcommittee briefing (2/22/02) focusing on the remaining key issues that require resolution to establish categorization requirements and guidance for Option 2**

OVERVIEW OF CATEGORIZATION ISSUES

- Staff sent NEI 3rd round of comments on NEI 00-04 on 2/8/02–the comments contained therein are the issues the staff concludes need to be resolved

- Comments reflect both pilot activity feedback and staff review of draft revision B of NEI 00-04

- Staff is largely in agreement with NEI categorization guidance

- Major issues remaining:
  - -- Long term containment integrity
  - -- IDP guidance to support qualitative discussion
  - -- Use of the peer review process (NEI 00-02) to support the Option 2 categorization process

- Staff's issues appear to be technically resolvable

- Staff will come back to ACRS during the proposed rule concurrence stage to discuss the revised NEI 00-04 guidance

SUBCOMMITTEE MEETING KEY POINTS

- Some ACRS S/C members expressed concerns regarding the lack of an underlying basis for the Option 2 categorization process that would enable the ACRS or public to easily conclude the process is robust. Specific issues include:
  - -- factor to increase nominal failure rate for calculating risk increases
  - -- "guideline" RAW and F-V values
  - -- use of screening/margins approaches
  - -- parametric as well as modeling uncertainties
  - -- modeling/inclusion of CCFs
- Some ACRS S/C members would like studies to be performed and documented to show that the above issues are either not significant or dealt with appropriately
- Some ACRS S/C members would like the NEI 00-04 guidance to be enhanced to provide more structure to the IDP guidance

SUBCOMMITTEE MEETING KEY POINTS CONT'

- NEI noted that NEI 00-04 is an interim product -- expects it to change due to pilot feedback and staff comments

- ACRS will reserve its final judgement until the NEI 00-04 guidance is finalized

CONCLUSION

- **Staff will meet again with ACRS at the proposed rule concurrence stage to discuss NEI 00-04 and categorization requirements**

- **Staff recognizes that NEI 00-04 is an interim product and does not expect ACRS to provide an exhaustive list of issues and concerns at this time**

- **If the ACRS has major issues (that require resolution to gain ACRS endorsement) with the current approach to categorization, then the staff requests an ACRS letter**

- **Staff believes the ACRS S/C meeting provided valuable input to the process of developing categorization guidance and appreciates the committee's efforts**

Presentation to the Advisory Committee on Reactor Safeguards

CONTAIN 2.0 Studies for Clinton EPU

March 7, 2002

Edward D. Throm

Senior Reactor Engineer
Plant Systems Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

Telephone: (301) 415-3153

OPEN

Approach:

Modified an existing Mark III CONTAIN 2.0 model to represent Clinton for the studies — to qualitatively check the M3CPT and SHEX results:

- **Drywell, wetwell and containment volumes and initial conditions (p,T and relative humidity)**
- **Use M3CPT and SHEX mass and energy releases provided by licensee**
- **Performed three studies**
  - **RSLB short term pressure response**
  - **MSLB short term pressure response**
  - **RSLB long term temperature response**

Results:

Qualitative comparison of CONTAIN 2.0 studies to M3CPT and SHEX results confirm staff conclusion that the licensee's containment pressure and temperature response calculations are acceptable.

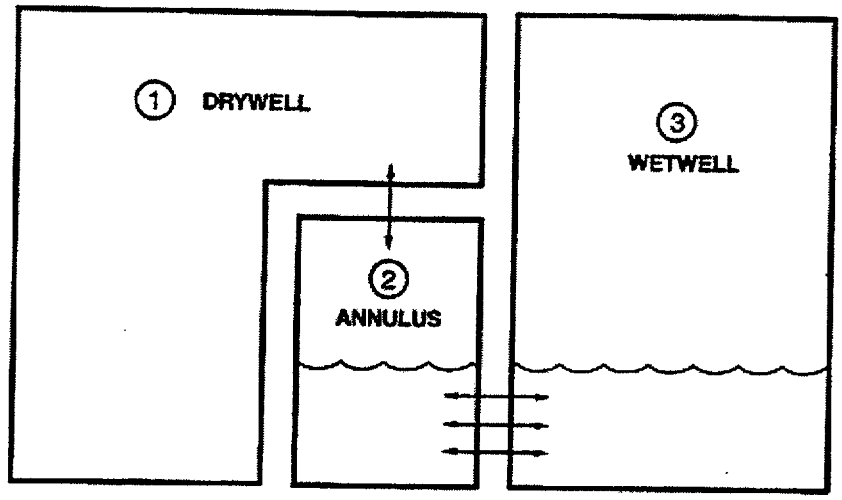


Figure 4-2. CONTAIN three-cell model of a Mark III BWR.

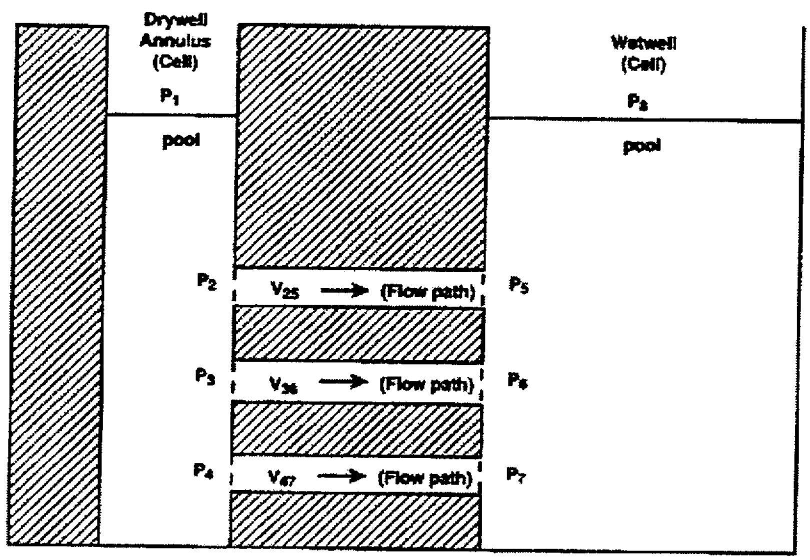
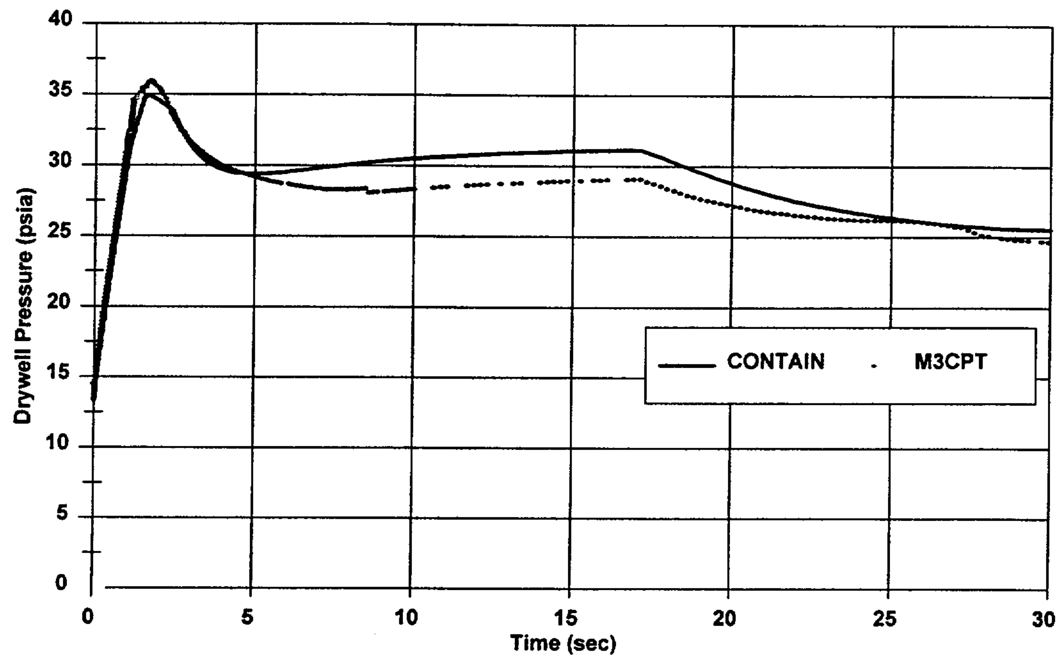
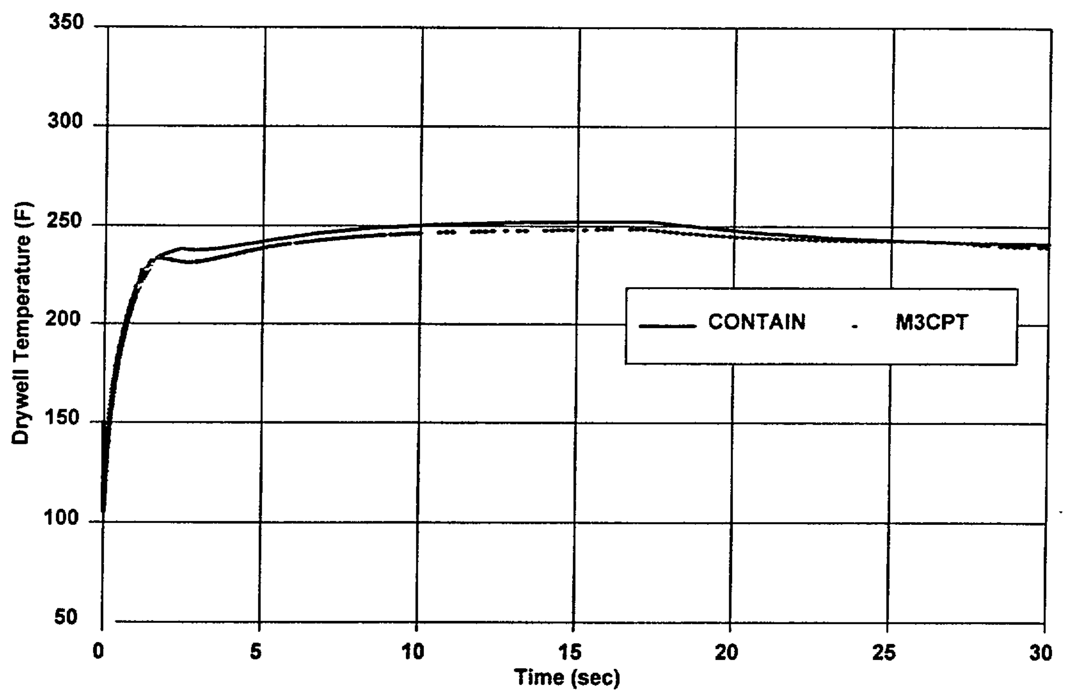


Figure 4-3. CONTAIN three-node representation of Mark III suppression vents.

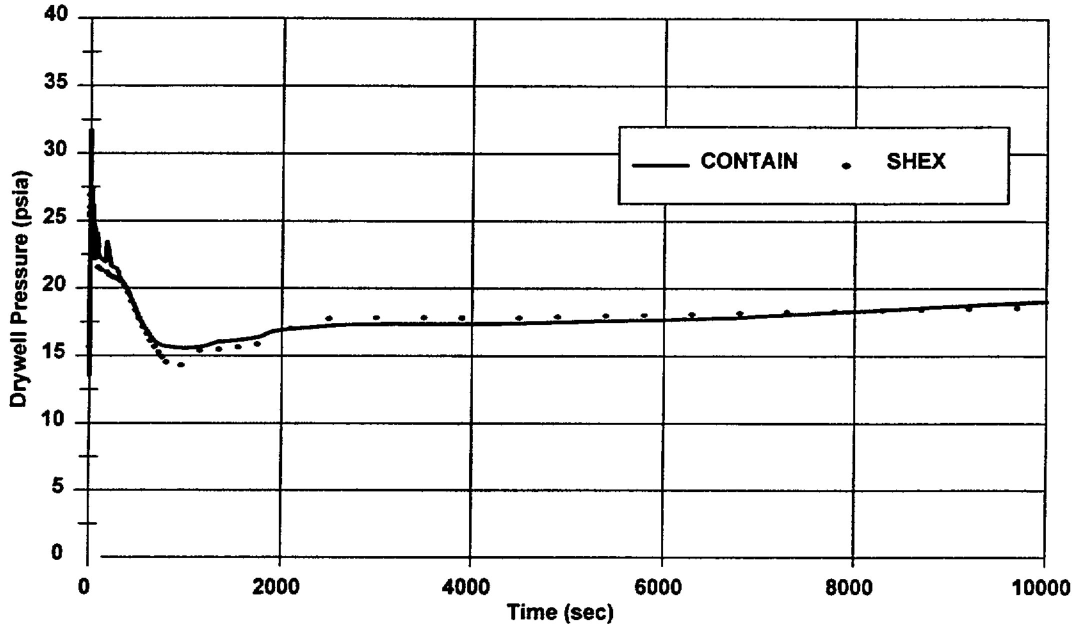
Clinton EPU RSLB



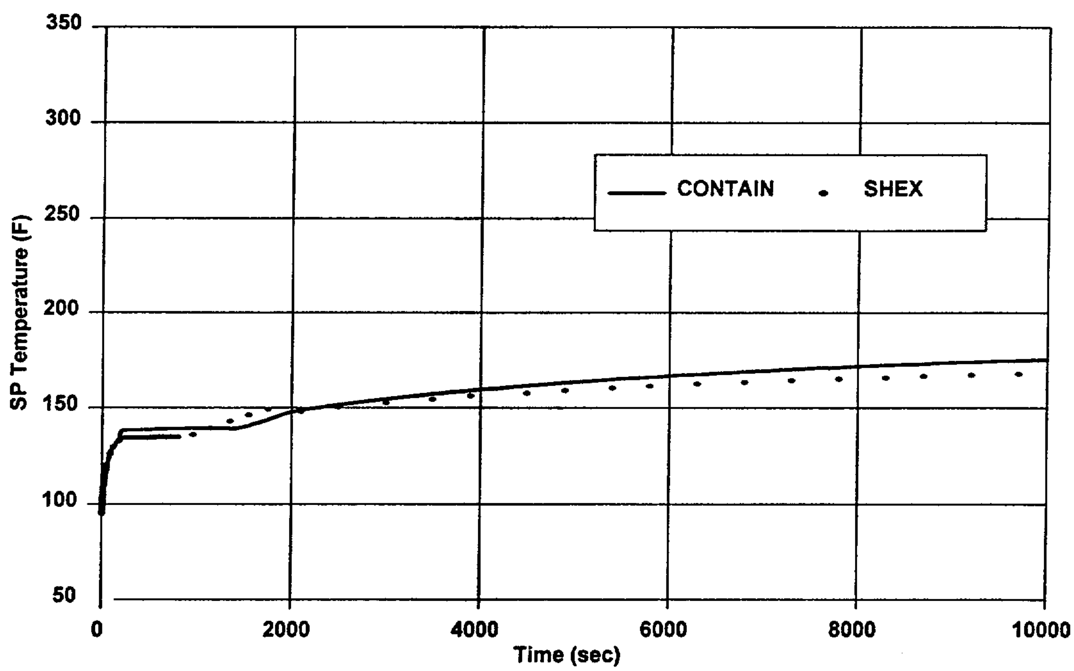
Clinton EPU RSLB



Clinton EPU RSLB Long Term



Clinton EPU RSLB Long Term



Extended Power Uprate

Clinton Power Station, Unit 1

AmerGen Energy Company, LLC
presentation to
Advisory Committee on Reactor Safeguards
March 7, 2002

OPEN

Agenda

- Introduction
- Project Summary
- Modifications
- Selected Analyses
- EPU Risk Evaluation
- Project Implementation
- Conclusion

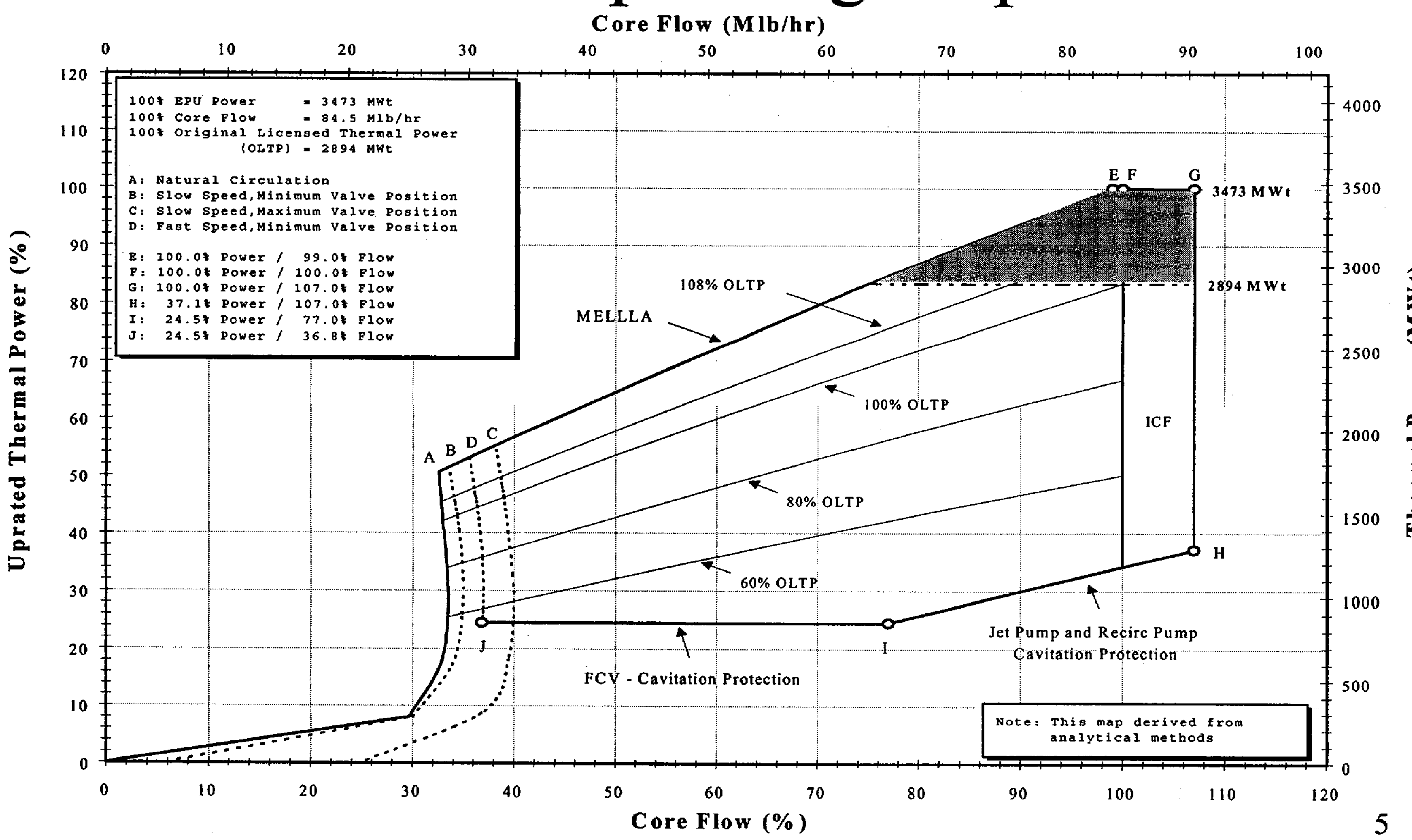
Introduction

Dale Spencer, Exelon Nuclear
CPS EPU Project Manager

Introduction

- Project Goals
  - Safely increase licensed thermal power by 20%
  - Use accepted methodology
  - Perform plant modifications to improve performance
  - Increase the electrical output of CPS
- Project Overview
  - Two step phased implementation
  - Few changes to safety-related SSCs
  - Plant will be balance of plant (BOP) limited following uprate

Power/Flow Operating Map for EPU



Current and EPU Operating Conditions

Parameter	Current Rated Power Value	EPU Value
Thermal Power (MWt)	2894	3473
Vessel Steam Flow (Mlb/hr)	12.4	15.1
Full Power Core Flow Range		
Mlb/hr	63.4 to 90.4	83.7 to 90.4
% Rated	75 to 107	99 to 107
Dome Pressure (psig)	1025	No change
Dome Temperature (°F)	549.4	No change
Turbine Inlet Pressure (psia)	982	954
Full Power Feedwater		
Flow (Mlb/hr)	12.4	15.1
Temperature Range (°F)	370 to 420	380 to 430
Core Inlet Enthalpy (BTU/lb)	527.8	525.5

Plant Modifications & Analyses

Dale Spencer, Exelon Nuclear
CPS EPU Project Manager

Plant Modifications

- Phase 1, C1R08 safety-related changes
  - Nuclear Instrumentation
  - No safety-related hardware changes required

Plant Modifications

- Phase 1, C1R08 BOP Modifications
  - High Pressure Turbine Replacement
  - Main Power Transformer Replacement
  - Isolated Phase Bus Duct Cooling Improvements
  - Replace Generator Hydrogen Coolers
  - Increase Generator Hydrogen Pressure
  - Replace Generator Excitation Anode Transformer
  - Upgrade five Feedwater Piping Supports

Plant Modifications

- Phase 2 - Proposed BOP Efficiency Improvements
  - Main Condenser Improvements
  - Condensate Polisher Flow Balancing
  - Moisture Separator Reheater Chevron Replacement
  - Switchyard and Relaying Upgrades
  - Generator Excitation System Upgrade
  - Bus Duct Cooling and Configuration Upgrades

Summary of Selected Analysis and Evaluations

- Core and fuel
- Containment
- Exceptions to ELTR 1/2 Requirements
  - ECCS performance
  - Transient events
  - Thermal-hydraulic stability
  - Large transient testing
- ATWS event response
- Flow accelerated corrosion

Core and Fuel

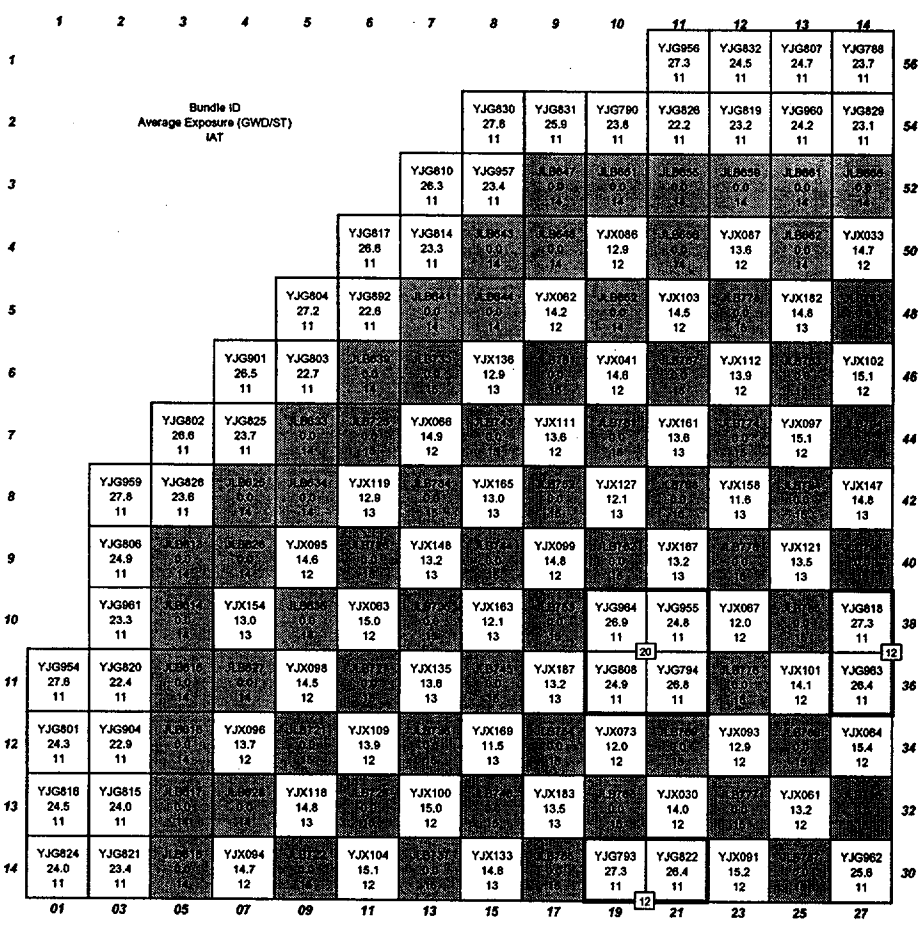
Fran Bolger, GE
Bob Tsai, Exelon Nuclear

Core and Fuel

- Equilibrium core analyzed to demonstrate reactivity margin and thermal margin capability
- Subsequent to EPU submittal reload core analysis performed for Reload 8 / Cycle 9

Clinton Cycle 9 Core Design BOC

AmerGen
An Exelon/British Energy Company



Bundle Name		IAT	# in Core	# Fresh	AvgWt KG	AvgExp GWD/ST	AvgRea	Avg Power
GE10-P8SXB353-12GZ-120T-150-T		11	168	0	177.93	25.0	1.010	0.590
GE14-P10SNAB353-13GZ-120T-150-T-2412		12	112	0	180.17	14.2	1.106	1.210
GE14-P10SNAB354-15GZ-120T-150-T-2413		13	76	0	179.83	13.3	1.106	1.270
GE14-P10SNAB395-16GZ-120T-150-T-2519		14	108	108	179.23	0.0	0.971	0.900
GE14-P10SNAB385-16GZ-120T-150-T-2520		15	160	160	179.18	0.0	0.960	1.220
		Total	624	268	179.11	10.9	1.019	1.00

CYCLE EXP	K-EFF	FLOW-%	MFLCPR	MFLPD	MAPRAT	AXIAL POWER PEAK
200	1.0017	100.0	.840(12, 7)	.854(10,11,16)	.886(10,11,16)	1.349(10)
800	1.0018	100.0	.841(12, 7)	.804(11,10,17)	.836(10,11,17)	1.359(10)
1400	1.0018	97.2	.848(12, 7)	.809(12, 7, 4)	.839(7,12, 4)	1.361(5)
2100	1.0016	94.1	.855(7,12)	.821(12, 7, 4)	.853(7,12, 4)	1.387(5)
2800	1.0018	91.6	.860(7,12)	.828(12, 7, 4)	.862(7,12, 4)	1.406(5)
3300	1.0018	92.9	.856(7,12)	.840(12, 7, 4)	.877(7,12, 4)	1.432(5)
4000	1.0016	92.3	.841(12,13)	.835(10,10, 5)	.835(10,10, 5)	1.385(5)
4700	1.0013	94.1	.818(9, 8)	.846(10,10, 5)	.863(9, 8, 4)	1.432(5)
5400	1.0006	94.7	.812(10, 7)	.854(10,10, 6)	.878(8, 8, 6)	1.478(5)
6100	0.9999	94.1	.821(10, 7)	.866(10,10, 6)	.900(8, 8, 6)*	1.544(5)
6800	0.9994	99.6	.863(13,14)	.856(10,10,19)	.822(14,14,17)	1.333(5)
7500	0.9992	96.1	.866(13,14)	.845(10,10,19)	.819(14,14, 5)	1.389(5)
8200	0.9983	93.5	.860(13,14)	.841(14,14, 4)	.853(8, 7, 4)	1.474(4)
8900	0.9978	91.1	.859(13,14)	.861(14,14, 4)	.875(8, 7, 4)	1.535(4)
9600	0.9968	95.7	.881(13,14)*	.808(14,14, 4)	.845(9, 6, 4)	1.358(4)
10300	0.9960	93.3	.873(13,14)	.794(5,13,19)	.822(9, 6, 4)	1.330(4)
11000	0.9954	93.5	.852(13,14)	.806(5,13,19)	.805(5,13,19)	1.279(5)
11500	0.9950	95.9	.829(13,14)	.815(5,13,19)	.817(5,13,19)	1.263(20)
12000	0.9945	99.3	.817(11, 6)	.821(5,13,19)	.826(5,13,19)	1.276(20)
12500	0.9940	94.8	.842(11, 6)	.855(3,13, 4)	.850(4,13, 4)	1.451(4)
13100	0.9940	100.0	.827(11, 6)	.788(3,13, 4)	.783(4,11, 4)	1.329(7)
13750	0.9931	100.0	.830(8, 7)	.805(10,10,10)	.754(9, 7, 8)	1.354(8)
14050	0.9928	100.0	.829(8, 7)	.796(10,10,11)	.753(10,14,10)	1.332(9)
14600	0.9928	100.0	.835(9, 8)	.870(10,10,10)*	.836(10,10,10)	1.355(9)
14900	0.9927	96.3	.840(9, 8)	.846(10,10,10)	.820(10,10,10)	1.308(10)
15100	0.9930	100.0	.827(9, 8)	.847(10,10,11)	.825(10,10,10)	1.309(10)
15200	0.9927	100.0	.841(14, 7)	.837(10,10,10)	.818(10,10,10)	1.331(10)
15300	0.9926	100.0	.842(14, 7)	.834(14,10,17)	.815(10,10,10)	1.323(10)
15550	0.9928	100.0	.841(14, 7)	.854(10,10,11)	.840(10,10,10)	1.352(10)

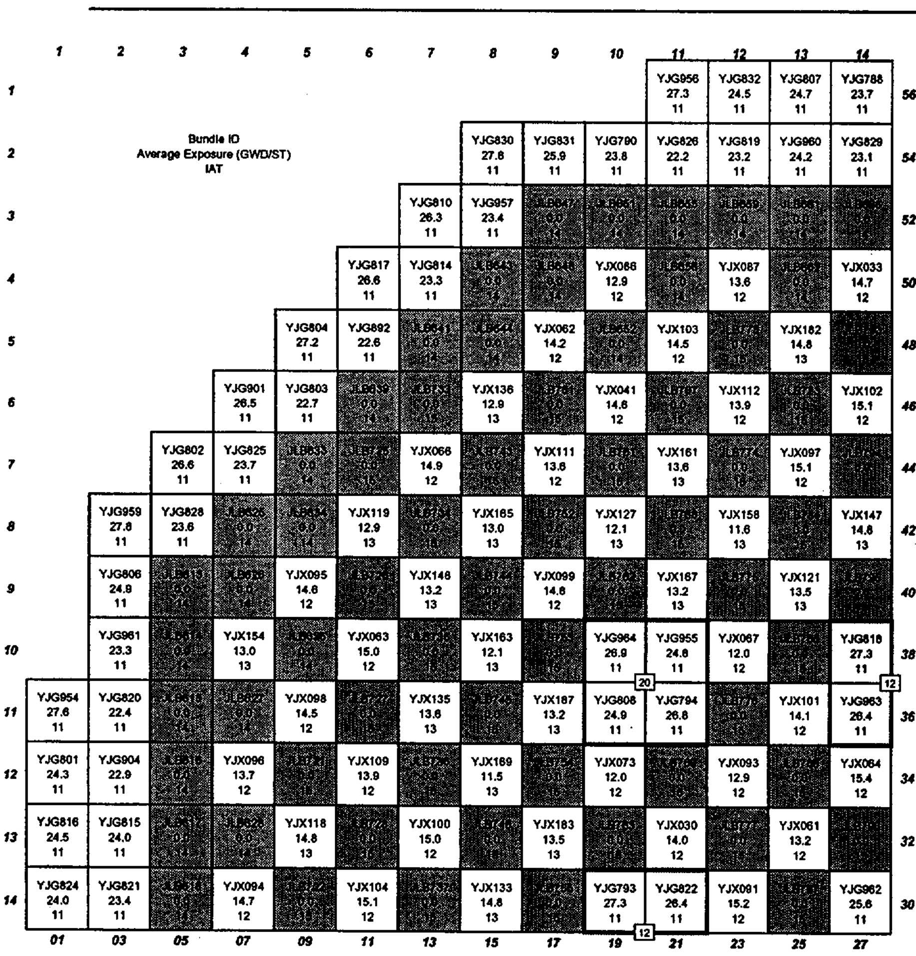
Provides the desired energy

Has adequate MCPR margin

Has adequate LHGR and MAPLHGR margin

Clinton Cycle 9 Core Design BOC at CRTP

AmerGen An Exelon/British Energy Company



Bundle Name		IAT	# In Core	# Fresh	AvgWt KG	AvgExp GWD/ST	AvgRea	Avg Power
GE10-P8SXB353-12GZ-120T-150-T		11	168	0	177.93	25.0	1.013	0.590
GE14-P10SNAB353-13GZ-120T-150-T-2412		12	112	0	180.17	14.2	1.109	1.210
GE14-P10SNAB354-15GZ-120T-150-T-2413		13	76	0	179.83	13.3	1.109	1.270
GE14-P10SNAB395-16GZ-120T-150-T-2519		14	108	108	179.23	0.0	0.972	0.900
GE14-P10SNAB385-16GZ-120T-150-T-2520		15	160	160	179.18	0.0	0.962	1.220
		Total	624	268	179.11	10.9	1.022	1.00

CYCLE EXP	K-EFF	FLOW-%	MFLCPR	MFLPD	MAPRAT	AXIAL POWER PEAK
200	1.0051	100.0	.804(12, 7)	.806(10,11,16)	.861(10,11,16)	1.364(10)
800	1.0051	100.0	.805(12, 7)	.757(11,10,17)	.810(10,11,17)	1.375(10)
1400	1.0051	97.2	.812(7,12)	.756(10,10,10)	.798(12, 7, 5)	1.368(10)
2100	1.0049	94.1	.818(7,12)	.753(12, 7, 4)	.806(12, 7, 5)	1.369(5)
2800	1.0051	91.6	.823(7,12)	.761(12, 7, 4)	.816(7,12, 4)	1.389(5)
3300	1.0051	92.9	.819(7,12)	.772(12, 7, 4)	.831(7,12, 4)	1.415(5)
4000	1.0049	92.3	.803(12,13)	.765(10,10, 6)	.795(10,10, 6)	1.364(5)
4700	1.0046	94.1	.783(9, 8)	.778(10,10, 5)	.816(9, 8, 4)	1.412(5)
5400	1.0040	94.7	.778(10, 7)	.793(10,10, 6)	.849(8, 8, 6)	1.459(5)
6100	1.0033	94.1	.787(10, 7)	.806(10,10, 6)	.873(8, 8, 6)*	1.530(5)
6800	1.0030	99.6	.824(13,14)	.804(10,10,19)	.796(14,14,17)	1.305(5)
7500	1.0029	96.1	.827(13,14)	.794(10,10,19)	.782(14,14,17)	1.365(5)
8200	1.0021	93.5	.820(13,14)	.763(14,14, 5)	.801(8, 7, 4)	1.439(5)
8900	1.0016	91.1	.818(13,14)	.784(14,14, 4)	.830(8, 7, 4)	1.498(4)
9600	1.0007	95.7	.837(13,14)*	.754(11,11,19)	.801(9, 6, 4)	1.340(5)
10300	0.9998	93.3	.827(13,14)	.747(5,13,19)	.786(9, 6, 4)	1.321(5)
11000	0.9990	93.5	.804(13,14)	.757(5,13,19)	.781(5,13,19)	1.274(5)
11500	0.9985	95.9	.787(11, 6)	.764(5,13,19)	.791(5,13,19)	1.271(20)
12000	0.9979	99.3	.781(11, 6)	.769(5,13,19)	.798(5,13,19)	1.284(20)
12500	0.9971	94.8	.802(11, 6)	.811(3,13, 4)*	.833(4,13, 4)	1.475(4)
13100	0.9969	100.0	.787(11, 6)	.747(3,13, 4)	.764(4,11, 4)	1.322(4)
13750	0.9959	100.0	.791(8, 7)	.675(10,14,10)	.725(4,11, 4)	1.341(8)
14050	0.9954	100.0	.789(8, 7)	.731(10,10,11)	.711(10,14,10)	1.317(9)
14600	0.9952	100.0	.794(9, 8)	.799(10,10,10)	.792(10,10,10)	1.337(9)
14900	0.9950	96.3	.799(9, 8)	.778(10,10,11)	.776(10,10,10)	1.294(10)
15100	0.9954	100.0	.787(9, 8)	.781(10,10,11)	.783(10,10,11)	1.295(10)
15200	0.9950	100.0	.799(14, 7)	.769(10,10,11)	.773(10,10,10)	1.316(10)
15300	0.9949	100.0	.800(14, 7)	.766(14,10,17)	.772(10,10,11)	1.307(10)
15550	0.9950	100.0	.799(14, 7)	.787(10,10,11)	.798(10,10,11)	1.338(11)

Has about 5% more MCPR margin

Has about 5% more LHGR and MAPLHGR margin

Core and Fuel

- Adequate margins demonstrated in equilibrium design and in cycle 9 core design

Containment Analysis

Eric Schweitzer, AmerGen
Dan Pappone, GE

Containment Analysis

- Followed the established method for containment analysis in ELTR1
- Limiting events analyzed
  - Main steam line break (MSLB)
  - Recirculation suction line break (RSLB)
  - Alternate shutdown cooling (ASDC)

Containment Analysis

Containment Performance Results

Parameter	USAR Methods (102% of OLTP)	Current Methods (102% of OLTP)	Current Methods 102% of EPU	Design Limit
Peak Drywell Pressure (psig)				
MSLB	18.9	23.1	23.2	30
RSLB	19.7		21.3	
Peak Drywell Atmos Temp. (°F)				
MSLB	330	339.9*	340.0*	330
RSLB	246.6		248.6	
Peak Containment Pressure (psig)				
MSLB	8.7		7.0	15
RSLB	8.7	3.2	3.9	
ASDC			6.1	
Peak Containment Temp. (°F)				
MSLB	180.3		158.8	185
RSLB	180.3	149.2	149.3	
Peak Suppression Pool Bulk Temp. (°F)				
MSLB	180.3		177.1	185
RSLB	180.3	167.5	177.2	
ASDC	175.5		182.6	

* This temperature represents an instantaneous peak of <0.5 seconds at the beginning of the event.

Exceptions to ELTR 1/2 Requirements

Eric Schweitzer, AmerGen

Kent Scott, AmerGen

ECCS Performance

ECCS Performance

Results

Parameter	USAR	EPU	Limit
Method	SAFER/GESTR	SAFER/GESTR	NA
Power (MWt)	3015	3543	NA
Licensing Basis Peak Clad Temperature (PCT), °F	< 1550	< 1570	≤ 2200
Cladding Oxidation, % Original Clad Thickness	< 1.0	< 1.0	≤ 17
Hydrogen Generation (Corewide Metal-Water Reaction), %	< 0.1	< 0.1	≤ 1.0

Transient Events

Transient Events
Results

Limiting Event	Cycle 8	Cycle 9	Limit
Overpressurization (Vessel Pressure)	1288 psig	1314 psig	1375 psig
Turbine Trip without Bypass (OLMCPR)	1.34	1.31	NA

Stability

Stability

- CPS is currently operating under interim corrective actions (ICAs)
  - ICAs provide manual prevention and suppression
- CPS implementing stability solution Option III following resolution of pending 10 CFR 21 issue
  - CPS EPU startup under ICAs
- ICA boundaries unchanged in terms of absolute power and flow conditions for EPU
  - Operator actions remain unchanged
  - Start up path unaffected

Large Transient Testing

- ELTR1 specified large transient tests
  - MSIV closure of all valves for uprates > 110 % Original Licensed Thermal Power (OLTP)
  - Generator load rejection for uprates > 115 % OLTP
- AmerGen took exception to these tests as an unnecessary challenge to the plant
- GE has concluded these tests are no longer necessary when reactor dome pressure is unchanged

Large Transient Testing

- Performance of plant structures, systems and components has been evaluated at EPU conditions
- Plant components will perform as designed
- Surveillance testing will confirm that these components maintain required performance capability
- There is operating experience on uprated plants
- Transient modeling code shown to be acceptable
- Plant response to these transients as a result of EPU will not change significantly

ATWS Event Response

Kent Scott, AmerGen
Fran Bolger, GE

ATWS Event Response

- EPU ATWS event response operator actions unchanged from pre-EPU conditions
  - Following reactor recirculation pump trip the reactor power and flow is unchanged
  - Symptomatic conditions for ATWS remain unchanged for EPU
  - Mitigating operator actions remain unchanged for control of reactor power, water level, and pressure

ATWS Event Response

- Raised minimum SLC boron concentration to increase the rate of negative reactivity addition
- Analytical results for EPU ATWS

	Pre-EPU	EPU	Limit
Peak Reactor Pressure (psig)	1264	1336	1500
Peak Suppression Pool Temperature (°F)	160	165	185
Peak Containment Pressure (psig)	5.6	6.3	15
Peak Clad Temperature (°F)	1440	1477	2200

Flow Accelerated Corrosion

Harold Crockett, Exelon Nuclear

Flow Accelerated Corrosion

- FAC program has been updated for EPU parameters
- CHECWORKS model predicted most significant wear increase on scavenging steam line
  - Predicted wear change from 38mils/year pre-EPU to 70 mils/year post-EPU
  - ≤20 mils/year wear measured pre-EPU
  - Model will be calibrated with post-EPU measurements
  - Expected changes in predicted wear rates
- Subject line scheduled for replacement C1R10
- Programmatic controls ensure that inspections continue and extent of condition is assessed for unanticipated results

EPU Risk Evaluation

Bill Burchill, Exelon Nuclear

FPIE Risk Evaluation

Dominant PRA Model Changes to Represent EPU

PRA Technical Element	PRA Model Change	Contribution to CDF Increase
Op. Fails to Initiate ADS	Time available decreases 13%	3%
Op. Fails to Restart FW Given Op Fails to Initiate RPV Depressurization	Dependent HEP increases based on change in RPV Depressurization HEP	1.6%
Op. Fails to Initiate SLC Injection (early) During ATWS (2 SLC pumps)	Time available decreases 25%	1.1%
Op. Fails to Initiate SLC Injection (early) During ATWS (1 SLC pump)	Time available decreases 33%	0.4%
Op. Fails to Manually Start an EDG if Auto Start Fails	Time available decreases 13%	<0.1%
Op. Fails to Bypass MSIV Isolation to Maintain Steam Path	Time available decrease 13%	<0.1%

AmerGen
An Exelon/British Energy Company

FPIE Risk Evaluation
Results

- Pre-EPU PRA results

CDF (yr^{-1})	LERF (yr^{-1})
1.4E-5	1.4E-7

- EPU has small impact on CDF and LERF
  - CDF (+6%)
  - LERF (+6%)
- Risk changes conform to Regulatory Guide 1.174 Guidelines
  - ΔCDF is in Region III (very small risk change)
  - ΔLERF is in Region III (very small risk change)

Qualitative Risk Evaluation

- Reviewed EPU impact on other risk sources
  - Fire
  - Seismic
  - shutdown
- EPU impact is negligible

Summary of EPU Risk Impact

- Risk impact was evaluated using standard PRA methods (quantitative and qualitative)
- Quantified risk impact is a small percentage of current plant risk
- ΔCDF is a very small risk change per Regulatory Guide 1.174
- ΔLERF is a very small risk change per Regulatory Guide 1.174
- Risk impacts from external events and shutdown conditions are negligible

Project Implementation

Kent Scott, AmerGen
CPS Operations Services Manager

Project Implementation

Training

- Classroom material presented thorough review of EPU changes and uprate operating experience
- Simulator training
  - EPU full power conditions
  - Normal operations scenarios
  - Dynamic transients and accidents scenarios selected to highlight both similarities and differences in plant response at EPU and current power levels

Project Implementation

Start-up Test Overview

- Careful and deliberate approach to uprated power levels
- Incorporate Exelon uprate testing experience
- Steady state data collection and testing beginning at 90% of OLTP
- 2% incremental power test program
- Power increases along constant rod line to maximum achievable power level

Project Implementation

Start-up Test Overview

- Dynamic testing begins at approximately 70% OLTP
  - Pressure control system
  - Feedwater level control system
  - Turbine valve surveillances

Conclusion

Terry Simpkin, Exelon Nuclear
Licensing Manager

Conclusion

- Extensive analyses using accepted methodology
- No significant impacts on plant response or system integrity
- Minimal changes in plant risk
- Plant operation is acceptable at EPU conditions

Advisory Committee on Reactor Safeguards Meeting

Review of ANO-2 Core Power Uprate Request

March 7, 2002

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Introduction

Craig Anderson
Vice President Operations

Entergy

Introduction

Presenters (Entergy)

Craig Anderson
Bryan Daiber
Dale James
Rich Swanson
Joe Kowalewski

Entergy Support Staff

Doyle Adams
Glenn Ashley
Vince Bond
Dennis Boyd
Sherrie Cotton
Milton Huff
Mike Krupa
Mike Lloyd
Jim McWilliams
Tommy Morrison
Roger Wilson

Westinghouse (CE) Support Staff

Jeff Brown
Joe Cleary
Mehran Golbabai
Mike Krammen

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Introduction

- Analyses and modifications performed to support safe uprate
- Adequate operating / design margins have been maintained
  - NSSS operating limits bounded by other C-E plants
- Accepted methodologies utilized
- Compliance with applicable regulations/safety limits has been demonstrated

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Introduction

- Project Overview
  - 7.5% uprate
  - Majority of plant modifications to support uprate have already been completed
  - Implementation spring 2002 (refueling outage 2R15)
  - ANO is prepared for uprate

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Plant Changes to Accommodate Power Uprate

Bryan Daiber
Safety Analysis Engineer

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Plant Modifications

- Site Modification Approach
  - Modifications implemented over four cycles
  - All modifications accommodate 7.5% power uprate conditions
  - Early implementation of modifications provided validation of performance prior to uprate
  - Majority of major modifications are installed

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Plant Modifications

Plant Changes / Modifications- Installed to date	**Plant Changes / Modifications- Before power uprate (Cycle 16)**
Replacement steam generators	Fuel (Erbia burnable poison)
Containment uprate	Stator water cooler (> surface area)
Condenser replacement (larger, copper removed)	Isophase bus cooling fans (> flow)
Moisture separator reheaters (copper removed)	Re-rating 3rd & 4th feedwater heaters (Code issue)
HP turbine replaced (> efficiency)	Setpoint changes
LP turbines - 4 stages (> efficiency)	
Generator rewind (> MVA)	
Hydrogen coolers (> surface area)	
Stator water cooler piping rerouted (lower inlet temp)	
Containment cooling fan pitch change	
Containment chilled water coils replaced (> normal cooling)	

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Plant Modifications

- Replacement Steam Generators (RSGs)

Parameter	**Original SGs (OSGs)**	**Replacement SGs (RSGs)**
Tube sheet diameter (inches)	166	170
Tube material	Alloy 600	Alloy 690 TT
Number of tubes	8,411	10,637
Tube outside diameter (inches)	3/4	11/16
Surface area (ft^2)	86,559	108,700 (+25%)
Secondary side mass (lbs)	138,200	165,000
Primary side volume (ft^3)	1600	1839
Integral flow restricting nozzle	no	yes

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Plant Modifications

- Containment Uprate
  - uprated from 54 to 59 psig
  - similar to ANO-1 (always 59 psig design)
  - comprehensive finite element analysis
  - utilized tendons previously not credited
  - evaluated all systems, structures and components inside containment
  - license amendment 225

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Plant Modifications

- Fuel Design
  - Change in Integral Burnable Absorber
    - currently using Gadolinia
    - Cycle 16 will use Erbia
  - Benefits of Erbia
    - More dilute poison, more evenly distributed
    - Less adverse response to transients (Control Element Assembly withdrawal events)
    - Better moderator temperature coefficient control
    - Better power peaking

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Plant Modifications

- Comparison to Previous Cycles

Parameter	Cycle 14	Cycle 15	Cycle 16
Burnable Poison	Gadolinia	Gadolinia	Erbia
Reload Batch Size, #	80	68	80
Cycle Length, EFPD	557	491	485 (521*)
Radial Peaking Factor, Fr	1.56	1.56	1.44
Fuel Zoning	3	3	2
Cycle Burnup, MWD/T	19,770	17,899	18,825
Batch Discharge Burnup, MWD/T	44,864	45,127	42,923

* effective cycle length adjusted for 2815 MWt

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Compliance with Regulatory Requirements

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Plant Margins

- Review of overall plant design
  - Balance of Plant
  - Nuclear Steam Supply System
  - Control systems
  - RSGs, containment and fuel design
- Implemented modifications as necessary to restore margin
- NSSS operating limits bounded by other CE plants

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Plant Margins

- RSGs
- Containment
  - Increased design pressure from 54 psig to 59 psig
  - Integral flow restrictor nozzle
  - Installed Containment Spray Actuation Signal (CSAS) to isolate feedwater and steam
  - changed TS to be more conservative - 2 fans
- Fuel Design
  - Erbia Poison

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ECCS Analysis

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ECCS Analysis

- Methodology
  - LBLOCA
    - New approved methodology applied
    - 1999 EM (evaluation model)
    - CENPD-132, Supplement 4-P, Revision 1,
  - SBLOCA
    - Used current Analysis of Record methodology
    - S2M
    - CENPD-137, Supplement 2-P-A

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ECCS Analysis

- Results

Parameter	Criterion	LBLOCA	SBLOCA
Break Size		0.4 DEG/PD	0.04 ft^2/PD
Peak Clad Temp, °F	$\leq$ 2200	2154	2090
Max Clad Oxidation, %	$\leq$ 17	7.8	12.5
Max Core Wide, Oxidation %	$\leq$ 1	< 0.99	< 0.73
Coolable Geometry	Yes	Yes	Yes

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Review Issues

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ATWS

- ATWS Event Response for Uprate Conditions
  - ANO-2 complies with 10CFR50.62 (ATWS rule) with its Diverse Scram System / Diverse Turbine Trip (DSS / DTT) and Diverse Emergency Feedwater Actuation System (DEFAS)
  - Power uprate did not affect system design functions (hardware, operator interface, system logic, etc.)
- Existing Setpoints and Response Times were Maintained for Uprate

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Impact on Containment Response

Overview

- NRC Approved Methods Used
  - Westinghouse - CE Mass/Energy release
  - Bechtel COPATTA code used for containment response
- Results Bounding For Power Uprate
- License Amendment 225

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Impact on Containment Response

Results

- Limiting Single Failure
  - For LOCA - Loss of EDG
  - For MSLB - 0% Power, 1 CS Train Failure
- Limiting Containment Peak Pressure
  - 57.6 psig (LOCA)
  - 57.4 psig (MSLB)
- Minimum Containment Pressure
  - 27 psig

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Alloy 600

Dale James

Manager Engineering Programs

Entergy

Alloy 600

- Reactor Vessel Head Nozzles
  - Preliminary Safety Evaluation performed per Materials Reliability Program (MRP) program document - EPRI MRP Reports 44 and 48
  - Ranking time reduced from 17.1 EFPY to 14.2 EFPY (t = 0 measured from March 2001)
  - Still within moderate category
  - 100% volumetric non-destructive exam planned for 2R15
- Hot Leg Small Bore Nozzles
  - Continue bare metal visual exams each refueling

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Flow Accelerated Corrosion

- Evaluation of power uprate conditions indicate minimal impact on FAC wear rates
- Monitoring and replacement activities will continue to assure potential for FAC failures are minimized

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Operator Training/Impact

Rich Swanson
Operations

Entergy

Operator Training/Impact

- Training
  - Simulator changes have been made
  - Two training cycles
  - Crews evaluated on the uprated plant prior to outage
- Changes have much less impact than SG Replacement

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Operator Training/Impact

- Controls and Displays
  - Changes minimal or none
    - No physical modifications to control stations
    - No change to format of the Safety Parameter Display System

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Operator Training/Impact

- Procedures
  - Emergency, Abnormal and Normal Operating
  - No change to type and scope
  - No new procedures
- Emergency Operating Procedures
  - No change to type and nature of actions
  - No new actions

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Operator Training/Impact

- Power Ascension Testing
  - Operations involved in development and implementation
  - Test teams designated to perform testing
  - Experienced

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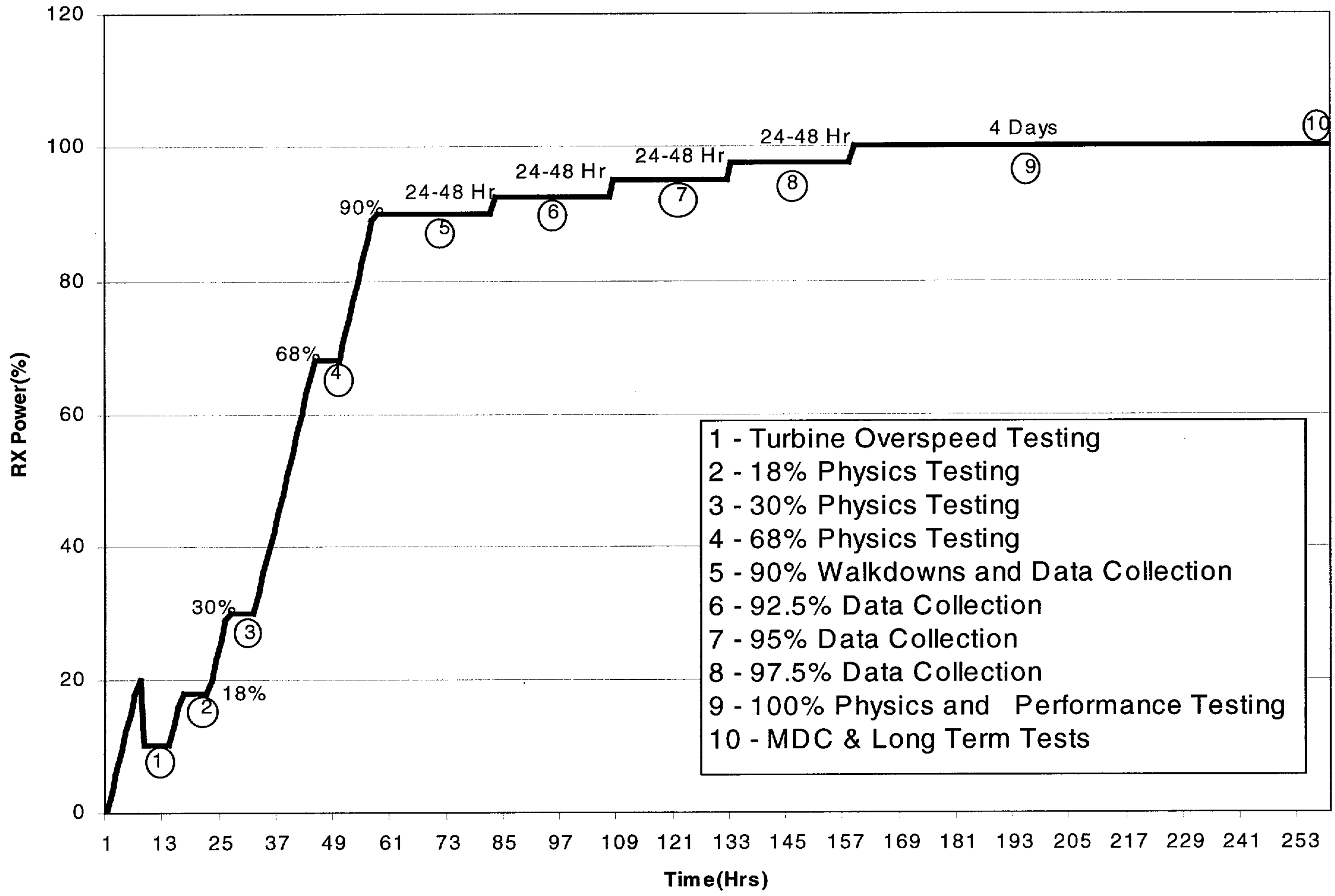
2R15/Cycle 16 Power Ascension Profile
(estimate only)



Startup Testing Program

Joe Kowalewski
Director Engineering

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Startup Testing Program

Program Basis

- Reviewed against original startup testing program in Chapter 14 of Final Safety Analysis Report
  (Regulatory Guide 1.68)
- Scope of modifications for RSG/Power Uprate
- Industry experience
  - reviewed startup test programs for most recent CE System 80 plants
  - reviewed startup test programs for other SG replacements and power uprates
  - conducted self-assessment of our startup testing program

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Startup Testing Program

Program Scope

- Extensive startup testing for steam generator replacement and power uprate modifications previously performed

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Startup Testing Program

- Shutdown to 2R15
  - Unit load transient (~25% load rejection) to verify integrated control system response
- 2R15 Outage
  - Routine pre-criticality, low power physics, and power range testing to verify core design and plant functionality

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Startup Testing Program

- Control of 2R15 Power Ascension
  - Overall controlling work plan
  - Power ascension from 90% & above plateaus will be approved by the Test Working Group (TWG)
    - TWG made up of senior ANO plant management and experienced testing personnel
    - TWG will review test results and resolution of any significant testing deficiencies prior to the continuation of power ascension

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Startup Testing Program

- Cycle 16 Power Range Testing
  - Power uprate data collection/design prediction test
    - Verify heat balance meets design predictions
    - Collection and evaluation of key plant parameters during steady state conditions
  - Biological shield surveys
  - Piping vibration testing inside & outside containment

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Startup Testing Program

- Cycle 16 Power Range Testing (cont'd)
  - RSG moisture carryover test
  - RSG performance test

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ANO-2 Power Uprate Risk Impact Assessment

Bryan Daiber

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Impact on Internal CDF

- Initiating events & frequencies
- Success criteria
- Component failure rates
- System fault tree analysis
- Operator responses

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Operator Responses

- Reviewed the operator actions
- CENTS used to quantify the effect of uprate (available time for operator action)
- Incorporated new times into the human reliability analysis (HRA) models

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Level 1 CDF Quantification

- Quantified pre and post uprate models
- Change in CDF (2.7 E-6, 16%)
  - pre 1.70 E-5 /rx-yr
  - post 1.97 E-5 /rx-yr
- Within Region II (small changes)
  Regulatory Guide 1.174

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LERF

- Change in LERF (9.3 E-8, 24%)
  - pre 3.87 E-7 /rx-yr
  - post 4.80 E-7 /rx-yr
- Within Region III (very small changes)
  Regulatory Guide 1.174

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Evaluation of Other PSA Elements

No unique or significant insights gained on:

- IPEEE Internal Fire Analysis
- IPEEE Seismic Analysis
- IPEEE Other External Events Analysis
- Shutdown Risk

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Concluding Remarks

Craig Anderson

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