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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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510th FULL COMMITTEE MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY,

MARCH 4, 2004

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ROCKVILLE, MARYLAND

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The Advisory Committee met at 8:30 a.m. at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, MARIO V. BONACA, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA	Chairman
GRAHAM B. WALLIS	Vice-Chairman
STEPHEN L. ROSEN	At-Large
GEORGE E. APOSTOLAKIS	Member
F. PETER FORD	Member
THOMAS S. KRESS	Member
GRAHAM L. LEITCH	Member
DANA POWERS	Member

COMMITTEE MEMBERS: (cont.)

VICTOR R. RANSOM Member

WILLIAM J. SHACK Member

JOHN D. SIEBER Member

ACRS STAFF PRESENT:

RALPH ARCHITZAL

RAJ AULUCK

STEVE BAJOREK

STEVE BLOOM

KEN CHANG

JOESEPH COLACCINO

KIMBERLEY CORP

ANDRE DRUZO

BARRY J. ELLIOT

GEORGE GEORGIEV

FRANK GILLESPIE

JIN-SIEN GUO

MICHELLE HART

M. HARTZMAN

JOHN HONCHARIK

Y. GENE HSII

NAEEM IQBAL

DAVID JENG

WALTON JENSEN

STEVEN JONES

ACRS STAFF PRESENT: (cont.)

P. T. KUO
CAROLYN LAURON
ARNOLD LEE
SAM LEE
Y. C. LI
TILDA LIU
LAMBROS LOIS
JIM LYONS
JOHN S. MA
RICHARD McNALLY
JIM MEDOFF
SAM MIRANDA
S. K. MITRA
DUC NGUYEN
BOB PALLA
LAUREN QUINORES-NAVARRO
J. H. RAVAL
NICK SALTOS
JOHN SEGALA
PAUL SHEMANSKI
JAELLE STAREFOS
JIM STRUNISHA
RAM SUBBARATNAM
SUMMER B. SUN

ACRS STAFF PRESENT: (cont.)

EDWARD THROM

JOHN TSAO

JENNIFER UHLE

LEN WARD

STEVE WEST

JERRY WILSON

CHENG-IH (JOHN) WU

I-N-D-E-X

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

(8:29 a.m.)

3) OPENING REMARKS BY THE ACRS CHAIRMAN

3.1) OPENING STATEMENT

CHAIRMAN BONACA: Good morning. This meeting will now come to order. This is the second day of the 510th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting, the Committee will consider the following: license renewal application for the H. B. Robinson steam electric plant, Unit 2; interim review of the AP1000 design; license renewal application for the Virgil C. Summer nuclear station; proposed criteria for ACRS evaluation of the effectiveness (quality) of the NRC safety research programs; preparation of ACRS reports.

A portion of this meeting may be closed to discuss Westinghouse proprietary information applicable to the AP1000 design. This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John Larkins is the designated federal official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions. A transcript of portions of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

3.2) ITEMS OF CURRENT INTEREST

CHAIRMAN BONACA: Before we start with the presentation of the agenda, I would like to point your attention to items of interest. You have a package in front of you. There are a number of interesting papers. There is also information about operating events and inside NRC articles and fact sheets.

With that, if there are not any comments from members of the Committee, then I will move on to the license renewal application for the Robinson steam electric plant, Unit 2. And Mr. Leitch will take us through that presentation.

MEMBER LEITCH: Okay. Thank you, Dr. Bonaca.

4) LICENSE RENEWAL APPLICATION FOR THE

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2

4.1) REMARKS BY THE SUBCOMMITTEE CHAIRMAN

MEMBER LEITCH: We are here today to hear presentations from the staff and the licensee regarding the license renewal application for the H. B. Robinson steam electric plant, Unit 2.

It is a 2,339-megawatt thermal Westinghouse three-loop pressurized water reactor. It shares a site with an older fossil unit, hence the name Unit 2 because the fossil unit is called Unit 1. So this is the only nuclear unit on that site and sometimes is also referred to as Robinson nuclear plant.

We did have a subcommittee meeting, as you recall. Many of you attended that subcommittee meeting on September 30th of 2003. At the time of that subcommittee, we reviewed the draft safety evaluation report. At that point, there were two open items and a number of confirmatory items.

We heard tentative plans for the closure of those items at the subcommittee meeting, but formal closure had yet to be achieved. In the meantime, we are going to hear today about the formal closure of those items and both those open items and confirmatory items.

So, with those words of introduction, I will turn it over to P. T. Kuo, who will lead us through this presentation. P. T.?

MR. KUO: Yes. Thank you, Dr. Leitch, and good morning.

4.2) BRIEFING BY AND DISCUSSIONS WITH REPRESENTATIVES OF THE NRC STAFF AND CAROLINA POWER AND LIGHT

MR. KUO: My name is P. T. Kuo, the Program Director for the License Renewal and Environmental Impacts Program. On my right is Dr. Sampson Lee, who is the Section Chief of the License Renewal Section A. And on my far right is S. K. Mitra, who is the Project Manager for the Safety Evaluation of H. B. Robinson project.

S. K. Mitra will be making the staff presentation today with assistance from the tech staff, the tech staff from the Division of Engineering, Division of System Safety and Analysis, and the Inspection Program.

We also have the original inspector, Caudle Julian, joining us on the telephone line in case you may have any questions about the inspections conducted throughout the review time.

With that, I would like to turn it over the presentation first to the applicant, and then the staff presentation will follow. If there are any questions, I will be glad to answer at this time.

MR. STEWART: Good morning. I'm Roger

Stewart, and I'm going to talk to you about the Robinson license renewal.

I would like to start by introducing you a little bit to the Robinson plant. As Dr. Leitch indicated, it is also known as Unit 1. This is the Unit 1 plant. Unit 2 is the nuclear plant.

Robinson has some unique features about it. One feature that is particularly unique is our containment. Our containment has grouted timmets. So we do not have timmet galleries that is typical of the other applications you review.

Another feature on our containment is the containment liner is insulated on the inside. And that is part of our licensing basis to limit the heat transfer during a postulated design basis accident.

VICE-CHAIRMAN WALLIS: What is this insulation made of?

MR. STEWART: It's some version of a poly plastic. I don't remember the exact composition. It's attached. We have a steel liner inside the containment. It's attached to the steel liner. There's a stainless steel sheeting on the outside of it.

VICE-CHAIRMAN WALLIS: So it is covered with the sheeting?

MR. STEWART: Yes, sir.

VICE-CHAIRMAN WALLIS: It is not exposed?

MR. STEWART: And it basically covers the cylindrical portion of the containment. The element does not insulate itself. It does have a stainless steel sheeting.

One other feature that is somewhat unique on Robinson, not totally unique, is all of our emergency power supplies 480-volt versus your typical 4,160. We also have a dedicated shutdown diesel right here. This is in addition to two emergency diesels.

As you can see with the units here, here is the security fit. So Unit 1 is right adjacent. There are some slight shared facilities, which we discussed in the subcommittees. So I won't go over those again.

MEMBER ROSEN: That dedicated shutdown diesel is just sitting on a pad out there? They're building around it?

MR. STEWART: Actually, if you can envision, it was brought in as a railroad car. It is basically a skid unit, self-contained. And there is a building around it. It is sitting on the pad. But basically we took the wheels off of it and permanently attached it.

MEMBER ROSEN: You say it is in a building, but you show --

MR. STEWART: I'm sorry. It's right here. You can see the exhaust stack. It is a shelter, if you will.

MEMBER ROSEN: But it's not a concrete or any other kind of building?

MR. STEWART: No, sir, it is not. It's right here.

Other questions?

(No response.)

MR. STEWART: Okay. I've covered the unique features. What I would like to do next is talk about what we have done in terms of major equipment, replacements, or upgrade. Within the past 20 years, we have replaced the steam generators.

Those were replaced in 1984. And to our last outage, which was November of 2002, we have 19 tubes plugged. We have no active degradation mechanisms. So we have had good results with our replacement steam generators.

MEMBER ROSEN: What is the material of construction of the tubes?

MR. STEWART: It's thermally annealed 690. I thought it was 690, but it's thermally annealed inconel. Do you remember? Six hundred? Thermally treated, yes, sir.

We have done some extensive replacement of the service water piping. First, we replaced all of the service water piping inside containment. We did that in 1988. And then on the discharge and inlet side of containment, we replaced that in 1990.

And we also replaced underground supply headers. We have a north header and a south header. And we replaced the north header in 1999. We had done some construction work. We added a rad waste building. And during the construction work, they had excavated close to the pipe. It had damaged the coating. So we were having some problems with pinhole-type leaks. So we ended up replacing that header.

On the turbine rotor, we replaced it. We did the low-pressure portion of the turbine in 1987. And then in 2002, we replaced the high-pressure portion. The high pressure was replaced as part of the power uprate here that we did in 2002. This was an Appendix K power uprate, and we raised the output by approximately two percent. We have no current plans for any additional power uprates on Robinson.

MEMBER LEITCH: Was the service water

piping replaced in kind?

MR. STEWART: No, sir. What we had is when we did the steam generator replacement in 1984, we learned what not to do in later practices. And we had a problem with microbiological induced corrosion. Ours was very specific. We had stainless steel pipe.

And the mic that we had attacked the heat-effective zone of the weld. It didn't do the weld. It didn't do the pipe. It took the heat-effective zone. And we replaced it with AL6X, which we have had very good luck with so far.

MEMBER LEITCH: Thank you.

MR. STEWART: In terms of ongoing or planned replacement, we're still completing our security upgrades. We will have those completed this year.

We have a replacement head on order. In fact, it is in fabrication now. They have finished the rough machining. And we expect to install that in refueling outage 23, which will be Fall of 2005.

When we talked to you on the subcommittee, we had a relief request related to the head inspection. We have since withdrawn that request. And we will conduct full inspection in this upcoming refueling outage.

We are also expanding our dry fuel storage. That project has just started basically this year. And we are expecting to load the first module on that in the third quarter of 2005.

MEMBER LEITCH: When you say you are "expanding" it, is there dry fuel storage on site now?

MR. STEWART: Yes, sir. In fact, we signed out an application for renewal of that facility last week. Its license expires 2005 or --

MR. CLEMENTS: Two thousand six.

MR. STEWART: Two thousand six. So we just submitted a renewal for that one. We are also looking to do some work on our generator and excitor and refurbish those. And that is planned toward refueling outage 24, which would be in 2004. Those are the major projects that we have.

I would like to go over a little bit of the operating experience. In 2003, Robinson had a very good year. Our capacity factor was 103.54 percent with power uprate. It was basically a record generation year for Robinson. We did have a refueling outage that year. And basically this morning we have a continuous run of 465 days.

One thing I will point out to you is in 2003, our exposure -- and this is the total dose for operating the plant for the year -- was 4.8 REM for the year. To go along with that, we had 25 zero-dose days in 2003. And we have had four so far in 2004.

When I checked with RFC Tuesday, we had one step-off pad in the plant. That is in the hot machine shop to support some work on some contaminated equipment we're doing outside of the power block.

MEMBER LEITCH: I am a little confused by the capacity factors greater than 100. Is that on the basis of power uprate? In other words, that is on the original basis?

MR. STEWART: No, sir. If you go back to this year, this was a non-outage year. The capacity factor is based on a theoretical maximum when we look at our cooling temperature, what we expect for highest cooling temperature.

So if you go into some of the hotter days and stuff, it drops down a bit because we have a lake. And Unit 1 and Unit 2 share the lack. So our lack temperatures tend to go up in the summer, and the factors go down.

So if we have relatively minor weather, we can get a better vacuum. We can get a better capacity factor.

MEMBER LEITCH: But, now, you did uprate, did you not, based on improved feedwater?

MR. STEWART: Yes, sir, we did. We changed the MBC of the plant based on the power uprate.

MEMBER LEITCH: Now, there are some people beginning to experience problems with that ultrasonic flow measurement. There have been some recent reports about a couple of plants that suspect that they have been overpowered for some period of time. Are you familiar with that experience?

MR. STEWART: I am not familiar with that. We have had problems with ours on the welds and leaking at some of the sensors. In fact, we are doing a repair this outage to correct some of those welds.

We have had some problems with it leakage-wise, but what happens whenever we get the leak, it will tend to shut that down. It drives it to conservative mode. So we haven't seen as much power in all cases as we could because we have had to drop down a couple of percent based on problems with it, but we haven't seen anything calametric-wise that would drive it there.

MEMBER LEITCH: I am just surprised that you are getting numbers as high as 103.5 percent. You know, 101 perhaps wouldn't surprise me, but 103 is.

MR. CLEMENTS: Those are really based on historical MBC, which is substantially less than the plant is allowed. And it is based on electric generation obviously and not thermal generation. So the plant is just basically running and better maintained than it originally was.

MEMBER LEITCH: Okay. Thank you.

MR. STEWART: In 2004, we have a refueling outage coming up. It basically starts. It is planned for April 20th. The current plan has that as a 28-day outage. If you look at it, basically the plant's operated very well. We have had minimal time offline. And all the NRC performance indicators are green on the plant.

When Region II did their inspections, they looked at our boric acid corrosion program. They had made a couple of comments and expressed some concerns. The subcommittee asked us to follow up and explain what we have done with the boric acid program. We had plans for work when we talked in September.

Since September, we have implemented a corporate boric acid control program that is basically in effect for all three of our PWRs. It has got some specific guidance that requires all plant personnel recognize borated system leakage, understand its significance, and initiate corrective action when they detect the residue. That goes further to point out so that everyone understands that carbon and low-alloy steel components are exposed to boric acid components shall be carefully cleaned and inspected.

To go along with that, we have a Robinson plant-specific procedure that is a system walk-down procedure. We have since revised it to include similar statements that basically ask if any of the system engineers see any boric acid anywhere in the plant during their walk-down. So they basically initiate the work request or condition report that it get taken care of.

The concern, as I recall it, from Region II's aspect is the only mention of boric acid in this system walk-down procedure was mentioned as a potential radiological hazard. So we have since changed that.

CHAIRMAN BONACA: This statement is somewhat inconsistent with the previous slide that you had.

MR. STEWART: I'm sorry?

CHAIRMAN BONACA: This statement is somewhat inconsistent with the previous slide that you had if you are going to show it. Go back one slide?

It says, "If carbon and non-alloy steel components are exposed to boric acid, the components shall be inspected."

It seems to me that if you detect boric acid, you have a leak out there somewhere. I think that you may want to inspect the component, but you should have an action to -- well, you do have an action in the next statement to evaluate the conditions. So I am just trying to understand why you yourself do carbon and non-alloy steel components.

MR. STEWART: We also have a requirement to look for leakage, but the main thing we wanted to do is make sure that people were a little more tuned in. If you see boric acid, you need to do something with it.

It is part of the standard procedure when we go in and we are doing a cleanup. They try to find the source of the leak as well as clean up after it. That has typically been standard practice for a while. It just was not really documented in the procedures.

For Robinson license renewal, we credited 47 programs. Of those 47 programs, 10 were existing programs and required no changes. That leaves 37 commitments for 27 enhancements in 2 new programs. All of these commitments have been entered into the

Robinson commitment tracking system.

MEMBER APOSTOLAKIS: When does your current license expire?

MR. STEWART: It expires July 31st, 2010.

MEMBER APOSTOLAKIS: Thank you.

MR. STEWART: And what we plan to do with these commitments, if you will recall, the follow-up, the third inspection that Region II did, they came back and looked at the commitments in our commitment track. We have a transition plan in place that basically plans on moving these commitments from the license renewal organization to the plant organization if we don't have it implemented.

Where we stand on that relative to these 37 commitments as of today, a lot of them have already been implemented. We have made the enhancements to the procedures, and we have already done them. Eleven of them have been transitioned to the plant organization. They are actually in. They haven't so far belonged to the engineering group on site.

At Robinson, the way we do the commitments is the Robinson supervisor of licensing regulatory programs has overall responsibility for management of the commitment tracking. So the commitments may be assigned to individual organizations to implement, but one person is in charge of all tracking. So that if the NRC or anybody comes in and wants to know what is the status of the commitments, they go to that person in regulatory affairs so that they can run it down for them.

CHAIRMAN BONACA: When you do implement the enhancement, does the enhancement go into effect shortly after some date or are you waiting for 2010 to have that go into effect? How do you manage that transition?

MR. STEWART: For the items that we have implemented, if they are implemented, they are currently in there. Some of the things that we have implemented, we did a lot of stuff in our system walk-down procedure.

And to give you an example, we brought in a look at some of the cable tray and conduit, just routine inspection stuff. The way we state it in the procedure is there is a requirement now that that is done. And we require that a baseline be completed, a baseline inspection, walk-down of that cable tray and conduit, prior to the period of extended operation; i.e., 2010. Then thereafter, it is on a ten-year frequency.

So that is the way we implement it. We

put it in place. And if it is something that you need some time to get done, typically we will spot a timeline. But the requirement is there so they can begin with it.

CHAIRMAN BONACA: So you do have the time? I mean, you have the length of time where you are stepping up to the commitments of the licensing?

MR. STEWART: Yes, sir.

CHAIRMAN BONACA: So you are not really getting into individual commitments in a phased way? I mean, you just --

MR. STEWART: A lot of the commitments we went ahead and put in place because they are that intrusive.

CHAIRMAN BONACA: So you do have a phase. Let me ask you a question about Alloy 600 program. Okay? At some point you are going to institute an Alloy 600 program.

The actions of that Alloy 600 are going to be important for this current period of license preparation, which was the intent. So I would expect that some of those activities listed would be already into effect before 2010.

MR. STEWART: With regards to Alloy 600, we have some of our engineers following what EPRI and

MRP are doing in negotiations with the NRC. We are following their efforts and aware of what is going on, but we haven't implemented anything yet.

The way our Alloy 600 program works, this is not one that we have either implemented or transitioned, but we will put that in place prior to the period of extended operation.

CHAIRMAN BONACA: Okay.

MEMBER LEITCH: I think you told us at the subcommittee meeting that your intention was to have 18 of these programs in place by the middle of 2004.

MR. STEWART: Correct.

MEMBER LEITCH: Is that still your hope?

MR. STEWART: I think going back and forth, it might be 17 now, but that is about the right number. Our main intent is right now all of the commitments were initially assigned to license renewal. And we want to either get them implemented or put them back into the plant organization.

That 18/19 split was first as we work them out shifted back and forth. But I think it is one different than we said in September.

MEMBER LEITCH: Thank you.

MR. STEWART: Now, what happens with the commitments is typically these will go in a program document. We will identify those as a commitment. We flag them as a commitment and indicate, for example, that it belongs to the boric acid control program or Alloy 600 program. We don't have a procedure to do that, but we will flag whatever the program is that is associated with it. What we expect to do then is control the changes by the 50.590 process.

Along with that, what we will do -- and we have taken some steps, but we haven't finished yet in terms of the configuration control process -- is we will incorporate guidance to ensure that the requirements of 54.37(b) are met.

The way we are going to support this is some license renewal training. Some phases of that have been conducted on site already. We expect to do one more round of that by October 2004.

MEMBER LEITCH: Who are the recipients of that training?

MR. STEWART: To date it has been primarily engineering. Engineering is the owner of most of these commitments. I think there might be one or two that will go over to chemistry, but that is primarily engineering.

MEMBER LEITCH: Do you see any impact on operator training as a result of license renewal?

MR. STEWART: No, sir. What we have got is we have got a configuration control process so that if we are doing something with ops procedures, we will be looking at those just to see if they are doing something where they are changing, say, a moat from a standby to normal operating or something that might impact something. We will look at that for license renewal, but we will cover that in some of the screening criteria that we put in when they do their procedure changes.

We also plan on creating a license renewal design basis-type document or equivalent. That will be done this summer. As I stated, we have got a refueling outage this April. So on the schedule we are on, we expect to see the renewed license in April.

So with this UFSCR update that we do six months following the refueling outage, we will have the UFSCR supplement in place. This will be the chapter 18 in our UFSCR. And basically it will be the Appendix A of the license renewal application as we have modified it with responses to RAIs.

That is the last of my presentation. Any questions?

MEMBER LEITCH: Just I would continue. It is not really part of license renewal, but I am a little concerned about the power level on the unit when I see that year to date, you are almost 106 percent. It just seems to me to be awfully high and gives me a little cause for concern.

I would just ask you to take it back to the plant folks if they are familiar with it -- I think it is Byron and Dave who would have -- get them to find out now --

MR. STEWART: About the calametrics?

MEMBER LEITCH: They have been overpowered for several years. I am not sure whether your system is the same as theirs or not, but it would be just something to take a look at. As I say, it is not a license renewal issue at all. It is just something that gives me a little bit of question.

MR. STEWART: I will carry that back. And I know when we installed the ultrasonics that we did quite a bit of calametric testing to match it. And I am not totally familiar with it, but I believe, at least in each cycle, we would come back and do similar calametrics and do a baseline. So we do check it with --

MEMBER APOSTOLAKIS: Is there a PRA for the plant?

MR. STEWART: Yes, sir, there is a PRA.

MEMBER APOSTOLAKIS: And what is the core damage frequency? Do you remember?

MR. STEWART: I do not. Do either one of you? I am sorry, sir. I can get that information back to you.

MEMBER APOSTOLAKIS: Are you participating in any of the risk-informed initiatives? Have you requested any changes in your licensing basis?

MR. STEWART: No, sir. We have not. We have looked a couple of times at the risk-based ISI and have concluded that there is no particular advantage for us. We can't see the benefit of trying to do that. We haven't looked at it. We haven't proceeded with any of that to change any of the licensing basis.

MEMBER APOSTOLAKIS: Are you doing online maintenance?

MR. STEWART: Yes, sir. Now, we do online maintenance, and we do a risk matrix based on our online maintenance. Occasionally when you get a merging item, I will see them shift it around just to lower the risk. So we do use the risk matrix online maintenance.

MEMBER APOSTOLAKIS: I thought everyone was doing that risk-informed ISI. That's not true?

MEMBER ROSEN: No. It's about two-thirds. A lot of them are but not everyone.

MEMBER SIEBER: It seems to me that the idea of going to a risk-informed ISI is to gain a financial advantage but to be able to inspect the most important response to this plan. And so if you approach risk-informed ISI or a lot of other risk-informed initiatives, the thought ought to be that what we are trying to do is improve the safety of the plant, as opposed to getting out of additional work.

MEMBER ROSEN: Yes, to reduce dose as well.

MEMBER SIEBER: Right.

MR. STEWART: And to proceed with risk-based ISI, it is a bit of working stuff on the front end. We still need to go through the review cycle. At Robinson, they have looked at it and have not seen it particularly finish officially for the effort involved to try to do it.

MEMBER ROSEN: Well, notwithstanding the fact that your doses are very low, but there were years in which you didn't have an outage. And when you have outages, you will be in doing inspections.

MR. STEWART: Yes, sir.

MEMBER ROSEN: And some of the things you will be inspecting may yield to risk-informed in-service inspection technology in the sense that you might not have to do them as frequently for the low-risk significant welds. That is something that if you are really interested in pressing on the accumulated dose to your personnel you might look at.

MEMBER SIEBER: Is your PRA a living PRA or --

MR. STEWART: Yes, sir.

MEMBER SIEBER: Was it just done to satisfy the generic letter?

MR. STEWART: No. It is a living PRA and --

MEMBER APOSTOLAKIS: But is it being used anywhere?

MR. STEWART: Yes, sir. We use it. We use it for a number of studies. We use it to help us with the online maintenance that you were talking about. And a lot of times when we start looking at modifications or whatever to the plant, we will look at it in terms of how it reduces some of the risk.

CHAIRMAN BONACA: This plant must have been an SEP plant, systematic evaluation plant?

MEMBER SIEBER: It is pretty old.

CHAIRMAN BONACA: Yes.

MR. STEWART: I am not familiar.

PARTICIPANT: The answer is yes.

CHAIRMAN BONACA: Yes.

MR. STEWART: I do know that the plant is old enough it is basically a pre-GDC plant.

CHAIRMAN BONACA: How is your system configured on this plant? Do you have --

MR. STEWART: We have two motor-driven pumps and one steam-driven pump.

CHAIRMAN BONACA: If everything is housed in this building that you showed in the picture, if you could put it up?

MR. STEWART: The steam-driven pump in the turbine building.

CHAIRMAN BONACA: Yes.

MR. STEWART: The turbine building is right here. And it is open. If you could go back in the first four here? Back on this slide as the steam-driven pump. Now, the motor-driven pumps are actually also from the turbine building, but they are enclosed. They are in a separate walled area back here on the first --

CHAIRMAN BONACA: Is the turbine building pump protected there by walls or something?

MR. STEWART: No, sir. It is pretty open. I mean, the main feed pumps are right here. And it is probably within 30 feet of those.

CHAIRMAN BONACA: So your extent of the events PRA must be pretty high contributors?

MR. STEWART: I'm sorry? I didn't catch the question.

CHAIRMAN BONACA: I was commenting that probably your extent of the event PRA contribution to this is pretty high. I mean, if --

MR. STEWART: Yes. If you look at the condensate storage tank right here, if you go to some of the later plants, I mean, Harris plant, for example, it is closed in a separate building with concrete.

This is the condensate storage tank right here. If you go in the plant, the reactor auxiliary building is wrapped around the containment here. This is the fuel-handling building back behind here.

MEMBER SIEBER: Where is the spent fuel storage area?

MR. STEWART: Right there. Now, if you come off this picture, we have got dry fuel modules back up this way, the inside protected area, but right here is the --

MEMBER SIEBER: That is the wet pool?

MR. STEWART: That is the wet pool. And this crane here is to date, we have been using railroad shipments and taking spent fuel to our Harris plant. This is how we handle the casks, with this crane right here.

CHAIRMAN BONACA: Have you experienced any hurricanes or tornadoes on the site, high winds?

MR. STEWART: Yes, sir. We have one in November 2002. I remember it because I had a new pickup truck, and I got it repainted.

CHAIRMAN BONACA: Did it have any major impact on the plant?

MR. STEWART: No, sir. In fact, that particular tornado, we were shut down for an outage. If you can imagine with an outage, you bring in all sorts of stuff. It actually hit on site, turned over some vehicles, blew some stuff around. But considering we were already shut down when it came through, it was surprising how little it actually damaged inside the plant, even though we had all of the extra trailers and equipment in to support the outage.

MEMBER LEITCH: Okay. If there are no other questions, we will proceed with the staff's presentation now if that okay.

MR. STEWART: Yes, sir.

MEMBER LEITCH: S. K. Mitra will be making the staff presentation.

MR. STEWART: Thank you.

MR. KUO: And also I would like to inform the Committee that we just had Frank Gillespie, the Deputy Division Director, join us. I am sure he will be glad to answer any questions that we have.

VICE-CHAIRMAN WALLIS: We will have to think of a question that only he can answer.

MR. MITRA: Good morning. My name is S. K. Mitra. I am the lead Project Manager for the Robinson nuclear plant license renewal application. It is supposed to be Mr. Caudle Julian, inspector from Region II, is on the line, but I couldn't get him. So there is some kind of glitch there. But we will try to answer the inspection questions, if you have, ourselves.

A little bit of background. We received the application on June 14, 2002. We had an ACRS subcommittee briefing on September 30, 2003 on draft SER with open items.

Since then, on January 20, 2004, we issued the final SER. And the staff concluded that the applicant has met the requirements of license renewal by Part 54. The current license is expiring on July 31st, 2010. And the request for renewal is for an additional 20 years.

Three inspections and two audits were done during the review. Just to make reference to what is the difference between the audits and the inspection, the audits are the ones which staff reviews, the documents at the site. It is generally done by the NRR personnel.

The inspections are the verification of accuracy of the implementation with regard to the aging management program. It is generally done by the original staff.

The first two, the scoping and screening methodology audit, which we did in September 2002, and the scoping and screening inspection, which is in 2003 during March and April.

In the methodology, the staff audited and received the applicant methodology. According to the scoping and screening inspection, the staff found that system structure and components are in the scope of licensing renewal as required by the rule.

MEMBER ROSEN: I guess at that point, I should ask the question about the steam generator feed ring position.

MR. MITRA: We have a slide later on.

MEMBER ROSEN: I will hold it.

CHAIRMAN BONACA: I have a question, a general question, here. Every time we review a license renewal, we see a significant amount of inspections taking place and reviews. I understand that the focus, in fact, is going to move further to the site and everything else.

When you go for an inspection, are you going simply with license renewal issues in mind or are you also looking for specific areas of the plant, either those that have experienced in the past some specific iteration? I know you do that.

And also for a plant like this with an SEP license kind of, you know, there are a number of commitments on the licensing bases which were different from the standard ones. In some cases, there were other systems credited because you do not have a plant which was fully compliant with the SRP at the time.

Are you looking in those areas we understand what the differences of the significance are to the license renewal issue, differences may be simply that the system is not fully pedigreed, yet is used for an application on the licensing basis and then need special attention maybe that is not needed for other plants, where you have multiple trains and that kind of thing?

MR. MITRA: Most of the inspection is done by the region personnel. They have pretty much familiarity with each plant in that region. And they do their inspections other than licensing frequently. If there is any problem or any maintenance or any other issue, they are quite familiar.

They are usually inspectors on site who do most of the inspection. He does the walk-down during the inspection. And they are quite familiar with what is the shape of the plant at that time.

MR. KUO: In general, the region does 100 percent inspection for all systems. For license renewal inspection, the commitment is made specifically to license renewal to be definitely part of the inspection.

CHAIRMAN BONACA: To me, issues like this would come into the scoping first. I mean, we might have some systems that are not to the degree and, yet, they are committed.

MR. KUO: Yes.

CHAIRMAN BONACA: And for those, of

course, you want to have special attention. And mostly it would be that issue.

MR. GILLESPIE: Certainly we are focused on the word "inspection." There are two elements to the scoping. Actually, there are three. One is the inspection. That is after the fact, if you would, in the timeline.

The first one is actually the scoping audit on site, which is actually done out of headquarters. It is our QA group, maintenance QA group, that goes up and does it. They are actually looking at the process of how they went through, which systems they picked.

And so there is that element. Then the second element is DSSA is actually looking at, if you would, to simply, the prints with the crayon lines around it for the scoping. So the one group that is going on site really has to go on site to answer those kinds of questions to evaluate the alternative systems in some of these older plants consistent with the broader scope of the rule itself.

So you have got that group different from the inspection group with the maintenance QA people looking exactly at the question you are asking as an audit. And then you have got the inspectors going out several months later confirming if the licensee has done what they already said it was okay to do.

CHAIRMAN BONACA: Okay. So what you are telling me is that the regional people really have the more focus on the equipment and the specifics and that should be reflected, in fact, in the application in the NRA. And so as you verify the NRA commitments insofar as scoping, somebody has that SEP in mind and remembers that system X was committed to and it should be there, correct, that kind of knowledge?

MR. KUO: Right. Like Frank said, actually, there are three groups of the NRC doing this particular scoping work. That is our inspection program staff doing the methodology audit and the DSSS staff doing the result audit and then regional inspection. So that is really welcome.

CHAIRMAN BONACA: Okay. Thank you.

MEMBER LEITCH: Some plants we see that there are only two inspections here. There were three. What significance is that third inspection?

MR. MITRA: We will come to that slide. Why we do it in the final inspection is because of the inspection, the aging management inspection. We found that there is some concern regarding the tracking. And that's why we went back and did the third.

MEMBER LEITCH: Third inspection. Okay.

MR. MITRA: We did the aging management program audit. NRR staff went there and did that during May 2003. We have the audit report issued on August 3rd, 2003. We audited all of the attributes of the AMP claimed to be consistent with GALL and concluded that most of the attributes are consistent.

There are a few that we identified some differences. We clarified with technical staff at the applicants' sites. And they have revised their basis documents to be consistent with the GALL.

VICE-CHAIRMAN WALLIS: Everything is now consistent with GALL?

MR. MITRA: It is. We have one AMP that we found that the applicant's cable-converted connector program lacked detail to conclude the consistency with GALL. So we asked the applicant to submit it to our headquarter staff for review. They did. They revised it. And the staff found it acceptable.

MR. KUO: If I may, I just want to say that Robinson is the first plant that we started having the staff team to go to the site to do the audit for the consistency with GALL because in the application itself, the applicant simply addressed whether they were consistent with GALL or not without actually the supporting documentation.

So the purpose of this audit is for the staff to go to the site to review the supporting documentation.

VICE-CHAIRMAN WALLIS: And I think that is very important. Now, we are going to see another application later in the day.

MR. KUO: Yes.

VICE-CHAIRMAN WALLIS: And in that one, I think it turns out that everything is not consistent with GALL. So the key question for me was, what did you folks do about those parts which were not consistent with GALL? We will get to that later in the day.

MR. KUO: Yes.

VICE-CHAIRMAN WALLIS: So two questions. Are they consistent with GALL? Check it. What is it? And then what do you do with the ones which are not consistent?

MR. KUO: We will explain that later.

VICE-CHAIRMAN WALLIS: Okay. Thank you.

MR. KUO: Thank you.

MEMBER LEITCH: P. T., while we are on that point, perhaps you could refresh my memory. I think it is Farley, is it, that you are going to move even more of your activities to the site?

MR. KUO: Correct, correct.

MEMBER LEITCH: Has that occurred yet?

MR. KUO: Yes, that has occurred. Our staff team performed the audit at Farley. They actually wrote the audit report and wrote the draft SER based on their audit.

MEMBER LEITCH: So it is still probably six months or so at the subcommittee level until we see the results of that?

MR. KUO: That is correct.

MEMBER LEITCH: But could you make a comment? We are a little off the topic here, but did you find that process to be successful?

MR. KUO: Yes, sir, to the best of my knowledge. And then the feedback that I got from the applicants, it looks like the process really works. How efficient, how effective, we haven't been able to assess yet, but just based on the general observation from the feedback from the applicants, it looks like the process works well.

MEMBER LEITCH: Okay. Thank you.

MR. MITRA: We have done the aging management inspection at the original inspection period, in June 2003. And, as I said, the inspector observed that the applicant had not yet established adequate tracking items in the plant action request database to assure the future task base to support license renewal.

So the inspection report was issued on July 31st, 2003. And, to answer your question, we went back for further inspections to verify that its tracking system is in place. That is the third inspection.

We went back on September. By that time, applicant had loaded its attempts to establish a site action request tracking system and before we went through the tracking system, how they did it. Also we found that there is a transition plan for completion of licensing projects. They have established that. And the inspection report was issued on September 9, 2003.

Now we will go to open items. We had 2 open items and 30 confirmatory items. All of them are resolved right now. As a matter of fact, when we briefed the subcommittee on September 30th, all of them were resolved, but we didn't get the response from the applicant on the open item information.

So we will just discuss a couple of open items that we had at that time. The first one is that staff identified the degradation of feed rings, which is a non-safety-related item, but it is surrounded by the safety-related items. The DNRs or the DNR weld could produce root spark inside the steam generator shell and may damage safety-related components, especially during the transient.

CHAIRMAN BONACA: Is this a generic concern with this kind of steam generator?

MR. MITRA: I think it has generated concern.

CHAIRMAN BONACA: So this is something for which there have been commitments already on the part of other applicants? I remember that.

MR. MITRA: Yes.

MEMBER ROSEN: So what puzzles me about this -- and this is why I brought it up earlier -- is that it seems to me there was a lot of sound and fury here without much significance because this is a matter that should have been obvious to everybody.

I wonder, rather than going through this again and again, maybe, P. T. and Frank, if you might think about ISG, interim staff guidance, or something that would clarify this to licensees and the staff so we could get on to more substantive matters earlier if they exist.

MR. KUO: We will see if this is a subject.

CHAIRMAN BONACA: Yes. And either item can be based, and that will be pumps. They keep coming back up. It should be clear by now that they have to be in the scope of license to do it.

MR. KUO: Thank you very much. Good suggestion.

VICE-CHAIRMAN WALLIS: This comes up with the next license, too, doesn't it, the business about in-vessel components and all of that? The same issue comes up again?

MR. KUO: Right.

MR. MITRA: By the way, the pump was in scope from the beginning.

CHAIRMAN BONACA: Yes. I'm not referring to this application. It just routinely comes up as an item that I think, in fact, was not in the original and didn't come to us as an other item. I know that there was a debate between the applicant and the NRC. So since it come back a number of times, I think it is an appropriate candidate.

MR. MITRA: The other work item is that Lake Robinson had a dam failure and depletion of condenser storage tank in rendering the failure of deep well pump, which caused failure of separation of the auxiliary feedwater system to prevent the residual heat removal. That is the main condition.

As a result of staff finding the deep well pumps, associated piping, and it was according to scope, the open item would result.

VICE-CHAIRMAN WALLIS: So their ultimate heat sink has forward tendencies? It has a lake and three deep wells? There are three separate wells essentially?

MR. MITRA: Yes.

MR. STEWART: The heat sink is consistent with the lake only. We have deep well pumps that we use as a backup source. The preferred source obviously is a condensate storage tank.

VICE-CHAIRMAN WALLIS: Right.

MR. STEWART: And our safety-loaded backup is service water. So we do have service water as a backup if we deplete inventory of the condensate storage tank.

However, our main reservoir is not safety-related. It has been seismically designed. We do inspect it. So that is why this item came up. So deep well pumps are the backup in case we lose the reservoir.

MR. MITRA: This is a TLA aging of boraflex. I am just discussing this slide because the licensee has submitted an amendment to eliminate the credit of the boraflex panel from technical specification.

When we had the presentation during the subcommittee, the staff was still reviewing this amendment. Since then, the amendment has been approved and the document and the license amendment can be seen in amendment number 198 issued in December 22nd, 2003. It is also addressed in our ACR section 4.614.

Finally, we will go to reactor vessel integrated TLAs. And we will have a couple of slides on that. The first one is reactor vessel needle embrittlement. The analysis of pressurized thermal shock is projected to end up with a period of extended operation. And staff independently performed the calculations to verify that. And it shows that Robinson numbers are well under the maximum limit.

MEMBER ROSEN: This is a very good presentation of data as well. Thank you for clearing it up. But it now raises the question, really, in my mind of an older vessel like this within all of this margin. What is it about this vessel that makes it come out so well?

MR. CLEMENTS: When the issue first came into effect, we immediately took action and went to first a low leakage loading pattern in the core. And then since we have put in special part link shield assemblies in the regions of the critical welds that reduce the fluence by about a factor of ten.

We did that in the early 1980s, when PTS first became an issue. And we have maintained those assemblies in the vessel since.

MEMBER ROSEN: I think you are to be commended for that, for those actions. Those are very proactive things to do.

CHAIRMAN BONACA: Yes. Also I think the volumes in these early plants were sufficiently large and spent to the actual size of the core. I think these kinds of plants, like 600, like the electric, you compare them to the modern four-loop with the ISBWRs, just about the same volumes. And, yet, they have twice as much power density now. So I think that is another component. It is encouraging to see that there is this kind of margin.

VICE-CHAIRMAN WALLIS: These independent calculations were not very sophisticated. We were just putting some numbers in a formula that is in Reg Guide 9 or whatever it is.

MR. MITRA: Jim? There are a lot of details that go into it.

VICE-CHAIRMAN WALLIS: There are lots of details? Okay. Do you have to look at the composition of the steel and that sort of thing?

MR. MEDOFF: I am Jim Medoff. I am with the Materials and Chemical Engineering Branch of the Division of Engineering, NRR. I was assigned the TLAs for neutron embrittlement.

There are a lot of factors that go into the pressurized thermal shock assessments. And the upper shelf is energy assessments. They include surveillance data and their specific criteria of how we expect the licensees to incorporate this surveillance data into the calculations. And sometimes that gets a little bit tricky.

So it is not always quite as straightforward as you may think, but I think we have had enough discussions with the industry that they are conforming to the way we expect them to incorporate the surveillance data into the calculations. So the data that you are seeing here should incorporate any relevant surveillance data.

VICE-CHAIRMAN WALLIS: But they are your calculations that are reported?

MR. MEDOFF: But we have a database that has calculational methods that conform to regulatory guidance.

VICE-CHAIRMAN WALLIS: These numbers here are the industry calculations?

MR. MEDOFF: No. The numbers --

VICE-CHAIRMAN WALLIS: Are your calculations?

MR. MEDOFF: The numbers you are seeing here are the numbers that we independently calculated using the database.

VICE-CHAIRMAN WALLIS: You independently calculated? Okay. What did they calculate?

MR. MEDOFF: I would have to go back to the SER and see.

VICE-CHAIRMAN WALLIS: Essentially the same thing?

MR. MEDOFF: I think the numbers compare pretty well between what they --

VICE-CHAIRMAN WALLIS: Presumably if you did the same thing, you would get the same answer.

MR. MEDOFF: Right.

MEMBER SIEBER: Presumably.

MR. MEDOFF: Not always, not always.

VICE-CHAIRMAN WALLIS: No. I am very pleased you did independent calculation. I am just trying to check what was the depth of them and how they compared because I think a lot of our job here is to assess how you went about checking things.

MR. MEDOFF: Typically what we do is we go pull the latest surveillance capsule reports for the plant. We go look into the data, make sure that we have all of the data in the ARB. And if it's not, we update the ARB. And then we perform the calculations.

VICE-CHAIRMAN WALLIS: Thank you.

MR. MITRA: And we have data from reactor vessel upper shelf energy. Again, the analysis predicted an extended operation, and staff began to perform independent calculation. And, again, it shows the limit minimum made by the Robinson.

MEMBER LEITCH: Now here the limit is 50 in all cases, but since the number came out to be below 50, you do an equivalent margins analysis. Is that correct? And based on that, I guess what I would say approved but more refined calculation, 42 is allowable. Am I correctly --

MR. MEDOFF: Let me clarify this. What the rule states is that the criteria for your end-of-life upper shelf energy is 50. If you don't meet that, you are required to do a fracture analysis to demonstrate equivalent margins to the ASME code.

Now, Robinson was a plant that for some other place, they were below the requirements for upper shelf energy in the rule. There are also some requirements for initial upper shelf energy. So they had an enlargement analysis for their plate almost from day one. And the value that got accepted in that equivalent margins analysis was down to 42-foot pounds.

So when we did our analysis for the corresponding plate, we had to make sure that they remained above what was approved in the previous equivalent margins analysis. Otherwise we would require them to come in with a more refined assessment.

MEMBER LEITCH: Okay. Thanks.

MEMBER APOSTOLAKIS: Can you give me a quick tutorial on what "equivalent margins" means or is that something that everybody knows? What is an equivalent margin?

MR. MEDOFF: Well, the rule, the requirement is your upper shelf energies to demonstrate adequate futility of your shelf materials, the rule requires 75-foot pounds before you have any irradiation and 50-foot pounds at the end of the current operating period.

If you don't need either one of those, you have to do what they call an elastic plastic fracture analysis assessment to demonstrate the upper shelf energies. Values that are listed here are really based on linear fracture mechanics assessments.

If you can't meet them, what you do is you do another type of assessment, which is called an elastic plastic fracture mechanics assessment. It postulates some use of plastic deformation at the crack tip. And you do another analysis to figure out what is acceptable under those analyses in terms of the upper shelf and to see how far you can go down if you postulate some elasticity at the crack tip. So that is what it gets into.

VICE-CHAIRMAN WALLIS: George, when we get into PPS, it is a real zoo with all kinds of statistical stuff, data all over the place and all kinds of uncertainty analyses.

MR. MEDOFF: Just to give you some information, --

VICE-CHAIRMAN WALLIS: It is pretty darned complicated.

MR. MEDOFF: -- we have a regulatory guide, and the ASME code has an chapter that we follow for those types of analyses.

VICE-CHAIRMAN WALLIS: But these are all supposed to be conservative-type analysis. If you really get into the statistics of crack growth and all of that, then it gets very complicated and subject to all kinds of uncertainties.

MEMBER LEITCH: Jim, did I understand you to say that this equivalent margins analysis was necessary almost from the get-go?

MR. MEDOFF: I think it may. I will have to get back to you on that, but if I remember correctly, it was because they didn't meet the 75-foot pound initial energy.

MEMBER LEITCH: I see. So they are not necessarily below 50 now.

MR. MEDOFF: It was to satisfy the initial.

MEMBER LEITCH: The initial 75, yes. Okay.

MR. MEDOFF: But I can double-check that for you if you would like.

MEMBER LEITCH: I don't need that information. It was just a curiosity question. Thank you.

CHAIRMAN BONACA: I have a more general question, just a curiosity about. We talked about now we have plants that are coming in and are pretty much fully compliant with GALL insofar as the approaches they are taking.

As we were looking here about configuration with these plants, we saw a plant here, a building that has all the safeguards, which is fully opened practically. It's very different from others, which are more perfected. And so there is a floor.

I would expect that the fact that in some cases the inspectors and also the applicant would have consideration for special programs that are different from GALL.

Now, I know there are enhancements to GALL that are required in some cases, but I think it is left to the inspectors to go and verify that this is, in fact, occurring. What is the process by which that is done?

I am trying to understand who makes this decision. I mean, one may say, "Look, you know, this component is configured this way. And we have a program for GALL, and it is inside. And this other one doesn't have a program for GALL."

There are differences coming from the site configuration and building this on. How are they arrived at? How are they treated, I mean?

MR. KUO: If I may clarify a little bit, Dr. Bonaca? Are you concerned about a security issue or are you --

CHAIRMAN BONACA: No, no. I'm talking about, for example, here we started building. You have a turbine-driven pump that is really exposed.

MR. KUO: Right.

CHAIRMAN BONACA: So in other buildings, you have a turbine-driven pump that is sunk down in the bottom of the building and protected and all this kind of stuff. There are differences there, even from an environmental standpoint. I am sure that the program should reflect or may have to reflect those differences.

I am trying to understand if you say you comply with GALL for both cases, does GALL, in fact, have consideration for environmental conditions for both?

MR. KUO: No. The GALL only evaluates the program per se. That is the aging management program. All the factors, I hope that was factored into the original design array. In license renewal, in support, we are doing it according to the current licensing basis.

MR. GILLESPIE: Mario, let me see if I can get directly to your question because this has come up on plants. For example, we had certain precedents set with open buildings like that, Turkey Point and St. Lucie. It really comes down to the definition in GALL of what is a benign environment.

In general, even the exposed buildings have, for example, for stainless steel casings and piping, where you are looking at the external environment as one issue and the internal environment as another, the internal environment is still the same. The external environment, it is how GALL deals with the word "benign" environment to dismiss it.

CHAIRMAN BONACA: So we think the definition of the attributes that you are requesting, there is a consideration.

MR. GILLESPIE: Yes. So you are going to see Turkey Point, St. Lucie, Robinson, which have this open design, have a heat range and a humidity range, which are basically open to the atmosphere.

I am hoping now I am right. In the definition of benign in GALL, it would be encompassing the heat and humidity ranges versus being in an air-conditioned space, which would be kind of the optimum reverse?

MR. KUO: In the evaluation of GALL, it looks at the parameters that --

CHAIRMAN BONACA: I remember Turkey Point, yes.

MR. GILLESPIE: So I think it is dealt with. And we actually dealt with it specifically because those kinds of questions came up, particularly in some of the things we are doing now in looking back at past precedent to fold it into GALL and where we approved it in a more adverse environment and open environment. But it is not addressed. It has its own air-conditioned space and should be easy to incorporate into GALL.

CHAIRMAN BONACA: In fact, GALL in some cases has expectations for enhancements and stated in the SERs.

MR. GILLESPIE: Yes.

CHAIRMAN BONACA: Okay. Thank you.

MR. MITRA: Caudle?

MR. JULIAN: Yes?

MR. MITRA: Do you want to add anything on this issue?

MR. JULIAN: I would just add possibly a

reminder that although these plants have auxiliary feedwater systems that are exposed to the outside atmosphere, this has been looked at in the current licensing basis.

Of course, one of the premises of license renewal is that the current licensing basis is adequate for the plant. So we don't particularly go into unique aspects that have already been accepted by the NRC.

CHAIRMAN BONACA: Yes. I mean, I asked the question because in this particular case, the environmental condition may be such that 20 more years puts a significant burden on that component just because it is exposed. So that was the reason why I asked the question.

Okay. I've got the right answer.

MR. MITRA: That is all I have.

MEMBER LEITCH: Okay. Any questions for S. K. or the NRC staff?

(No response.)

MR. MITRA: Thank you.

MEMBER LEITCH: Anything else for CP&L?

(No response.)

MEMBER LEITCH: Well, I want to thank CP&L and the staff for their concise presentation. And that will conclude this portion. I'll turn it back to Dr. Bonaca.

CHAIRMAN BONACA: Thank you. So are there any other comments or questions from members?

(No response.)

CHAIRMAN BONACA: If none, I think we will recess now, take a break. We are scheduled to come back at 10:15.

(Whereupon, the foregoing matter went off the record at 9:44 a.m. and went back on the record at 10:14 a.m.)

DR. BONACA: The agenda is interim review of the AP1000 design. I would like to point out before I move to this item that the first part of this meeting is open to the public. At some point, there will proprietary information being shown by Westinghouse, and for that portion of the meeting, the meeting will be closed to the public. And Dr. Kress is going to lead us with his good intention, and tell us when the time is for the transition from open to closed.

DR. KRESS: I sure will. Thank you, Mr. Chairman. Just a couple of comments before we get started. Back on February 10th and 11th we had a Subcommittee Meeting focused primarily on resolution of the thermohydraulic issue. Most of the members were there, so today we're not just reviewing that part of the meeting. This is more of a full certification review where we're going to talk about the open items, and any lingering thermohydraulic issues or any lingering issues at all. And we do plan on having what we call an interim letter at this time. And I want to remind the members, the purpose of this interim letter would be to identify any lingering issues that we may have, for which we want more discussion and information before we can, I guess the word is bless the certification of the AP1000 design. So now is the time to bring up any of those that you want more information on and more discussion, because we're on a fairly fast track. We're supposed to get the SER in September of this year. At that time, we'll probably write a final letter, so that's all I wanted to remind the members of before we get started. So with that, I'll turn it over to -- I guess the Staff is going to start us off.

MR. SEGALA: I'm John Segala. I'm the Senior Project Manager for AP1000 design certification, and the purpose of my presentation today is to provide a status of the Staff's review, to discuss major schedule milestones, and to provide an overview of the remaining draft safety evaluation report open items.

To give you up front what our conclusion is, is we're on schedule to issue the final SER on September 13th, 2004, which was our original schedule.

If you look at where we are right now, we received -- we completed our pre-application review in March of '02. Westinghouse submitted their design certification application on March 28th, 2002. NRC accepted their application for docketing on June 25th, and we issued our draft safety evaluation report on June 16th, 2003 with 174 open items. And our review is progressing nicely, and I'll talk some --

MR. APOSTOLAKIS: Why does it take so long between the submission and the acceptance of the application? Is anything happening during that time?

MR. SEGALA: We have to review the application to make sure that it's a quality application, and there's usually some iteration involved where the staff will look at the document and make sure that it's a good submittal.

MR. APOSTOLAKIS: Good in the sense that it --

MR. SEGALA: It has all the necessary information we need to do a review. And keep in mind, the design control document is a very large document, multiple volumes that we have to review.

The schedule milestones, I have the March 31st, 2004 is our next milestone. We sent a letter to Westinghouse laying out our milestones, and this one is that we wanted all open items successfully resolved by March 31st. And the next milestone you see there is in red. The reason why I have those --

DR. LEITCH: You said something a little different than the slide indicates. You said resolved by March 31st, or that you have responses from Westinghouse by March 31st?

MR. SEGALA: Acceptable responses.

DR. LEITCH: Okay. So by March 31st you will have not only received the responses, but determined that they're acceptable.

MR. SEGALA: That's right.

DR. LEITCH: Okay. Thank you.

MR. SEGALA: The scheduled milestones I have in red are highlighted because that's really what our critical path is in terms of we -- because of our September 13th final SER date, we're having the Full Committee Meeting on July 7th through 9th.

DR. KRESS: That's when you expect our final letter, I think, isn't it?

MR. SEGALA: Yes. And the June 25th date is we want to have our final future Plant Subcommittee Meeting in June, and we need to provide you a no open item final safety evaluation report with our branch chief concurrence a month before that, so that's when you'll be receiving our final version of the FSER. It still will need OGC review at that point. We'll have lot of OGC review at that point, but not all of it.

May 31st is a date that we had a milestone for the final design control document revision to come in, so that would be the final version that has all the changes that we need to do a review.

The next slide here is laying out the -- it has a chart on there of how we resolved open items over time, and it just shows you a depiction of how we -- red is the open items and how they've gotten resolved over time. We have ten remaining open items, and I'll discuss that in some future slides here. And there was 174 total, so we have 164 where we have technical resolution on.

Two of our ten open items are on security. Our security review, we've done a review and we had Westinghouse create a new COO action item that deferred the security plan to the COO applicant. And the staff is currently right now reviewing the ITAAC related to security, and we hope to get that wrapped up soon.

DR. KRESS: Now we have excluded security issues from their review.

MR. SEGALA: Yes. I'm just letting you know what all of our issues are, so that it's clear to you what we have left to resolve.

MR. APOSTOLAKIS: So is security an issue or not?

MR. SEGALA: It's a remaining open item. I don't see it as a significant issue.

MR. APOSTOLAKIS: Now what exactly does it -- this is a opening meeting, but is this the first time we're dealing with security in a certification process? I don't remember doing that.

MR. SEGALA: Yes.

DR. KRESS: It's not exactly the first time because there are regulations on the book that the Staff reviews to see if they followed them with respect to security.

DR. POWERS: Dr. Apostolakis, you'll recall for the AP600 that, in fact, we ran into a problem where the security was interfering in the fire protection.

DR. KRESS: Right. But we never brought

it into our reviews since the new security up-rates I call them have been put in place. I don't know whether it's in there. I just don't think it's part of our purview to do that. There's a separate process that goes on that normally we're not too involved in.

DR. WALLIS: I think the point is, though, for the Staff to think about is whether it's wise to defer all this to the COL, because there may be aspects of the design itself, generic design which have a big effect on security. And just deferring it to the applicant may not be the appropriate way to catch those elements of that design.

MR. COLACCINO: If I could chime in - this is Joe Colaccino of the Staff here. Just for a little bit of background, in the AP600, Westinghouse presented a complete security program, and they intended to do that for the AP1000 also.

In the wake of all the new orders that are coming out post 9/11, we had a meeting, we had a safeguards meeting with Westinghouse to discuss how they should move forward on that. After that meeting, Westinghouse decided to defer most of the security review to the COL. And in the meantime, part of our review has been to make an assessment of what aspects of security are within the design of the plant itself.

And there are those aspects, and that's probably not something you'd want to discuss with the public. So we have thought of that point, and we are progressing with that review. And John has just brought them up, is that we have two of the ten open items that he has in the review are security open items, just for the ACRS Staff to understand what those are.

DR. LEITCH: When I see words like "defer security plan to the COL", it implies that a plan will be devised, a security plan will be devised at that stage to deal with the certified configuration of the plant. But my question is, are there security implications related to the general configuration and footprint of the plant?

MR. COLACCINO: And the answer is definitely yes, and the Staff is working to resolve those. Westinghouse, I think in the sake of the scheduled time, I'm speaking for them - but it's my impression that in order to not address these issues, they went with what the other design certifications went through, ABWR and System 80 Plus, to defer much of the security review to the COL, so it's not without precedent what they have done. And that has been our focus of NSIR's review, which is still ongoing, is to ensure that the aspects of the design that are related to security are covered.

MR. APOSTOLAKIS: Well, Tom, you asked whether --

MR. CUMMINS: This is Ed Cummins from Westinghouse. I think the implication that we didn't do anything in security is not correct. And I think, without getting involved in the details, what we did for AP1000 was identify the vital equipment and identify the vital area. And that's in contrast to the AP600, where we also identified the protected area, the protected area defense, if you will, and the guard force, so the portion that is being deferred to the COL is the definition of the protected area, the defense also of the protected area, and the nature, number, and location of the guide force.

MR. APOSTOLAKIS: Tom, is that something that we might want to look into more carefully in a closed meeting?

DR. KRESS: Well, the name of our Committee is Safeguards, which is a real misnomer. We have traditionally not -- we've left this up to the Staff traditionally to deal with these issues. And so I don't know if it's something we need to get into or not.

MR. APOSTOLAKIS: Well, in light of the

new era, maybe we should at least be briefed as to what is going on.

DR. KRESS: The briefing, of course, we can have and the Staff would probably be willing to do that in closed session.

DR. POWERS: Dr. Kress, it seems to me that in light of our experience with AP600, the issues of security that come promptly to mind is interfering with any of the emergency response activities at the plant.

DR. KRESS: I think that would be an issue, but that tends to be site-specific.

DR. POWERS: Well, the specific things that it came up is when you configure your access to vital areas in a way such that the fire gate can't respond, then --

DR. KRESS: Yes, on the plants.

DR. POWERS: Then you've got something that just not tenable.

DR. KRESS: Yes. That's the problem we have with AP600.

DR. POWERS: Right.

DR. KRESS: Well, we haven't looked at that aspect on AP1000 yet. It might be something we want to get on our list. This is a meeting where we're going to identify any further things we want to look at, and if we want to look at that, we need to have it on our list of things that we -- we'll put it down in writing in a letter to Westinghouse and the Staff. Well, the letter goes to the Staff, but Westinghouse will get a copy of it.

DR. POWERS: They get to do all the work.

DR. KRESS: Yes. And this -- you know, if we want to look at things like that and think it's part of our review, we need to think about it and get it on -- if we decide to get it on this letter, now is the time, because we don't have a lot of time left before July. You know, in July, that time frame we'll be writing a final letter. Anyway, it's a good point. I don't know what to do with it right now. We can discuss it later, I guess.

MR. SEGALA: Okay. The next issues are regarding aerosol removal coefficients. We have three open items regarding this. Two of the three open items are really related to performing dose analysis calculations. However, the other open items on aerosol removal coefficients, but we can't finish the earth analysis calculation until the aerosol removal issues are resolved.

DR. KRESS: Your problem with that was

just how did you arrive at this particular lambda value?

MR. SEGALA: Yes. And I guess --

DR. KRESS: How do you plan on resolving that?

MR. SEGALA: Westinghouse has developed AP1000 removal coefficients in the DCD, and we have a contract with Sandia National Labs to determine if these coefficients are applicable.

DR. KRESS: Oh, I see. I didn't read far enough.

MR. SEGALA: Okay. And they're doing a Monte Carlo Uncertainty Analysis. They've done 200 runs of MELCORE for the double-ended DVI line break, and they're providing plots of removal coefficient over time as they vary different inputs.

DR. KRESS: And this is for the one sequence only, the double-ended DVI line break.

MR. SEGALA: Yes. And they provided us a draft report, and we're reviewing that as we speak. And we're going to take the information from that and use that to run independent dose calculations with Westinghouse and Sandia's removal coefficient.

DR. KRESS: What sort of source term will you use with that?

MR. SEGALA: The alternate source term.

DR. KRESS: Alternate source term.

MR. SEGALA: The next item is regarding leak before break. This last remaining issue that we have is Westinghouse is using leak before break for their main steam system piping, and Reg Guide 1.45 i written for identifying the leakage detection systems for the RCS. And for the RCS, it recommends that they have redundant and diverse leakage detection capabilities.

For AP1000, the RCS, they use the sump level indication. They use radiation monitors, and they use a mass balance approach as their diverse means for identifying the leakage.

Although this Reg Guide doesn't directly talk about the main steam system, the Staff doing the review felt that the same criteria for the RCS should reasonably be applied to the main steam system. So for the main steam, Westinghouse is using the sump level as their indicator of leakage, and the Staff feels that we need a diverse means of identifying that. And we've been having discussions with Westinghouse regarding this issue.

These last four of the ten remaining open items are more administrative open items. These were open items that when we were writing the draft report, there were certain items that we did not complete at the draft stage, so we put in placeholders as identifiers that we need to take certain actions. The first one is reviewing the final design control document revision. I talked that we had that milestone for Westinghouse providing us the final DCD, so we're going to have to review that to make sure that it captures all of our changes.

In terms of the Tier 2* information, and COL action items, we're trying to make sure that all those are what's in the design control document, and what's in our FSER are consistent, and that the Staff has accounted for all the information.

And the last one, documentation of the AP600 FSER information - there were certain chapters where we had pointed back to the AP600 FSER, and we're trying to go back and make this a stand-alone document for those chapters.

So in conclusion, we're on schedule to issue the final SER by September 13th, 2004, and I open it up to any questions or comments you might have at this time.

DR. BONACA: Just a question I have regarding your slide number 8. You say Westinghouse is using leak before break for main steam piping. What does it mean? It means that in the analysis of steam line break, assuming a small size break? I'm trying to understand what this is.

MR. SEGALA: Well, I think the approach is that if you have a leak out in the main steam system, that they will identify the leakage so, therefore, they won't need all the pipe restraints for pipe --

DR. BONACA: So it is for the pipe restraints.

MR. SEGALA: Yes.

DR. FORD: I had four items relating to potential material degradation questions. Are these regarded in this system as open items, or have they been closed?

MR. SEGALA: We asked Westinghouse. We sent them comments on all four of your questions. They became open items, and they are all resolved at this point.

DR. FORD: And we'll be hearing that resolution in June, in July -- in June.

MR. SEGALA: Yes, in the June --

DR. FORD: We'll be hearing that resolution.

MR. SEGALA: Yes.

MR. ROSEN: I had concerns about ADS4 squib valve reliability.

MR. SEGALA: Okay.

MR. ROSEN: And there's been much discussion about that, and a lot of data passed back and forth. And it seems to me now where we are is that the data has been presented that the valves are likely to be highly reliable, based on the performance of smaller valves, but there still needs to be some extrapolation of the data to this 14-inch valve actually with a 9-inch throat for the squib valve. That kind of extrapolation seems to be within the expert's views of what's potentially possible and useful, but it is still true, it remains true that there has not been a valve of this size fabricated yet, or tested. And this leaves at least me in the position of wondering, if you go to certification now, you're certifying a plant with a component that has never been tested, in a size range that has never been tested.

Now it's a little troubling, not a show-stopper for sure, but troubling in any event. It seems to me that where we are, and now I'm really reaching for help on this thinking - that maybe this is a case where we are in design acceptance criteria space, DAC space, in that this is an item for which the level of detail isn't now being provided at the time of the certification. And that the as-procured, and as-built characteristics we don't have because the valve hasn't been built in this size. So it would seem to me that - being novice now, so I'm not sure that this applies - but it seems that it would be possible to apply a DAC on that at this point for the Staff to define what the as-built characteristics are that will be required to be shown, and make that part of the certification. Am I way out in left field with these thoughts?

MR. SEGALA: Well, I can at least give you some of the Staff's thoughts on this issue. When we were doing the PRA review and we looked at the reliability numbers that Westinghouse had in their PRA, we didn't necessarily feel confident in those numbers, so we had a PRA Sensitivity Study done where we increased the failure probability by an order of magnitude, and the CDF increased by a factor of 3.

MR. ROSEN: That's pretty significant.

MR. SEGALA: Well, it went from a value of 2.4 times 10 to the minus 7, to 7 times 10 to the minus 7. And in our review, we felt that that increase in risk was not large enough to impact the

PRA conclusions in terms of the insights about the design.

DR. BONACA: Have you established criteria that says we would accept an increase in failure rate of up to this much for this design to be the most threatened at the time in which the valve would be built and tested, I guess.

DR. KRESS: I don't think you're ever going to get a failure rate for this thing. And what I think we have to rely on is, they will do inspections, testing, and they will check the valve to see, it's supposed to meet the design specifications. They'll test the wiring that goes up to the firing mechanisms. They'll check the firing process, but we're not ever going to get enough data on these valves to get a full reliability. And I think we have to rely on this testing and inspection program, plus the calculating reliabilities based on extrapolating from smaller.

MR. ROSEN: Well, I agree with you on that. I'm not suggesting --

DR. KRESS: Yes, but --

MR. ROSEN: I'm willing to rely on, for example, the Sandia squib valve reliability studies.

DR. KRESS: Yes.

MR. ROSEN: I'm not suggesting the -- what I'm suggesting, because you're answering a question that's different than the one I'm posing.

DR. KRESS: Oh, okay. I'm sorry.

MR. ROSEN: And the one I'm posing is, should the Staff be defining now with Westinghouse what the new valve, when they finally build one, will have to -- what characteristics will be required of this new valve when they finally build it? Not the reliability characteristics, but the physical characteristics of it.

DR. KRESS: I think that is part of the certification. Plus, the testing and inspection requirements are part of it.

MR. SEGALA: These are ASME Section 3, Class I valves, and they'll be build and designed in accordance with the ASME Code. And in terms of the testing, there are ITAAC that will verify that the valve is built in accordance with ASME Section 3. There's ITAAC that they'll do a type test on the ADS 4 where they can build a like version of what's going into the plant, and they will test it to assure that it actuates.

And in terms of the actuation logic to the valve, when we've done LER searches on the smaller squib valves in the slick system, the BWRs, most of the failures have been due to actuation of the valves. And Westinghouse has their PMS System that automatically and can manually control the valves. Plus, they have their DAS System, which is a diverse system that they can manually actuate the valves. And there are ITAACs on that.

MR. ROSEN: Tell me more about the ITACCs on the type test.

MR. SEGALA: Well, I mean, they have an ITAAC that -- I have it written here. The automatic depressurization valves identified in the table perform an active safety-related function to change position as indicated in the table. Tests of squib valves will be performed that demonstrate the capability of the valve to operate under its design conditions. Inspections will be performed for the existence of a report verifying that the as-installed squib valves are bounded by the test or type test.

DR. KRESS: I have a question about that too. It's in my mind very important that the depressurization of the system take place like we think it's going to, which to me means that we have to pretty well predict the blowdown, sonic flow these valves, through the ADS-4 valves.

MR. SEGALA: Yes.

DR. KRESS: Is there any plans to verify that the calculated blowdown flow rates through these valves are bounded by our calculations? Are there any tests planned for that?

MR. SEGALA: I believe there is an ITAAC on the DP through the valve.

DR. KRESS: Yes, but that's flow resistance, and I don't think -- I'm worried about the sonic flow and the choke point, and the effective area to go with your sonic flow velocity calculation. You know, I mean some sort of a verification test that the blowdown rates are what we think they are.

MR. ROSEN: It seems to me you've invited the members, Tom, to put on the table our concerns now. And I've enunciated one concern I have, and you've enunciated another, but it's also about type testing of these critical valves. I think you're exactly right. I mean, without real assurance that these valves are actually going to work, I mean we really don't have -- I don't get a good feel for this design. And the more we can probe these issues with respect to these valves and get comfortable about them, I think the better off we are. And so is there going to be another opportunity for Westinghouse and perhaps the Staff to give us some more assurance in this area?

DR. KRESS: Well, with respect to your part of it, I think they would ask what more do you want that they haven't already given in terms of this assurance that the design is like they say, and the reliability is close to what it is. And that they conform to the ASME standards, and so forth.

I think the question would be what more do you want them to give you. And in my case, I just don't think the delta P measurements - the answer to my question of whether the blowdown rates are calculated correctly or not. But in your case, I don't know what else they can give you. That's the question I would have. And if you've got some ideas, I'm sure they'd be willing to consider it.

MR. ROSEN: Well, they could build one and test it, and give me the results of the test.

DR. WALLIS: But you might want to --

MR. CUMMINS: This is Ed Cummins again. I think the ITAAC that John just read forces us to build one and test it, so it does it in the framework of delivery at the plant, rather than a framework of design certification. But those are the typical sort of ITAACs for environment qualification, and those aren't the only valves that we have to do that with, or only devices that we have to do that with. So we have to build them and demonstrate that it's qualified to perform in its environment.

DR. WALLIS: Building one and testing it won't tell you much about its reliability.

MR. ROSEN: No, it won't tell you anything about reliability, but I've accepted the reliability argument.

DR. KRESS: Yes.

MR. ROSEN: My arguments have progressed.

DR. WALLIS: So you just want to have one test that --

MR. ROSEN: Well, first that they can build it and meet the ASME Code.

DR. WALLIS: But they can build it.

MR. ROSEN: And then second, that when they test it, it does, in fact, meet the requirements. And I'm troubled by this. I think it's a process issue, not an issue with the Staff or an issue with the AP1000 design. It's more of a process issue of the way we certify the -- do design certification, that when you have a unique component that you don't have real data on, performance data or plant operational data, the demonstration of its capabilities is deferred to so late in the process. This is troubling.

DR. KRESS: Okay. I think we've talked that one through.

MR. SEGALA: Okay.

DR. KRESS: It probably will show up in our letter, interim letter as needing something additional. I'm not sure what.

DR. LEITCH: I would like to just cycle back to the security issue for just a minute within the constraints of an open meeting, to make sure I've articulated my concern. Deferring the security plan to the COL - now what I think I'm hearing we mean by the security plan is describing what the protected area is, describing what the vital area is, and managing that. And I think one can develop a security plan for any particular plant configuration. You can develop an acceptable security plan, and that's what's being deferred to the COL phase, and properly so. I don't see any problem with that.

My question is have we learned anything since September 11th that might reflect on the bigger picture, the layout, the configuration, the footprint of the plant? Has anyone thought about those kind of issues? Because it seems to me, those kind of issues, the window for addressing those is rapidly closing. And now if, in that context, there has been work done on addressing those particular issues, I think we need to hear about that in a closed session. And I guess what I think I hear you saying is that there has been some work done. We just haven't heard about that. Is that a correct --

MR. COLACCINO: Yes. This is Joe Colaccino. Yes, it has, and possibly as a suggestion, although I can't say this for certain. I haven't talked with NSIR yet, obviously, but we possibly in the June meeting of the Subcomittee that we could NSIR and go into a closed session and have a briefing for you and discuss the things that have been done with security related to the design of the plant itself. I don't see why we couldn't do that, and we'll just have to get with NSIR and ask them.

MR. APOSTOLAKIS: Would June be a little too late, especially if this part has to be closed. I mean, we have to write the letter in two or three weeks afterwards.

MR. CUMMINS: It depends when we're going to get the FSER. We're not going to get the FSER until late-May.

DR. BONACA: We're going to get an update of program security and safeguards probably in this May time frame. We could have --

MR. APOSTOLAKIS: Then let's make that part of the --

DR. BONACA: Ask for a presentation on this issue at that time.

MR. APOSTOLAKIS: Yes.

DR. BONACA: We're saying that we will have another meeting on security and safeguards probably in the May time frame. Could we have an update on this issue?

MR. COLACCINO: Okay. We can certainly ask and bring that back and talk with ACRS Staff on that. I just want to remind you, in case it's not clear to everybody, that the security plan is being reviewed to the current regulations, Part 73. The ICMs or ISDPT are not part of that review, so there is an understanding that that takes place, but really what the plant design is being reviewed to is Part 73.

DR. POWERS: Dr. Kress, have we had an opportunity to discuss containment failure modes for this particular reactor?

DR. KRESS: No, we haven't, other than the pressure and temperature meets the BVA requirements for the LOCAs and DEDVI steam break. Other than that, we haven't talked about containment failure modes. Would you like to bring that up as a potential issue?

DR. POWERS: Well, I recognize we have limited data on containment failure modes for steel shell containments.

DR. KRESS: This is beyond-design basis.

DR. POWERS: It is beyond-design basis. But what data we have to indicate the potential for catastrophic failure and the absence of measures to prevent that, and I'm wondering if we have taken those steps to prevent catastrophic failure.

DR. KRESS: I will leave that up to Staff or the Westinghouse people, but let me ask you a question about that. If in PRA space, we're calculating a LERF which is a substitute for maybe a safety goal or acceptance criteria, does it matter whether a LERF is catastrophic failure or -- I mean, a LERF is a LERF. That's the question I have. What are the implications in terms of acceptance criteria of catastrophic containment failure?

DR. POWERS: I think if you --

DR. KRESS: We've done the transport or something.

DR. POWERS: I think if you explore how the LERF criteria are set up, you'll find that they're all very gentle and graceful failures when they calculate consequences for those LERFs.

DR. KRESS: Okay.

DR. POWERS: And we don't have events like catastrophic failures like a redeposited radionucleid incidence.

DR. KRESS: So you're worried about when we do the plume calculation in the NRT that a catastrophic-type failure is not reflected very well.

DR. POWERS: That's right. I believe you'll find that whatever consequence has been done and established in those LERFs, there was a presumption that all we were going to do is get a puff release of the material that was suspended in the containment atmosphere at the time of the failure. We weren't discussing the potential of re-suspending every radionucleid that you deposited in the reactor containment.

DR. KRESS: I see. Yes. I see what your concern is there now. No, we didn't discuss that at all, and they haven't even brought it up as an issue that I know of. And I'm not sure how one would deal with re-suspension issues in PRA space, because AP1000 is almost a wet deposition. And a lot of this stuff may have -- at the time of failure of the containment may have made its way down to the sump already. And the question that might be in my mind is whether you have a sudden release from that sump, due to the fact that it's reduced pressure may nucleate and give -- but it's a question, I don't know if it's within PRA space. Well, I'm pretty sure it hasn't because the release is usually the puff of what's left in the containment when it fails.

DR. WALLIS: Well, if this containment fails presumably that tank of water would also fail catastrophically, would come tumbling down wouldn't it?

DR. KRESS: Yes, but I don't know what you'd do with that.

DR. WALLIS: Well, you could have even more of a flood in the sump, stir everything up.

MR. CUMMINS: This is Ed Cummins. I don't think the water has any relationship. It's held by the concrete structure, the steel containment is independent. And, Dr. Powers, I'm not sure -- we're trying to understand your comment. The failure mechanism of the containment is what kind of thing, a slow increase in pressure, hydrogen burn, or what are you thinking?

DR. POWERS: I guess the answer is yes.

The experiments that I'm aware of were free-standing shell containers or upward slope pressurizations. But I presume that an energetic combustion at the wrong time in the containment's history could produce a coastic static pressurization. I'm not sure that I'm thinking about any dynamic lodes on the containment.

DR. WALLIS: What do you mean by catastrophic failure? Do you mean that the whole thing blows apart in many directions, or a big hole blows in it?

DR. POWERS: Yes.

DR. WALLIS: If it blows apart in many directions, presumably the concrete and the steel blown apart?

MR. CUMMINS: I doubt that the concrete would be, but it would be once the steel vessel has broken, it would be open to the atmosphere, so there could be a release of fission products. We do have some vent capability that we've talked about in AP600, and through the spent fuel pool, actually. So that would require operator actions, but --

DR. KRESS: And you have igniters?

MR. CUMMINS: We have igniters, yes.

DR. KRESS: And you've pretty well demonstrated, I think, that you have significant natural circulation patterns to not worry considerably about stratification of hydrogen.

MR. CUMMINS: Yes. We actually say because we have much more robust situation than any other containment.

DR. KRESS: Well, it's a thought, Dana. I don't know what to do with it right now. Especially when you already have a LERF that's 10 to the minus 8. But a lot of that is based on the fact that the CDF is pretty --

MR. ROSEN: And that's based on the performance of the squib valve.

DR. KRESS: To some extent. But anyway, I'll note that one down as something we can talk about and debate over what goes in this interim letter. You can have the floor again. Are you through?

MR. SEGALA: Yes, I'm done.

DR. KRESS: Okay. I guess then, Mario, this is the time we want to close the session.

DR. POWERS: One additional question.

DR. KRESS: Okay.

DR. POWERS: Have we satisfactorily resolved the in-vessel retention issue?

DR. KRESS: I don't think so, and what we've heard is that they've made steam explosion FCI calculations just in case it didn't work, and have told us that these FCI calculations do not fail containment. Now we haven't seen the details of these calculations and what they use for the energetics or how they calculate the energetics, so in my mind we still may need to review the details of the coolant interactions, particularly what they use for initial conditions, in view of the fact that there may be more metal in there than they -- our view may be that there may be more molten metal in there than they used in the calculations, and maybe at a higher temperature. And it may affect the energetics, so I don't think we've heard enough on that, so that may be one of my issues I'll put on the list that we need to hear a little more about, and it's the details of that calculation and what the initial conditions are.

Okay. I guess this time, Mario, is when we need to go into closed session. We have to be sure that there's nobody in here that shouldn't be.

DR. BONACA: Okay. So we're asking for everyone who is not involved with the presentation from Westinghouse and the Staff on AP1000 to please leave the room now.

(Whereupon, at 11:02 a.m., the proceedings went into Closed Session.)

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

(1:30 p.m.)

CHAIRMAN BONACA: Okay. Good afternoon. The meeting will get back to order now again. And we are going to be reviewing the license renewal application for the Virgil C. Summer Nuclear Station.

I will lead this discussion. We received the SER for review I believe in November, and we had a subcommittee meeting with the applicant on December 3, 2003.

There were no open items on this application. In fact, no open items and no confirmatory items as of December, and this was a first. So that's one of the reasons also that caused us to advance our review from May to March.

We are here now to have a presentation for the whole committee from the applicant and then from the staff.

Did you have any comments?

MR. KUO: Well, thank you, Dr. Bonaca. Just again, for the record, that I'm P.T. Kuo, the Program Director for License Renewal in the Environmental Impacts Program. And the Project Manager for the safety review of this application is Dr. Raj Auluck. He is going to make the staff presentation today.

Other than that, I really want to thank the committee to accommodate our schedule, to shift the schedule. Originally, this was scheduled for in May. But because we were able to complete the safety evaluation earlier, so we requested to push the schedule up. Really appreciate that.

Other than that, like, Dr. Bonaca, you mentioned that this is the first time that we reviewed an application. There was no open item at the draft SER stage. It was a really good review that we thought -- that resulted in no open item at all.

If there's no other questions for me, I would like to request the applicant to make the presentation first, and then the staff presentation will follow.

CHAIRMAN BONACA: Okay.

MR. KUO: Thank you.

CHAIRMAN BONACA: All right.

MR. PAGLIA: All right. Thank you. I'm Al Paglia. Good afternoon. I'm Supervisor of the Plant License Extension Project.

As far as the agenda this afternoon, what I thought I'd present, based on some feedback, we'll just touch on the background and history of the plant, the application and development, and then talk through some issues of interest that were identified, and close out with a little discussion on the commitment, tracking, and living program that we're putting together at this point.

Background on the plant -- again, most of you are aware, but we are a 1,000 megawatt three-loop Westinghouse PWR, initially licensed in 1982. SCE&G is a two-thirds owner with Santee Cooper, our public-run utility owning one-third.

We did steam generator replacement in 1994, followed by an uprate to 2,900 megawatt thermal in '96. And all our indicators right now are -- and findings are green.

The application -- we were in that class of 2002, the first of the GALL plants, and developed the application, of course, in accordance with the guidance documents and the standard review plan, and did the GALL comparison. A large percentage of our application and results were ultimately consistent with and comparable to GALL.

The first of the issues, which was the big issue for us back in 2000, was the hot leg crack. What we did, of course, is to replace that weld with a spool piece a little over a foot long using new 690 weld materials. The root cause that we did, quite extensive, but what it boiled down to in the end was residual stresses, tensile stresses, remaining on the ID after initial weld installation and subsequent repairs. There were some fine repairs to that weld at the time.

We also in that outage did an NDE on the other loop nozzle welds, and none of them showed any recordable indications at that point.

Now, subsequent to refuel 12 and refuel 13, we went -- the lower internals remained in. We went in and we did -- and, of course, we repaired alpha loop, so we went in and looked at the bravo and charlie loop welds, and it showed one recordable indication by UT in the bravo loop. Improvements in UT allowed it to become visible. It was there before in eddy current. All early indications were subsequently identified -- reidentified.

We went through what we called a mechanical stress improvement process where we physically deformed through hydraulics the pipe to put the ID in a compressive state. We did that process -- after we did that process, that one recordable indication went away, basically squeezed it to the point where it was invisible to UT.

And based on our stress analysis, and so forth, the ID surface now remains -- is in a compressive state and remains in a compressive state. So hopefully we have, if not eliminated, significantly reduced the primary driver -- a primary driver for TWSCC.

MEMBER LEITCH: How extensive was the MSAT that you used? Did you do it on all the welds or just the parallel welds of the one that had failed or --

MR. PAGLIA: We did it on the hot leg welds.

MEMBER LEITCH: On the hot leg welds.

MR. PAGLIA: Yes, the two that were not yet repaired.

MEMBER LEITCH: Okay.

MR. PAGLIA: That's right, bravo and charlie.

MEMBER ROSEN: Do you have a picture of this? A backup --

MR. PAGLIA: I do have a graphic of the repair that I'll show in just a second. So I'll go through that.

CHAIRMAN BONACA: Of interest to this committee, by the way, is going to be -- by now clearly you have inspected and reinspected. It would be more some of the industry activities taking place, and you have committed to follow those to improve the volumetric inspections, so that this kind of event is not going to happen in the future at other plants.

I know there is an activity in the industry. The NRC is involved in that. I would like to hear from your perspective what is taking place, what gives us better confidence today that some of these indications will not be missed today. I mean --

MR. PAGLIA: Well, I think we had a very good outcome from refuel 14, which we just completed in October. This was a 10-year ISI for us, so we went in and we did both eddy current and the E-ultrasonics on all of them. And the end result of it all was that we identified everything we identified before. There were -- there was no crack growth. That I think is the key piece.

And this is based on the eddy current, which is not the qualified process but one that is improving and one that we use. And then, of course, in UT there was no formal indication. So, and based on that, we -- of course, NRR reviewed that and approved a startup and allows us, at this point, for continuing on making improvements. And we are engaged with EPRI and others to improve UT technology and capability, but we -- we are now on an ASME code-directed inspection regime.

CHAIRMAN BONACA: Well, the next question I have is: does it mean that EPRI now is recommending that you do volumetric inspection? We also do eddy current and a defined superficial --

MR. PAGLIA: At this point, that's not in the -- that is not --

CHAIRMAN BONACA: It's not yet. So this is just your initiative because you found that in your particular case that was the determining factor.

MR. PAGLIA: Yes, sir. And in the future, we are not -- at this point, we are not planning on doing eddy current in the future. We are planning on relying on UT as allowed by the code. But I would say -- and I'm not the expert here -- but there are some significant improvements being made in the UT, and we even noticed those between refuel 13 and 14.

And it really has to do with the foot sizing and the tracking on the surface is really where -- and the coupling, and so forth, where the improvements are being made. So we're getting more ability to see these fine cracks, and certainly before they became significant enough to become a safety concern.

Now, we feel fairly comfortable in our ability to see what's going on at the plant.

MR. CLARY: I'm Ron Clary, the Project Manager. One other point on our future 10-year window -- just based on the code, we will be reinspecting the bravo hot leg every other outage until we finish this 10-year window. And that's driven by the code requirements --

MR. PAGLIA: Right. For that recordable indication.

CHAIRMAN BONACA: Well, I guess --

MR. CLARY: That previously recordable indication.

CHAIRMAN BONACA: I guess I worry about the other plant there. We don't know which one it is, but it may have had a crack similar to yours. It may be working its way now for about 20 years, hasn't come out yet. And with the normal UT, with improvements you say, but without eddy current, identify those cracks. I don't know.

MR. PAGLIA: Well, you know, to be honest -- in our particular case, we don't believe that the crack that we had in 2000 was there for an extended period of time. We believe it propagated through in a fairly short period of time like a cycle length, which we did not see anything in the previous --

CHAIRMAN BONACA: But you had other indications you didn't see -- on the B nozzle, for example. You didn't -- you had an indication later on when you went with eddy, but you hadn't seen it before with the UT.

MR. PAGLIA: That's correct. That's correct. I mean, the eddy current does identify that surface cracking early before UT would see it.

And another complicating factor -- and, again, I'm sure you are aware, the nature of primary stress water corrosion cracking, it's not a very planer-type crack, and the irregular surface tends to diffuse the signal. And that's the reason why you don't get the amplitude and the -- why you don't get the feedback that you need. That's the complicating factor.

MEMBER ROSEN: Well, I have questions like where did the crack initiate, and all of that. But you're going to show the picture of that.

MR. PAGLIA: Yes, I am. We'll do that, yes.

MEMBER SHACK: On your 152 repair, how many weld repairs did you have to make in that weld?

MR. PAGLIA: Well, we -- what we ended up doing, we did have some difficulty. We started out with an automatic welding process and putting this weld back together. And we did find that we -- we had difficulty. And when we did the -- you know, the X-rays, that we couldn't -- we couldn't get clear welds. So we did end up going to a -- basically, a 152 stick weld process.

But the key point -- I mean, the main point is that this process was from the ID to the OD, and that we didn't create this situation that caused the problem back in the early days. It wasn't the weld repair per se. It was what -- what I'm about to show you. It's from the middle of the wall back to the ID.

Here you see the initial weld fit up and configuration. The nozzle, of course, that -- orange is the butter, and then the stainless steel pipe.

Let's go ahead and go to the next one.

So, by design, what is done is you lay these beads in from the ID to the OD. This wall thickness, by the way, is like two and a fifth inches, and there are about 100 passes to get to the ID to the OD. And the design is that as you lay the subsequent weld beads in place and they shrink, they cause a compressive load on the underlying weld beads. And in the end you end up with an ID servicing compression. That's by design.

So we did this. This was the first setup. This is not to scale. I'll show you an actual picture in a minute.

But when we did this we found flaws. And so they ended up going in and grinding all of that out after they laid a bridge in to stabilize the pipe. So they ground it in -- ground it out, and then followed up with -- you can jump on to the next one -- then welded it from the bridge back to the ID. That was the main causal problem. And then they welded it from the bridge to the OD, and we ended up in a configuration like that.

Now, this is -- let's just jump to the --

CHAIRMAN BONACA: Al, you are saying that the crack initiated from the ID. And, therefore, when you were out, looking from the outside, you won't see it.

MR. PAGLIA: That's right. That's right. It's definitely an ID initiative. That's the one.

Now, this picture shows the actual cross-section, and that -- this area down here, which is highlighted here, is the actual weld repaired area that I was showing on that graphic.

CHAIRMAN BONACA: Under the arch.

MEMBER ROSEN: So where is the bridge in this picture?

CHAIRMAN BONACA: Right there.

MR. PAGLIA: It would have been in that area there. It's not visible on this picture, but it was above that -- of the area that was excavated and to be welded.

MEMBER FORD: Just to be sure I understand what you're doing here, is this the original weld repair?

MR. PAGLIA: Yes, sir.

MEMBER FORD: Before the current one.

MR. PAGLIA: Yes.

MEMBER FORD: So this is using, what, 82 -- 182?

MR. PAGLIA: That's correct.

MEMBER FORD: Okay.

MEMBER ROSEN: This was done in what year? 20 years ago?

MR. PAGLIA: Well, it would have been done in the late -- in the '70s.

This was the original -- by the way, and part of that -- this made the first loop weld also, and there was a learning exercise involved here. And that was part of what gave us the situation. We got smarter and didn't have that problem in the other five.

MEMBER FORD: Now, in answer to Dr. Shack's question, are you going to show us what happened when you put in the spool piece, or you tried to do 52 and 152?

MR. PAGLIA: I don't have a graphic that shows that. But what I can -- you know, we put in like, well, I think four or five layers, and then we'd go in and do the -- shoot the welds. And we're basically finding voids. I mean, we're finding imperfections in the weld, and it was ground out, and then it started over.

We never, you know --

MEMBER FORD: Now, you -- I think you said to Dr. Shack that 52 is much worse than 152?

MR. PAGLIA: 52 was used in the automatic welding process, and in that process the -- from a technique standpoint, they were not getting a good weld. And what we ended up doing -- and this was a learning process. Our outages got extended because of these -- our planned long outage got extended because we had to work through this, and then we went manual and solved the problem.

CHAIRMAN BONACA: I thought that under the SER that you used now for the repair, 690 weld material?

MR. PAGLIA: Yes. 690 is the -- is what 152 and 52 is --

CHAIRMAN BONACA: Okay.

MR. PAGLIA: -- is made of. And 82 and 182 is, of course, the 600. So we've got the better materials, and we did -- even with repairs, though, it was an ID to OD. That's the key.

And also we know from stress analysis we have left the ID in a compressive state in the other -- other loop as well. So while it has the original materials, we think we've eliminated really the driver. You take the stress away, you've really eliminated a major piece.

MEMBER SHACK: Now, you didn't mess up the new weld, then.

MR. PAGLIA: No. No, we did not.

VICE CHAIRMAN WALLIS: So what we're looking at here is a cutaway? You actually cut through the --

MR. PAGLIA: Yes, we did. We took out that --

VICE CHAIRMAN WALLIS: -- and that -- so

we're looking at some metallurgical examination of the piece of --

MR. PAGLIA: That's right. This is a slice of the wall cross-section. That's two and a fifth inches here.

MR. LaBORDE: This is the actual carbon steel nozzle. This is the buttering that was done. This is the actual weld material. This is the pipe that --

VICE CHAIRMAN WALLIS: And the failure was somewhere else. This is actually the one that leaked?

MR. PAGLIA: Yes.

VICE CHAIRMAN WALLIS: Is this the place where it leaked?

MR. PAGLIA: No. This is not the actual section.

VICE CHAIRMAN WALLIS: There is no crack shown here in the -- right.

MR. PAGLIA: A different radial location.

VICE CHAIRMAN WALLIS: Right. That's right.

MEMBER ROSEN: So you say you don't have a picture of the crack.

MR. PAGLIA: No, sir.

MR. CLARY: Not with us. We've got it.

We've got a report "yah" thick at home that we sent to NRR that showed the metallurgical evaluation of that, showing the crack.

MR. PAGLIA: What the crack did, it propagated from the ID to the OD, and it progressed through the butter to the carbon steel nozzle and arrested. And that's the extent of it.

MEMBER ROSEN: Can you show me what you mean in this left-hand -- can you roughly trace out what you think the path of the crack was?

MR. PAGLIA: Yes. The crack started in this region down here, and it went up, and it pretty much increased in width, if you will, and it went to this carbon nozzle. Then that cracking stopped at that point, and that was one of the things that obviously confirmed -- there was a lot of other reasons, but that it's TWSCC, which does not act in carbon steel. And then carbon steel stopped it at that point.

MEMBER ROSEN: So how did it -- how did you detect it if it was stopped before it --

MR. PAGLIA: Well, actually, it penetrated in this region right here. And it was like a dome, if you will, to the crack. That penetrated the surface right in this region. The pictures that we have show basically a very small hole. It wasn't a big crack along the pipe; it was a small hole that was the crown of that crack. And that became a small leak that over time created all of the boron deposits that we saw when we went down and did the inspection.

MEMBER ROSEN: Forgive me for not understanding.

MR. PAGLIA: Yes, sir.

MEMBER ROSEN: Can you trace it out one more time? You said it went up to the carbon steel, and then how did it get to the surface from there?

MR. PAGLIA: Well, it -- think of it as a -- it's a crack. It's filling up. It's a planer crack.

MEMBER SHACK: It's an axial crack.

MEMBER SIEBER: Right.

MR. PAGLIA: It's an axial crack. And that was another point -- it was an axial crack. And then, there was a circumferential component, a small circumferential component in this region right here, but not very long.

MEMBER ROSEN: And that's what leaked.

MR. PAGLIA: No, it didn't. It leaked -- it was -- that was embedded. That component was embedded. But where it came through was in this region here, and that was the axial --

MEMBER ROSEN: So the crack was, like my hand, in this plane?

MR. PAGLIA: That's correct.

MEMBER ROSEN: That would be the picture?

MR. PAGLIA: That's correct. And it just hit the surface, and that's where the --

MEMBER ROSEN: Here.

MR. PAGLIA: That's right.

MEMBER ROSEN: It went through the surface.

MR. PAGLIA: But when we did all of the cross-sections, you know, we -- that's when we found out the true crack profile to the metallurgical evaluations that we did.

And, of course, the -- Ron said there's reports like this that show all of the actual metallurgical views of this, and the nature of the cracking, and --

MEMBER ROSEN: Okay. So when it's in this plane, it's axial to the pipe, right?

MR. PAGLIA: That's correct.

MEMBER ROSEN: Which is a good thing to know, and it --

MR. PAGLIA: Yes, that was a positive.

MEMBER ROSEN: Very much a positive.

MR. PAGLIA: That's right.

MEMBER ROSEN: Because axial cracks are less threatening than --

MR. PAGLIA: Yes, sir.

MEMBER ROSEN: -- circumferential.

MR. PAGLIA: Yes, it was.

MEMBER FORD: Now, you said that it went through the wall, you believed, in one cycle? So you went -- an average propagation is --

MR. PAGLIA: Well, I believe so, because this crack was very identifiable, you know, in the outage when we had the -- we went in and, you know, we could see it clearly once we had this throughwall situation.

We did not see anything with the UT outage previous to that. So it could have been -- there's no doubt it was probably there, but it wasn't of significant magnitude. But -- and there's no way to know for sure.

CHAIRMAN BONACA: Although, I mean, one of the things I heard was that one of the beliefs was the sled that the probe was running on may have bumped into a rough surface there on the bottom. Is it --

MR. PAGLIA: Well, that's part of the

improvement of the UT. I mean --

CHAIRMAN BONACA: So it could have been there, but you hadn't seen it.

MR. PAGLIA: It could have been there, and we just didn't see it.

MEMBER ROSEN: So how much boric acid came out? Was there a huge pile?

MR. PAGLIA: There was quite a bit. How many --

MEMBER ROSEN: About 1,000 pounds?

MR. PAGLIA: About 1,000 pounds. It was huge. I mean, when we went in to do the normal walkdown inspections at the outage, it was like, wow. In fact, we really couldn't believe that it was coming from the primer. We thought it may have been some leakage from --

VICE CHAIRMAN WALLIS: Well, that's what we're doing here. I mean, we're not talking about the event at V.C. Summer. We're talking about license renewal.

MR. PAGLIA: Yes.

VICE CHAIRMAN WALLIS: We could be here all day about diagnosing what happened with --

MEMBER SIEBER: This is significant degradation.

CHAIRMAN BONACA: It's a significant issue for this plant and for others, and we wanted to learn something about this, so --

MR. PAGLIA: Okay. So we're going to be --

CHAIRMAN BONACA: -- I think we can move on.

MR. PAGLIA: Okay. The next item was the head inspections that we've done, kind of like, I'll say, the bottom line at this point in refuel 14 -- really, we also -- we went in in 13 as well and didn't see anything, but in 14 we did remove all of the insulation, and went in with remote optical devices, did 100 percent bare metal inspection in the upper head, and at this point we're in pretty good shape. There was no active leaks, obviously, or degradation.

The lower head -- similar. We went in, we did a 360-degree, 100 percent bare metal inspection, and there were no active leaks or degradation. We cleaned it very well, and we've got a video record. And we have a good benchmark for future inspections.

MEMBER ROSEN: Did you choose your words very carefully there? There are no active leaks. Do you mean there have been leaks in the past or --

MR. PAGLIA: Yes, I did. And there was a

leak in the past on the upper head. There was a comma seal leak back in refuel 2. This is where a thermocouple wire -- gets a CM for thermocouple into the drive. And there was a leak, and we had it subsequently in 3. We did a modification in 4, and we haven't had it since. But it wasn't a head -- it was not a head leak.

MEMBER ROSEN: So you went in and found a lot of boric acid on the head from that?

MR. PAGLIA: There was not much, no -- no, sir. There was not much, but there was some.

MEMBER ROSEN: Okay.

MR. PAGLIA: Yes.

CHAIRMAN BONACA: I thought it was coming from the crack that you identified.

MR. PAGLIA: Well, what I was speaking of, again, is the upper head.

CHAIRMAN BONACA: Oh, I see.

MR. PAGLIA: On the lower head, when we went in, we did find some thin film boric acid residue on the lower head. But it was in the radial position of the alpha hot leg, and almost assuredly came down from that leak. And we've cleaned it. And, again, through the inspections primarily, we know we -- we are -- don't have a cracking situation.

We also did -- we also did a chemical analysis on that boron. That boron was 1.9 years old based on some comparisons of cobalt and cesium, and so forth. So we have other bases to believe that that's not active in this -- at least in this cycle, so --

MEMBER SIEBER: Did you compare it to the boron you collected at the -- at the hot leg?

MR. PAGLIA: I'm not sure if we did or did not.

MEMBER SIEBER: That would be a good match to tell you whether it came from there or not.

MR. PAGLIA: But I know that based on the lack of cesium-137, I mean, we knew it wasn't run recently.

MEMBER SIEBER: Yes, right.

MR. PAGLIA: Because if it was, it would be -- it would be new, obviously, because we had just shut down.

So that's where we are on the head. So right now, I mean, we don't have any specific plans, although we know it's probably inevitable that we'll have to do something with the head later. Right now, we're okay. We'll continue to monitor it closely.

Sump blockage bulletin -- we went in in refuel 14, did some inspections, walkdowns per the NEI guidelines. We did identify some original installation gapping, nothing significant. But nevertheless, not meeting the intent or the letter.

The gaps were repaired, if you will. We recovered them in modification. And currently, we're really looking at the sump design. The adequacy of the sump design and the surface area defined in the screen is the issue of concern, and the -- and we are going through that process. We expect to finish that analysis this year.

And if any modifications are required to the sump to increase that, we'll do it in refuel 16, which should close out this issue for -- in accordance with the GSI-191 target time.

Next item I'll talk about a little bit -- and Jamie will speak to this -- and that's the thermal fatigue.

MR. LaBORDE: I'm Jamie LaBorde, and I'm the lead for the primary systems in license renewal.

We have been doing fatigue monitoring for a while. We have been using the WESTEMS process for a little over 12 years now. We do have data, both cycle counting type data and a number of items that we do actual CUF monitoring on.

We have three locations specifically which have been a concern, because of the high usage for 2002. The numbers are up there for 2002 for the normal and alternate charging and surge line. Those locations -- CUFs -- for normal charging is 4.63. Alternate charging is 4.74, and the surge line was 3.78. We do have new numbers for the year 2003, which are not on the slide, but they were for normal charging -- were 4.75, alternate charging is 4.78, and the surge line is 4.14.

And we have projected those out to 40 years using the last 12 years of data, because the first eight years was not as rigorously -- wasn't monitored by the WESTEMS system. And right now that puts our projections at 40 years at -- for normal charging at .836, for alternate charging it puts it over one, and for the surge line it puts it over one. And that's with no allowances for environmental fatigue, and all three of those locations in 60 years are showing right now a trend to go over one at 60 years without any allowance for environmental fatigue.

We have committed to do the 6260 locations for environmental fatigue using the two NUREG curves -- the carbon steel curve and the stainless steel curve. And that is in our -- will be in our FSAR, and it's one of our commitments.

MR. PAGLIA: Okay. Next, Bob Wharton is going to speak to the groundwater.

MR. WHARTON: My name is Bob Wharton. I'm the structural lead on license renewal at Summer Station.

At the subcommittee meeting in December, there was interest shown in discussing our groundwater analysis at this meeting. So what we're presenting here is from our original application submittal in 2002. The results are shown from some old wells, which existed at the plant site at the time that we were developing the license renewal application.

Those results indicated that we had a pH in the 4.8 to 5.3 range, which, according to the NRC criteria or the regulation criteria, is that we should be considered as aggressive groundwater.

Subsequent to the submittal, however, as part of a new site study at Summer Station to evaluate a dewatering concept around the plant site, we've installed 37 new wells through soil borings and establishing some wells in the plant site area.

And the recent analysis which was done in October of 2003 from five of the wells indicated now that the water is non-aggressive. As you can see from the new wells, the pH was in the range of 6.0 to 7.1.

So our later data basically says that we're in a non-aggressive environment, so we just wanted to present that at this point in time.

MEMBER ROSEN: Well, what changed?

MR. WHARTON: The only -- we had old wells which had been in effect -- established for over 15 years, so they were put in originally around our fuel oil storage tanks to monitor any potential leakage that could occur out in the yard area. This is from a state regulatory perspective.

Whether those wells had been contaminated over time, or there was some chemical analysis that took place that could potentially have changed or lowered the pH, we really don't know at that point in time. All we can say now is that we -- we have recent studies.

In talking to the engineer who performed these well studies and establish the wells at the plant site, they went through all of the proper procedures to cleanse the water -- to cleanse the wells to resurge, and then take samples.

So it appears that we have a better quality of sampling that was taken at this point in time. Originally, we just asked people to go out and get some water samples, and so I -- it's hard to distinguish why the pH changed to that level.

CHAIRMAN BONACA: In the SER it is documented that you have no commitment to enhance your program to monitor groundwater. Are you changing that now because of this finding?

MR. WHARTON: No, we are not. We have committed that we will continue to monitor the groundwater every five years, and we're going to do that concurrent with the structural maintenance rule schedule.

CHAIRMAN BONACA: Although during the subcommittee you showed us an interesting picture of another structure close by with similar groundwater characteristics. And, in fact, you are showing that after 70 years it is in good shape, so that --

MR. WHARTON: Yes. Do you want to see that?

CHAIRMAN BONACA: -- is more comforting than --

MR. WHARTON: Would you like to see those -- yes, we have those.

CHAIRMAN BONACA: Yes.

MR. PAGLIA: And also, too, that chemical analysis of the water at this location is also comparable to these results that we got. So another data point for us.

MR. WHARTON: All right. This -- we have a hydro facility located about 18 miles south of Summer Nuclear Station. What we have determined is that the area is in the same geological province. The rock -- underlying rock structure is similar.

The soil profile is very similar, and we actually went and took some analyses at that location and determined that the pH was in the range of roughly seven -- 6.94. Sulfides, sulfates, the chlorides were all very comparable. So we think we had very similar groundwater conditions.

So what we're looking at here is a powerplant that was -- that was established or was constructed in 1930 as part of a large reservoir for hydro production. So in the upper photograph you have the construction in the 1930 timeframe, and in the lower it's from 2003.

You can go ahead and flip through these slides.

The next slide will show you the penstocks coming in to the hydro plant were metal penstocks but they were encased in concrete. And these penstocks were subsequently embedded in the toe of the dam. And as you can see also, the construction activity -- it's a lot of scaffolding, barrels, and so forth.

So when we started a dam remediation project at Saluda Hydro -- yes, the next slide. When we started this project, they did the excavation, and, as it turned out, they found out that all of the old construction materials were left in place. The barrels -- they found everything intact as it was left. It was just buried.

So there were potentially a lot of contaminants, and so forth, and it's -- Saluda Dam is the location. But in the lower photograph from 1930, you can see the concrete encasement of the penstocks. And then, when we excavated in 2003 -- and I visited this location -- the concrete was in remarkable condition, 70 plus years later, being subject to very similar groundwater conditions.

Any more questions on that? Okay. Let's go back to the original slides.

So anyway we did the recent analysis, and I guess we're looking at now approximately --

MEMBER FORD: I'm sorry. Would you kindly go back to that picture? It was a fascinating picture. Is that rust in 2003 at the top of --

MR. WHARTON: No, it's the red clay staining.

MEMBER FORD: Oh, okay.

MR. WHARTON: Yes, red clay staining.

MEMBER FORD: Okay.

MR. WHARTON: That part of the country has a significant amount of red clay.

MEMBER ROSEN: Is that concrete reinforced concrete from --

MR. WHARTON: Yes, it would have been reinforced concrete. But, again, it was from the 1930 vintage. It was, you know, concrete quality, placement techniques, construction techniques.

MEMBER ROSEN: Following Peter's comment, I guess he was trying to figure out whether the --

MEMBER FORD: It was rust.

MEMBER ROSEN: -- whether the rebar was rusting.

MR. WHARTON: Well, in fact, there were no visible cracks seen, no scalding of concrete, no moisture --

MEMBER FORD: I'm not suggesting concrete rusts.

(Laughter.)

MR. WHARTON: That's purely just the staining from the red clay.

Where the corner is is roughly where the grade of the toe of the dam would have encased or been consuming the penstocks.

MEMBER ROSEN: Was this stuff underground water? I mean, it's pretty high up.

MR. WHARTON: It was at the toe of the dam. It was saturated, so it was --

MEMBER ROSEN: Oh. There was water level over the whole --

MR. WHARTON: The dam goes from the pump house back towards us.

MEMBER ROSEN: Okay. So it was all covered in earth.

MR. WHARTON: Yes. It was covered in earth for --

MEMBER ROSEN: And that was the level of the ground right there, the top -- where the penstocks enter the --

MR. LaBORDE: Right. I think about here was the --

MEMBER ROSEN: So it was very close to the surface there.

MR. LaBORDE: Yes, but you can see ground in here.

MR. WHARTON: Since you're in generally a saturated condition at the toe of the dam where it goes back into the river below.

MEMBER ROSEN: Okay.

MR. WHARTON: If there are no more questions on groundwater, our next slide -- the next slide is on surface water pump house. There was interest shown at the last meeting about the settlement of our surface water pump house. And in general, what we observed during the construction of the pump house was excessive settlement. And this was in the 1976 to 1977 timeframe.

As we were building up the embankment, the west embankment, which was where the pump house was constructed, the pump house settled six to seven inches at a point in time which was greatly exceeding our original estimates. So we, at that point in time, accelerated the settlement by loading the pump house, filling it with water, to accelerate whatever maximum settlement would occur.

During that same time, we did a reanalysis, and based on additional soil borings determined that the total projected settlement would be about 12 inches. And that's what it ended up at, so we had a total settlement, very uniform, of about 12 inches.

Since that time, we filled the surface

water pond. We have been monitoring the settlement since 1977/1978 timeframe. So for the last 20-plus years we've shown relative stability within a plus or minus quarter-inch, which is what we had expected to be a seasonable fluctuation. And we're continuing to monitor it to this date.

Any other questions on settlement?

MR. PAGLIA: Okay. On commitment tracking and the living program, as has been verified, we have, of course, loaded all of our commitments into our station tracking system. And we are putting all of the implementation guidance for license renewal in a couple of principle documents, and then, of course, there are a large number of implementing procedures for the programs.

But we're putting together what we're calling a license renewal DBD or design basis document. And it will basically summarize what went on in the application process and point to and reference the underlying basis documents. And this will be a resource feature for engineering folks to use in evaluations of changes.

We're also putting together a station -- for us what we call a station administrative procedure. It's the highest level procedure we have.

It's procedures used that cuts across the entire plant site and affects all organizations. And this procedure will house the direction, if you will, for implementing all of the requirements and commitments of license renewal.

And that main principle procedure will reference all of the individual implementing procedures for all of the programs that we accredited, and they, in turn, will cross-reference this -- this station's stated procedure.

And that's well on its way. That procedure will probably be in the review cycle within the next month. As far as configuration control, just meeting the requirements of staying in compliance with the requirements of 54, part of the procedure revisions that we're doing involve the engineering configuration control procedures. And we will be including steps in there to review future changes against the requirements of 54, and then -- and it will also drive the necessary FSAR updates on the normal update cycle.

That pretty much ends what we had planned to cover. I would say in summary after nearly four and a half years now, I think that we have met all of the requirements of the license renewal rule and the associated guidance documents. And we really appreciate your consideration of the license renewal for Summer Station.

Thank you.

VICE CHAIRMAN WALLIS: Just go back to this last slide. A lot of license renewal is based on commitments from a licensee to do things, which sounds fine, but obviously that's no good without a really good followup to make sure that it really happens.

MR. PAGLIA: And that's the reason why -- and I'll tell you, we have evolved, and I think where we are now is a very strong position. That station administrative procedure, again, is the highest level procedure. It's signed by all of the general managers, and it is our -- our means of causing things to happen.

All changes to that procedure in the future will have to be done under 50.59. When they do that 50.59, our future commitment accountability program will drive them to review that DBD and do the necessary reviews against the licensing basis for renewal.

So that's our programmatic control system, and it's essentially the same system that we use for the CLB. We really aren't doing anything new programmatically, but we are using the highest level procedure we have to capture these LR requirements.

MEMBER ROSEN: Who is in charge of license renewal commitment performance?

MR. PAGLIA: Well, in this case, because -- in this case, because of this level of procedure, okay, all of the organizations -- and assigned, again, by -- normally, a procedure is owned by a department head. This is a procedure that's a level above that. This procedure is owned by all of the four general managers, and they report to the Vice President for Nuclear.

So everybody has a part to play, and those parts are clearly identified in this procedures. As far as you would say the overall tracking of commitments, and so forth, that follows the nuclear licensing organization.

MR. LaBORDE: This is a draft. I don't think Al has even seen this yet. It's still warm. This is a 100 series SAP, which is our station administrative procedure. Because it's a 100 series procedure, this will be signed by the general manager of Nuclear Plant Operations who is the plant manager. And he is ultimately responsible for the things that are in here.

Although the procedure will be written and controlled in effect by the licensing manager, it is the GM of Nuclear Plant Operations or the Plant Manager's procedure responsibility to ensure that this is done.

MEMBER ROSEN: I assume --

MR. CLARY: And I'm the licensing manager, so it's mine.

MEMBER ROSEN: I assume he has something to do other than just worry about license renewal -- the Plant Manager?

MR. LaBORDE: Yes, but --

MEMBER ROSEN: Is there anybody who has --

MR. LaBORDE: This is the level that our procedures have to --

MEMBER ROSEN: Is there anybody who has a full-time job worrying about license renewal, or a significant portion of his time spent on --

MR. PAGLIA: Well, I would say that, frankly, to be honest --

MEMBER ROSEN: Or is it like QA, where you've distributed the function out to everybody?

MR. PAGLIA: It's sort of like everything else. I mean, we -- we committed mostly to existing programs. And we have obviously committed to do some future inspections.

So we are going to continue to implement our existing programs, and the organizations responsible to do that will continue to be responsible. There's really nothing unique that we have to do for license renewal, except in a case where we've got some future inspection activities.

Now those are listed in here, and they are tracked with our tracking program. And they will have due dates, and they will cause actions at that time.

If we went past those, we would be violating this procedure. And it's just typical programmatic control at the plant.

But there's -- you know, there is really -- we have talked about it, to be honest with you. Do we need a single point accountability person, and so forth? I think we will have one, but that role really -- what we're doing is we are going to change the engineering procedures and do training.

And we will have training sessions with our engineering personnel, such that the processes that they need to go through, so that we remain in compliance with 54, will be done on an ongoing basis by those people using their procedures. There's no -- there's not going to be a central -- necessarily a central point that you have to get all the answers from.

Does that address your question or concern?

MEMBER ROSEN: It does. And I think about half of the licensees have taken the position that you've taken. And about half or maybe slightly less than half have taken the position that they needed a station point of contact, someone to --

MR. CLARY: Each SAP has an owner. Okay? And that person owning -- that manager that owns that, okay, is the person who will then drive it through the process to make any changes. It just -- it's such high-level procedure that general managers sign off on --

MEMBER ROSEN: Yes, I understand. And I -- you know, I think that either approach can work. I just was wondering whether or not -- which one you had chosen, and now I know.

MR. PAGLIA: Now, in reality, okay, for a while while we're still around, we -- me is that person. And if questions come up about how we will implement, they will come to this team here to get help. So I think after a few years this becomes embedded in the station, and hopefully a lot sooner than that, frankly. But we are here as a resource.

CHAIRMAN BONACA: Okay. I think if we don't have any additional questions, I think we should turn maybe to the staff. Dr. Raj Auluck will make the presentation.

Thank you for the informative presentation.

MR. PAGLIA: Okay.

MEMBER ROSEN: You may have established some sort of record, too. I think you may be the first licensee who has shown us a picture from -- what was it, how many years ago? 70 years ago?

MR. PAGLIA: Yes.

MEMBER ROSEN: As part of the case for the current --

MR. LaBORDE: I believe the dam -- the construction of the dam was actually completed in 1920.

DR. AULUCK: Good afternoon. My name is Raj Auluck. I am the Project Manager for the review of V.C. Summer's license renewal application. With me is Kimberley Corp, and she is a Project Manager in our License Renewal Group, and she has been helping me in this -- completion of the safety regulation report. You may recall that she made some presentations during the subcommittee meeting on December 3rd.

Caudle Julian, who is the team leader for all of the inspections, I think is on the line. Caudle, are you on the line?

MR. JULIAN: Yes, I am, Raj.

DR. AULUCK: Okay. Thank you. And he's available to respond to any of your inspections in the inspection areas.

Next slide.

This first slide you have seen. As it says, the -- it's a three-loop Westinghouse plant. And one thing to note here is that their current license expires on August 6, 2022, and the application came on August 6, 2002. It is exactly 20 years. That's the earliest any applicant can come, according to the regulations of 54.17. So --

MEMBER POWERS: Yes, sir. But what hour if you submitted --

(Laughter.)

DR. AULUCK: We received them at 8:00 on August 6th.

(Laughter.)

The draft SER was issued on October 9, 2003, and we made the subcommittee presentations on December 3, 2003. Since then, there has been no new technical information exchanges to the SER, since we briefed the subcommittee.

There has been several editorial changes, and corrections have been made to the final document. Comments provided by the applicant, they have been addressed.

Next slide, please.

10 CFR Part 54 says that what needs to be met in order to issue a renewed license. There are basically three requirements as shown on this slide. The first one relates to staff's safety review of the application that we are talking about today, and the second one relates to the environmental impact of the proposed action. And the third one relates to any request for hearing or petitions to intervene on the proposed action. There were no such requests.

Next slide, please.

The staff's review process begins with the review of the applicant's methodology described in the application, and to assure that it meets the requirements of the rule. The staff review is supplemented by an onsite audit to review the detailed documentation available at the site.

There was nothing unusual about that review of this application. The review of scoping and screening results from the applicant has appropriately identified structures and components to be included within the scope of license renewal.

As a result of our review, no new structures were added. Few components were added to the scope of license renewal as a result of our review, and we discussed those at the subcommittee meeting. There were mostly in the fire protection area.

As you know, fire protection is very station-specific, and we do 100 percent review. And there is always a difference of opinion on a technical basis what should be included and what should not be included.

The staff believes that all system structures and components subject to aging management review have been appropriately identified. Again, staff's review of the aging management program was supported by audits and inspections at the site.

As a result of staff review, three new aging management programs were added, and they were all in the electrical area.

Next slide, please.

This one -- this slide gives the -- deals with the timing of audits and inspections. Audits --

by definition, they are used to support NRR staff review activities. Inspections support regional activities and follow set guidance and procedures.

We already talked about our audit inspection for the methodology audit. And the scoping and screening inspection consists of selected examination of procedures and records, and interviews with personnel regarding the process of scoping and screening. These have been the standard procedures we have followed over the last several applications.

Now, as you recall, this was the fourth application which followed the GALL format. And so -- and this was the second one where we conducted onsite audit. These applications contained, for those aging management programs -- which they claimed they are consistent with GALL aging management programs -- they just provide a summary description.

So for this one, we conducted a detailed audit of the plant. We were about five staff members from here, and there were two contractors who wanted to get on the -- you know, the learning curve to follow the inspections later on.

So, and the purpose of this audit was to confirm that a given aging management program, as stated in the application, is consistent with the AMP as described in the GALL report. This was done by comparing the 10 attributes as described in the program basis documents, which are called technical reports in V.C. Summer's case, and they were at the site. And we've got 10 attributes in the GALL report.

In some of the programs, clarifications were needed for completeness and accuracy. All action items, as a result of this audit, were included in a -- it's called condition evaluation report, CER, by the applicant. And this was a part of the tracking system, and we talk about how we did the closure on that CER.

The third -- the aging management program review inspection -- actually, it's the aging management program inspection -- this is conducted by the region. And it follows manual chapter 4516 and NRC inspection procedure 71002.

This inspection did not identify any findings as defined in the NRC manual chapter 0612. The inspection concluded that license renewal activities were conducted as this application, and that documentation supporting the application is in an auditable form.

Though it was -- observation was made that applicant has not yet established a tracking -- for tracking for items, in the planned future task list system we assure implementation of the proposed action to support license renewal.

And we were told that they are in the process of doing that, and in -- in following a couple of months, I'm talking this inspection was done in August, so in October or so we'll be completely finished with that activity. So at that time, we decided, with the region's input and NRR management input, that we should conduct a third inspection.

So the purpose of the third inspection was to -- to look at their tracking system and also our closure out of any other discrimination evaluation report. So that's what was done during the third inspection in November of 2003, and we briefed the committee of the results in December also.

Next slide just gives you a brief overview of total number of aging management programs. The applicant credited 45 aging management programs for license renewal, and they claimed that 34 of these programs were consistent with GALL, and 11 programs were non-GALL programs, site-specific programs.

And 26 of them were existing programs where the -- you know, changing -- when used in the aging management programs, and 16 were new programs, and, in addition, there were three new -- three aging management programs related to TLAAs.

VICE CHAIRMAN WALLIS: Now, when the program is consistent with GALL, your criteria for evaluation would seem to be -- to check that they really are consistent with GALL.

DR. AULUCK: Right.

VICE CHAIRMAN WALLIS: Right? Well, in the non-GALL programs, you have to decide what to do, and you have to figure out what the criteria should then be.

DR. AULUCK: We did not look at any non-GALL programs, because the application contained all of the 10 attributes for the new program, and there were staff at headquarters -- they did a detailed review and wrote the safety evaluation on those programs.

VICE CHAIRMAN WALLIS: I'm trying to remember, because the question arose in my mind when I read your -- the SER, and then it turned out that there was a rather thorough review of the non-GALL programs. But it still wasn't quite clear to me what the criteria are.

You say there are 10 criteria, the 10 --

DR. AULUCK: The 10 attributes in the

GALL --

VICE CHAIRMAN WALLIS: Okay. So there is some consistent basis for evaluation.

DR. AULUCK: Right. It is, right.

MR. LEE: This is Sam Lee. The 10 criteria, as explained, will be primarily what the staff uses for license renewal.

VICE CHAIRMAN WALLIS: So that's really helpful, and you have a procedure and it's clear, and you go through it.

DR. AULUCK: Next slide, please.

This slide I think I had put it here for the completeness. Dr. Bonaca, you already asked the question, "What are you going to do with the conditions we have put in the SER?" And our answer is this -- you know, this is -- we accept what the reserves are. And as time goes on, if those new reserves are established, it will be a decision what to do. But right now those additional provisions would stay in the SER.

VICE CHAIRMAN WALLIS: Okay.

DR. AULUCK: Next slide, please.

MEMBER POWERS: I note that the applicant corrected that slide.

DR. AULUCK: Yes, right. Well, see, those are the -- the new data is not sent to us on a docket, so we do -- yes, so -- and it's for their own use, and --

CHAIRMAN BONACA: This is the SER information. We haven't changed that.

DR. AULUCK: No, we have not changed the SER information. No.

CHAIRMAN BONACA: We will note that.

DR. AULUCK: Next slide, please.

CHAIRMAN BONACA: TLAAs.

DR. AULUCK: The staff review concluded that the applicant has appropriately identified all TLAAs in the application. Actually, one of the RAIs we did ask the applicant to tell us that other TLAAs which are identified in the -- you know, the GALL are -- not the GALL, I think in the SRP are not applicable to the V.C. Summer site. So they responded that -- they assured us that they have included all of the applicable TLAAs.

And, again, for completeness, we have included the slide for reactor vessel improvement results. The first one shows upper shelf -- these are the various screening criteria, as the staff calculated values. It got very close to the applicant's values also.

I just wanted to add that during the last outage, which was in November, they have taken one condition capsule out, and they have been -- one capsule has been removed and will be tested and will provide the bounding data for the end-of-life values, and they will --

CHAIRMAN BONACA: These are end-of-life calculated values, right? This is end of 60-year life.

DR. AULUCK: Yes. Right. They are confirm that -- if there are any changes from the current results. So that will be new --

CHAIRMAN BONACA: What you put up there is --

DR. AULUCK: It's 60 years.

CHAIRMAN BONACA: Yes.

DR. AULUCK: It's 60 years.

MEMBER POWERS: How many capsules does the licensee have to extract over the next four years?

DR. AULUCK: They have two left, one that -- they are taking it out now. The next one they're going to take out in refueling outage 15, and then put it in storage for future use.

MEMBER POWERS: And so after that they will have no more capsule?

DR. AULUCK: No, they will -- except the one in storage for future use. If they want to put it back there --

MR. ELLIOT: This is Barry Elliot, Materials and Chemical Engineering Branch. We have a gold program for capsules, and our direction is that we want one capsule to be withdrawn at a fluence equivalent or slightly greater than the 60 years fluence for the vessel ID. And that would be the capsule -- the last capsule that they're going to withdraw.

Our other direction is if you have other -- additional capsules, to take them out early in a plant's life, like now, before they gain too much fluids, beyond the 60 years, so that if -- if the plant decides to go for another 20 years, they can reinstall those capsules and they will have -- they can start generating a fluence.

The leak factor for this plant is on the order of three. So that if we leave the capsules in, they could gather -- by year 60, they would gather 180 years of fluence and be useless. It's a good idea to take them out.

MEMBER POWERS: We love those broken things that are totally useless.

(Laughter.)

MR. ELLIOT: I understand.

MEMBER ROSEN: What did you say about another 20 years beyond the 60 years?

MR. ELLIOT: Yes. In other words, if they wanted to go another 60 -- 20 years past the 60, they could take the capsules that they've taken out, reinsert them sometime in the future, and gather more fluence.

MEMBER ROSEN: Wait a minute. I didn't even know that there was such a process involved -- available.

MEMBER POWERS: There is no limit.

(Laughter.)

MEMBER ROSEN: You mean these plants are immortal.

MEMBER POWERS: He didn't say the plants were immortal. But if they are immortal, they can go forever.

(Laughter.)

CHAIRMAN BONACA: Right. The only thing you know is that this committee won't be here at that time.

(Laughter.)

MEMBER ROSEN: No. On the contrary, I

think the committee will be -- yes, Dr. Kress will be, but the members may be different.

CHAIRMAN BONACA: Well, no, I said these people are -- they won't be here.

MEMBER SHACK: Barry, why don't you just leave the next capsule in until it hits 80 years worth of life, and then haul it out?

MR. ELLIOT: That's an alternative that they can -- they can decide. I mean, we don't tell them to take it out at 60.

MEMBER SHACK: Oh, I thought you said we just --

MR. ELLIOT: No, no, no. We say -- we recommend you take it out sometime --

MEMBER POWERS: I really like the strategy you've set up better than leaving it in to 80, because you have no guarantee that over the next 20 years we won't change Logan patterns, and things like that.

MR. ELLIOT: Well, we also have criteria that they have to establish for fluence, in that they have to have -- maintain a certain fluence level, and also have a extensive dosimetry program, so that if they do change the loading pattern we'd be able to determine what the impact of the new loading pattern is on the fluence.

MEMBER POWERS: Because your information on the vessel is so comprehensive and complete, there's hardly a thing to research anymore.

(Laughter.)

CHAIRMAN BONACA: All right. So there's a lot of margin there.

MEMBER ROSEN: Yes. We commented earlier to the licensee that they had a lot of margin, and this one has even more.

DR. AULUCK: I think the copper content is very low.

MEMBER POWERS: It's not low enough to keep us from researching copper, though.

DR. AULUCK: The next one I think is related to metal fatigue. I think it's, again, a repeat from what the applicant has put -- the applicant's analysis indicates that three components which make the design basis fatigue usage factor during a period of extended operation --

CHAIRMAN BONACA: Those are the charging --

DR. AULUCK: Charging nozzle and surge line reactor coolant loop nozzle. And they will have to take corrective actions, and the corrective actions include more regressive analysis of the component to demonstrate that design code limit will not be exceeded, repaired, or replace part of the component.

The next one --

MEMBER SHACK: So at the moment he's tracking transients, but he's still using his old-fashioned stress analysis. So he can still go back and sharpen the pencil?

DR. AULUCK: That's the options.

The next slide is a commitment tracking system. And we have mentioned earlier that they have put most of these action items, commitment items, in the tracking system. Appendix A of the SER lists all of the license renewal commitments.

In doing a thorough inspection of the site, staff verified that all of these have been entered into the station tracking system. Completion of these actions will be confirmed by the staff with the inspection procedure 71003.

The next slide talks about license conditions. As a result of our review, no new plant-specific license conditions have been included.

Two standard licensing conditions are given on this slide. The first one is applicant will include the UFSAR supplement in the next update of the FSAR. And the second one is that future inspections accurately identified in the supplement will be completed prior to the PRA standard operation.

And as a note of information, the final environmental impact statement was issued last week on February 27th.

And that -- it comes down to the conclusions here. Staff has completed its review, and, you know, will prepare -- based on your recommendation, we will prepare the renewed license.

Again, I would like to thank the ACRS for moving the full committee meeting forward two months. You know, it saves us a lot of time, and we are -- and we really appreciate that. Of course, this was possible with the cooperation of -- a good effort from our technical staff, and the applicant, and we had -- you know, everybody pushed to, you know, a meeting of the minds and resolved the issues.

We had issues like any other application, so maybe more than others, but, you know, everybody worked hard to resolve the issues.

And, again, I'd like to personally thank the members. This is my sixth visit here in the last two and a half years.

CHAIRMAN BONACA: Okay. Very good. Any questions for Mr. Auluck?

MEMBER ROSEN: You're getting good at this, Raj.

CHAIRMAN BONACA: Yes.

DR. AULUCK: Well, you can't do any better with no open items.

MEMBER ROSEN: You presented the PTS and upper shelf energy data in the way we like to see it.

DR. AULUCK: Thank you.

CHAIRMAN BONACA: So we want to thank the applicant for a good application and staff for a good review. And with that, if there are no further comments, we will take a recess until five of 3:00.

(Whereupon, the proceedings in the foregoing matter went off the record at 2:37 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: Advisory Committee on Reactor Safeguards

510th Meeting

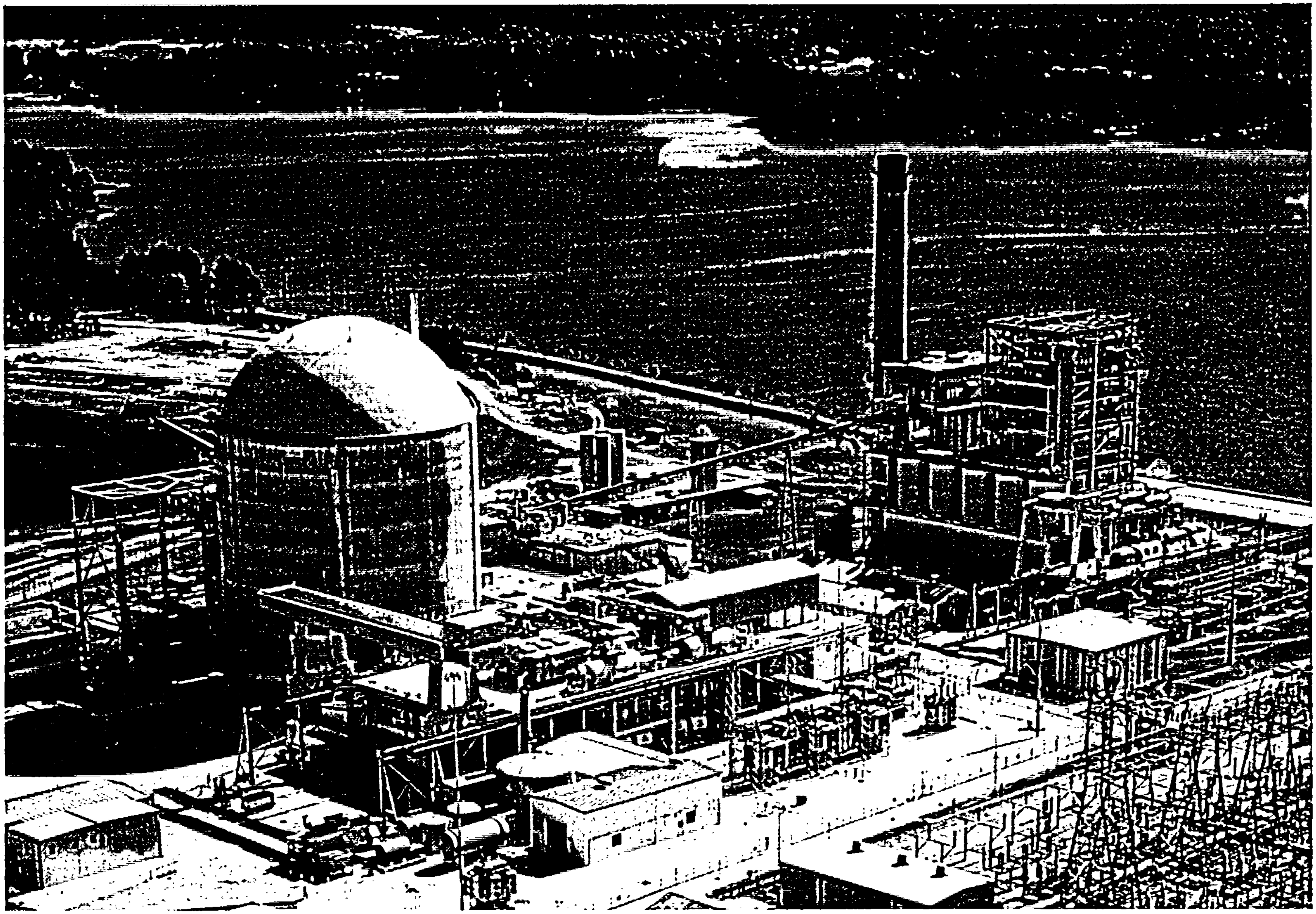
Docket Number: n/a

Location: Rockville, MD

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.

Rebecca Silberman

Rebecca Silberman
Official Reporter
Neal R. Gross & Co., Inc.



ROBINSON NUCLEAR PLANT

ACRS MEETING

March 4, 2004

Progress Energy

RNP Unique Differences

- Robinson Site Consists of a Fossil Plant (Unit1) and a Nuclear Plant (Unit 2)
- RNP Containment-
  - Grouted Tendons
  - Liner is Insulated (Limit Heat Transfer during postulated DBA)
- 480 Volt Emergency Power (versus 4160 volt)
- Safe Shut Down Diesel (in addition to 2 Emergency Diesel Generators)

Progress Energy

Major Equipment Replacement/Upgrade

Within Past 20 Years-

- Steam Generators Replaced (1984)
- Service Water Piping Replaced
  - Inside containment (1988)
  - From booster pumps to containment (1990)
  - North Header (1999)
- Turbine Rotor Replaced (LP 1987, HP 2002)
- Power Uprate (Appendix K, ~ 2% in 2002)
  - No current plans for additional uprate

Progress Energy

Major Equipment Replacement/Upgrade

Ongoing or Planned

- Security Upgrades (4Q04)
- RV Head Replacement (RO 23, Fall 2005)
  - RNP Request for relief from NRC Order related to RV Head Inspection withdrawn.
- Dry Fuel Storage (Load 1st Module 3Q05)
- Generator & Exciter Refurbishment (RO 24)

Progress Energy

Operating Experience

	2000	2001	2002	2003	2004
Capacity	103.96	92.18	93.70	103.54	(2/23) 105.88 (proj.) 95.14
Refuel	NA	4/7 to 5/12	10/12 to 11/14	NA	28 day plan- April 20
Exposure (REM)	8.4	124.8	110.6	4.8	(Goal) < 9 Plus RO22

Currently, continuous run of 465 days*. Breaker to Breaker operation between spring 2001 and fall 2002 refueling. Other offline, minimal:

- 6/21/00 to 6/22/00 Manual Trip due to Turbine EH oil leak
- 11/24/02* Turbine taken offline to repair steam leak

All NRC Performance Indicators are Green

Boric Acid Program

(reference - 06/03 AMR Inspection Report and 09/30 ACRS subcommittee meeting)

- Corporate *"Boric Acid Corrosion Control"* Program has been implemented at Progress Energy PWRs. Procedure guidance includes

  "*All plant personnel should recognize borated system leakage, understand its significance, and initiate corrective action when boric acid residue is detected.*"

  "*If carbon and low-alloy steel components are exposed to boric acid, the components shall be carefully cleaned and visually inspected.*"

Boric Acid Program

- RNP System Walkdown Procedure revised to include

  "*Boric acid corrosion of carbon steel components can adversely impact component integrity. When boric acid leakage is detected, initiate a work request and/or condition report as appropriate to be evaluated in accordance Boric Acid Corrosion Control Program*"

Progress Energy

Commitments/Tracking

- 47 Programs credited for License Renewal. 10 are existing programs and require no changes. 37 Commitments for 27 Enhancements and 10 New Programs have been entered into RNP Commitment Tracking Program
- All Commitments will be either implemented or "transitioned" from LR to Plant Organization for future implementation by July 2004
- The RNP Supervisor of Licensing/Regulatory Programs has overall responsibility for management of commitment tracking

Progress Energy

Commitments/Tracking

- Once Implemented
  - Commitments are identified in implementing documents
  - Change controlled by 10 CFR 50.59 process
- Configuration control process will incorporate guidance to ensure that requirements of 10 CFR 54.37(b) are met; Support by
  - License Renewal Training (October 2004)
  - License Renewal DBD (July 2004)
  - UFSAR Supplement (October 2004)

Progress Energy

V C Summer Nuclear Station

ACRS Presentation

Al Paglia

Jamie LaBorde

Bob Whorton

Purpose

- Background/History
- Application
- Issues of Interest:
  - Hot Leg Crack
  - Head Inspections
  - Sump Blockage Bulletin
  - Thermal Fatigue
  - Ground Water Issues
  - SWPH Settlement
- Commitment Tracking/Living Program

Background/History

- 1000 MWe 3 Loop Westinghouse PWR
- Initial License granted August 6, 1982
- SCE&G is 2/3 owner and licensee
- Santee Cooper is 1/3 owner
- Steam Generator Replacement – 1994
- Up-rate 2775 MWt to 2900 MWt – 1996
- NRC Indicators and Findings all Green

Application

- Application developed in accordance with Regulatory Guide 1.188, utilizing guidance from NEI 95-10
- Format in accordance with NUREG 1800, Standard Review Plan, with comparisons to NUREG 1801, GALL, as appropriate

Hot Leg Crack

- "A" Hot Leg weld replaced with a spool piece utilizing Alloy 690 weld materials
- Root Cause of crack attributed to high residual stresses resulting from original installation weld repairs
- NDE results of all other loop nozzle welds showed no recordable indications

Head Inspections

- Upper Head
  - RF-14 – 100% bare metal inspection
- Lower Head
  - RF-14 inspection – 360 degree 100% bare metal
- No Active Leaks or Degradation

Sump Blockage

- Sump inspections RF-14
  - Original installation gaps
  - Level instrument replacement gaps
- Future Plans
  - Evaluate current sump design\surface area
  - Modification (if necessary) within NRC established schedule for GSI-191

Thermal Fatigue

- WESTEMS utilized for cycle counting including high usage components
- The year 2002 CUF for the Pressurizer surge line is 0.38
  - Changes made to operating procedures to slow accumulation of usage on surge line nozzle
- Year 2002 CUF for the normal charging line is 0.46 and the alternate charging is 0.47
- VCS committed to re-compute the CUF for NUREG/CR-6260 locations using guidelines of NUREG/CR-6583 and NUREG/CR-5704

VCSNS Groundwater Evaluations

- Groundwater initially identified (2002) as "mildly acidic, but non-aggressive"
- Recent analyses (October 2003) from 5 new wells indicate that groundwater is "non-aggressive" – thus minimal effects on buried components

	pH	Cl	SO4
Old Wells	4.8 – 5.3	< 10 ppm	< 10 ppm
New Wells	6.0 – 7.1	< 25 ppm	< 185 ppm
NUREG-1801 (GALL)	< 5.5	> 500 ppm	> 1500 ppm

Service Water Pump House & Intake Structure Settlement

- Excessive settlement observed during initial construction
- Subsequent re-analysis revised projected settlement & rebound estimates
- Settlement monitoring conducted semi-annually
- Results show stability for last 20+ years

Commitment Tracking/Living Program

- All commitments and associated action items have been entered into the station tracking program
- Commitment implementation guidance being incorporated into a License Renewal Design Basis Document and Station procedures
- Configuration Control processes will incorporate guidance to ensure continuing compliance with requirements of Part 54

QUESTIONS

ACRS License Renewal Full Committee

V.C. Summer Nuclear Station
License Renewal Application

Final Safety Evaluation Report
March 4, 2003

Rajender Auluck
Senior Project Manager

Overview

- Application submitted by letter dated August 6, 2002
- Westinghouse pressurized water reactor
- Plant located in Fairfield County, South Carolina
- Current license expires August 6, 2022 - Requests renewal through August 6, 2042
- Draft SER issued October 9, 2003
- ACRS License Renewal Subcommittee meeting held on December 3, 2003
- Final SER issued January 29, 2004

Staff Conclusions

The Applicant has met the requirements for license renewal, as required by 10 CFR 54.29:

- Actions have been identified and have been or will be taken such that there is reasonable assurance that activities will continue to be conducted in the renewal term in accordance with the current licensing basis
- The applicable requirements of 10 CFR Part 51 have been satisfied
- Matters raised under 10 CFR 2.758 have been addressed

Scoping and Aging Management

- Scoping and screening methodology is adequately described and justified in the LRA and satisfies the requirements of 10 CFR 54.21(a)(2)
- Scoping and screening review results found that the SSCs within the scope of license renewal have been identified, as required by 10 CFR 54.4(a) and those subject to an AMR have been identified, as required by 10 CFR 54.21(a)(1)
- Aging management review found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3)

Scoping and Aging Management

Audit and Inspections

- Scoping and Screening Methodology Audit
  - January 28-31, 2003
- Scoping and Screening Inspection
  - May 12-16, 2003
- Aging Management Program Audit
  - July 16-17, 2003
- Aging Management Review Inspection
  - August 4-8, and August 18-22, 2003
- Third Inspection
  - November 19-20, 2003

Aging Management

Aging Management Programs

- 45 AMPs credited for license renewal
  - 34 AMPs are consistent with GALL
  - 11 AMPs are non-GALL programs
  - 26 AMPs – Existing Programs
  - 16 AMPs – New Programs
  - 3 AMPs – TLAA Programs
- 3 AMPs added as a result of staff review

Aging Management

Aging Management of In-Scope Inaccessible Concrete

	Aggressive Limit	V.C. Summer
pH	<5.5	4.8 - 5.3
Chlorides	>500 ppm	<10 ppm
Sulphates	>1500 ppm	<10 ppm

- Applicant has initiated additional site groundwater studies.
- Additional provisions to be added to existing plant programs and procedures.

TLAAs

- The applicant has identified the appropriate TLAAs and had demonstrated or is committed to demonstrate that the TLAAs:
  - Will remain valid for the period of extended operation
  - Have been projected to the end of the period of extended operation, or
  - The aging effects will be adequately managed for the period of extended operation

TLAAs

Reactor Vessel Upper Shelf Energy (USE)

Reactor Vessel Beltline Material	Screening Criteria USE FT-LBS	Staff Calculated USE FT-LBS
Limiting Beltline Plate Material	≥ 50	53
Limiting Weld	≥ 50	59

Pressurized Thermal Shock

Limiting Beltline Material	RT_{PTS} Criterion (°F)	Staff Calculated RT_{PTS} (°F)
Base Metal Intermediate Shell Plate A9154-1	≤ 270	158
Axial Weld 4P4784	≤ 270	110

TLAAs

Metal Fatigue

- Reactor coolant system components at V.C. Summer designed to Class 1 requirements of the ASME Code.
- Three components may exceed the design basis fatigue usage factor during the period of extended operations.

Commitment

- Transients will be tracked by Thermal Fatigue Management Program (TFMP)
- Perform evaluation of NUREG/CR-6260 components for environmental fatigue prior to the period of extended operation
- Components with CUFs projected to exceed 1.0 will be either re-analyzed or replaced prior to exceeding cycles of transients tracked by TFMP

Commitment Tracking System

- SER Appendix A lists the applicant's license renewal commitments
- Fulfillment of commitments will be confirmed by the staff with Inspection Procedure 71003
- Commitments are tracked using the station tracking program
- Implementation guidance being incorporated into a License Renewal Design Basis Document and Station Procedures

License Conditions and Environmental Review

- Two standard license conditions:
  - Following issuance of the renewed license, the applicant will include the UFSAR Supplement in the next UFSAR update, as required by 10 CFR 50.71(e)
  - Future inspection activities identified in the UFSAR Supplement will be completed prior to the period of extended operation
- No new plant-specific license conditions
- Staff's environmental evaluation documented in NUREG-1437, Supplement 12, published on February 27, 2004

Staff Conclusions

The Applicant has met the requirements for license renewal, as required by 10 CFR 54.29:

- Actions have been identified and have been or will be taken such that there is reasonable assurance that activities will continue to be conducted in the renewal term in accordance with the current licensing basis
- The applicable requirements of 10 CFR Part 51 have been satisfied
- Matters raised under 10 CFR 2.758 have been addressed

H.B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2

License Renewal
Safety Evaluation Report

Staff Presentation to the ACRS
SIKHINDRA (S.K.) MITRA
Project Manager
March 4, 2004

Background

- JUNE 14, 2002: CP&L SUBMITTED LICENSE RENEWAL APPLICATION
- SEPTEMBER 30, 2003: ACRS SUBCOMMITTEE BRIEFING ON SER /OI
- JANUARY 20, 2004: SER ISSUED
  - REQUREMENTS OF PART 54 HAVE BEEN MET
- CURRENT LICENSE EXPIRES JULY 31, 2010
- REQUEST LICENSE RENEWAL THROUGH JULY 31, 2030

NRC Audits and Inspections

- **THREE INSPECTIONS AND TWO AUDITS**

- **SCOPING AND SCREENING METHODOLOGY AUDIT**
  - **SEPTEMBER 17 - 20, 2002**

- **SCOPING AND SCREENING INSPECTION**
  - **MARCH 31 – APRIL 4, 2003**

- **AGING MANAGEMENT PROGRAM AUDIT**
  - **MAY 28 – 29, 2003**

- **AGING MANAGEMENT INSPECTION**
  - **JUNE 9 – 14 and JUNE 23 -27, 2003**

- **FINAL INSPECTION**
  - **SEPTEMBER 9 – 10, 2003**

Aging Management Program Audit

OBJECTIVE: REVIEW AMPs CONSISTENCY WITH GALL

- DATE OF AUDIT - MAY 28-29, 2003
- AUDIT REPORT DATED AUGUST 12, 2003
- AUDITED ALL THE ATTRIBUTES OF THE AMPs CLAIMED TO BE CONSISTENT WITH GALL
- CONCLUDED AMPs WERE CONSISTENT WITH GALL EXCEPTING:
  - NON-EQ INSULATED CABLES AND CONNECTIONS PROGRAM LACKED DETAIL TO CONCLUDE CONSISTENCY WITH GALL
    - AMP WAS REVISED AND SUBMITTED TO TECHNICAL STAFF FOR REVIEW
    - STAFF FOUND IT ACCEPTABLE

Aging Management Inspection

- OBJECTIVE: VERIFICATION OF THE ACCURACY OF THE APPLICATION IMPLEMENTATION WITH REGARD TO AMPs
- CONDUCTED JUNE 9–27, 2003
- OBSERVATION:
  - INCOMPLETE INTEGRATION OF FUTURE TASKS INTO ESTABLISHED SITE ACTION REQUEST TRACKING SYSTEM
- INSPECTION REPORT (50-261/03-09) ISSUED ON July 31, 2003

Aging Management Inspection (Continued)

- THIRD (OPTIONAL) INSPECTION
- CONDUCTED SEPTEMBER 9-10, 2003
- APPLICANT HAD LOADED FUTURE TASKS INTO ESTABLISHED SITE ACTION REQUEST TRACKING SYSTEM
- TRANSITION PLAN FOR COMPLETION OF LICENSE RENEWAL PROJECT WAS ESTABLISHED
- INSPECTION REPORT (50-261/03-11) ISSUED ON SEPTEMBER 29, 2003

Open Items

- TWO OPEN ITEMS AND THIRTY CONFIRMATORY ITEMS ALL OPEN AND COMFIRMATORY ITEMS ARE RESOLVED
- Open Item 2.3.1.6-1
  - STAFF IDENTIFIED THAT DEGRADATION OF THE FEEDRINGS, J-NOZZLES, OR J-NOZZLE WELDS COULD PRODUCE LOOSE PARTS INSIDE THE STEAM GENERATOR SHELL
    - MAY DAMAGE SAFETY-RELATED COMPONENTS, ESPECIALLY DURING TRANSIENTS
  - COMPONENTS BROUGHT INTO SCOPE AND OPEN ITEM IS RESOLVED

Open Items (continued)

- ## Open Item 2.3.3.8-1
  - **FOLLOWING A LAKE ROBINSON DAM FAILURE AND DEPLETION OF CONDENSATE STORAGE TANK INVENTORY, FAILURE OF DEEPWELL PUMPS WOULD CAUSE FAILURE OF THE SAFETY RELATED AUXILIARY FEEDWATER SYSTEM AND PREVENT THE RESIDUAL HEAT REMOVAL NECESSARY TO MAINTAIN A SAFE SHUTDOWN CONDITION**
  - **THREE DEEPWELL PUMPS, ASSOCIATED PIPING, AND VALVES WERE BROUGHT INTO SCOPE AND OPEN ITEM IS RESOLVED**

RESOLUTION OF CONFIRMATORY ITEM 4.6.4 .1 - AGING OF BORAFLEX

- LICENSE AMENDMENT WAS SUBMITTED TO ELIMINATE CREDIT OF THE BORAFLEX PANELS FROM RNP TECHNICAL SPECIFICATIONS

- STAFF REVIEWED THE AMENDMENT APPLICATION AND APPROVED THE APPLICANT REQUEST

- DOCUMENTED IN LICENSE AMMENDMENT 198, ISSUED ON DECEMBER 22, 2003, AND SER SECTION 4.6.4

TLAA - REACTOR VESSEL NEUTRON EMBRITTLEMENT

- Analysis of PTS projected to end of PEO
- Staff performed independent calculations

ITEMS	LIMIT (°F) (MAXIMUM)	RNP (°F)
CIRCUMFERENTIAL WELDS	300	275
PLATES/FORGINGS/AXIAL WELDS	270	235

PTS = Pressurized Thermal Shock

PEO = Period of Extended Operation

REACTOR VESSEL UPPER SHELF ENERGY (USE)

- ANALYSIS OF USE PROJECTED AT THE END OF PEO
- STAFF PERFORMED INDEPENDENT CALCULATION

REACTOR VESSEL UPPER SHELF ENERGY (USE)	LIMIT (MINIMUM) FT-LBS	RNP FT-LBS
WELDS/FORGINGS	50	56
PLATE MATERIALS	42 (EMA)	45
NOZZLE FORGING	50	53
NOZZLE WELDS	50	52

EMA = Equivalent Margin Analysis

AP1000 Status

March 4, 2004

ACRS Full Committee Meeting

John Segala, Senior Project Manager
Office of Nuclear Reactor Regulation

Overview

- Purpose
  - Provide status of the staff's review
  - Discuss major schedule milestones
  - Provide overview of remaining Draft SER open items
- Conclusion
  - On schedule to issue Final SER by September 13, 2004

AP1000 Review Chronology

- March 2002 - Completed pre-application review
- March 28, 2002 - Westinghouse (W) submitted DC application
- June 25, 2002 - NRC accepted the application for docketing
- June 16, 2003 - NRC issued DSER with 174 Open Items
- FSER Review Progressing

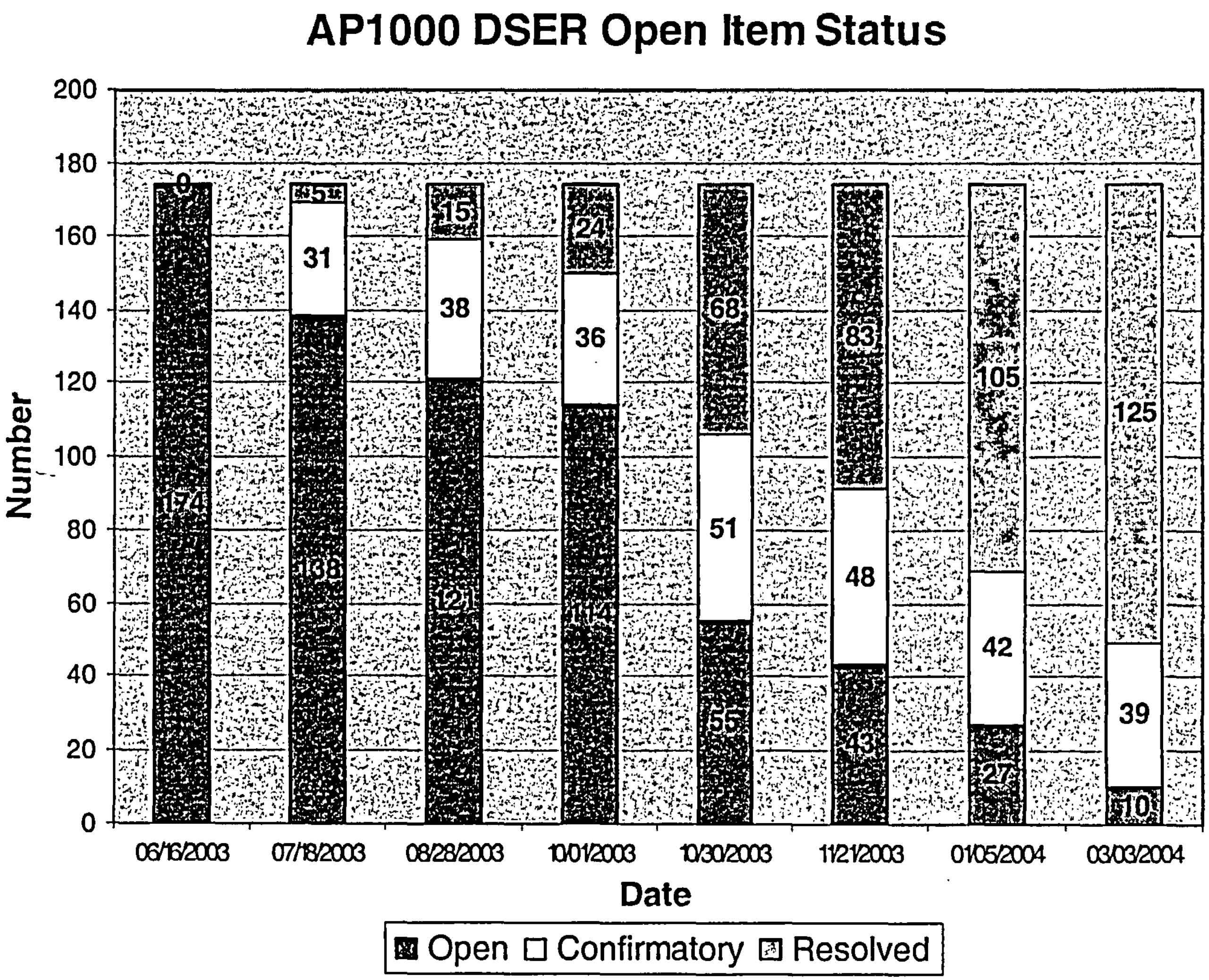
Schedule Milestones

- March 31, 2004 - W provides acceptable responses to all open items
- May 25, 2004 – No Open Item FSER to ACRS
- May 31, 2004 - W submits final AP1000 design control document
- June 25, 2004 - ACRS Future Plant Design Subcommittee Meeting
- July 7-9, 2004 - Full ACRS Committee Meeting
- September 13, 2004 - Final SER and FDA issued

AP1000 DSER Open Item Resolution

Working to Resolve Open Items

- 10 open
- 164 technical resolution completed



Remaining Open Items

- Security (2 Open Items)
  - New COL Action Item
    - Deferred Security Plan to the COL applicant
  - Staff is currently reviewing the ITAAC

Remaining Open Items (Continued)

- Aerosol Removal Coefficients (3 Open Items)
  - Need to determine if AP1000 Removal Coefficients are applicable
  - Sandia National Laboratory Contract
    - Monte Carlo uncertainty analysis
    - 200 runs of MELCORE for DEDVI line break
    - Removal Coefficient over time
  - Staff currently reviewing draft report
  - Staff will run independent dose calculations with W and Sandia's Removal Coefficients

Remaining Open Items (Continued)

- Leak Before Break (1 Open Item)
  - W using LBB for Main Steam piping
  - AP1000 does not have a diverse means of detecting main steam line leakage

Remaining Open Items (Continued)

- NRC Open Items (4 Open Items)
  - Review of final AP1000 Design Control Document Revision
  - Review of Tier 2* information
  - Review of COL Action Items
  - Documentation of AP600 FSER information

Conclusion

- On schedule to issue Final SER by September 13, 2004

- Questions/Comments?

United States Nuclear Regulatory Commission

AP1000 Thermal-Hydraulics Design Review

Presented to
The Advisory Committee on Reactor Safeguards
March 4, 2004

By
Jennifer L. Uhle, Chief
PWR Systems
Reactor Systems Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

Outline

- NRC Review Team
  - Steve Bajorek (RES)
  - Gene Hsii
  - Walt Jensen
  - Lambros Lois
  - Summer Sun
  - Len Ward
- .Review Question
- Open Items and Independent Analyses
- Westinghouse Safety Basis
- Conclusions

Review Question

- NRC performed a design review of the AP1000
  - Relied on work performed for the AP600
    - → RELAP5 code adequacy assessment
    - → Focused review on phenomena that were more important in the AP1000
      - Level swell
      - Entrainment
        - Upper plenum
        - Hot leg
- NRC did not perform a code acceptance review of NOTRUMP and WCOBRA-TRAC
  - Identified code deficiencies were handled by performance of bounding calculations to demonstrate margins in the design
    - → 10 CFR 50.46 for LOCAs
      - 2200 F, oxidation limits and maintenance of coolable geometry
  - All components of the safety demonstration comprise the "Evaluation Model" and must be repeated by future licensees

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Open Items and Independent Analyses

- 12 questions posed by ACRS at the July 2003 meeting
  - Staff and Westinghouse resolved the issues in the course of the review
- Open Items
  - Scaling of APEX
  - Identification of limiting transient
  - Backpressure assumption
  - Early phase collapsed liquid level (CLL)
    - → Level swell
    - → Entrainment (Upper Plenum and Hot Leg)
    - → ADS-4 pressure drop
  - NOTRUMP/RELAP5 comparisons
  - Long-term cooling CLL
  - Boron precipitation
- Independent analyses

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APEX-1000 Scaling and Testing Background

- APEX-AP600 Scaling for AP1000 Applicability
  - Top-down scaling identified minor distortion in APEX-600 in early portion of ADS4 blowdown
  - SPES found to be adequately scaled for AP1000 up to & including ADS4 blowdown
  - Upper plenum (UP) entrainment was distorted non-conservatively
  - Hot leg entrainment not adequately scaled

- APEX was modified to represent AP1000 and tests conducted in APEX-1000 facility in 2003

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APEX-1000 Scaling Review

- Independent top-down scaling evaluation performed by NRC for ADS4 blowdown and transition to IRWST injection.

- Specific evaluation for downcomer mass using test data

- Verification of UP entrainment using test data

- Independent bottom-up scaling for hot leg entrainment

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Summary of APEX-1000 Experimental Observations

- Design-basis showed
  - No core uncovery or cladding heat-up; two-phase levels near or above bottom of hot leg
  - Higher entrainment than AP600 tests
  - Less margin than in AP6000
- Beyond-design basis tests
  - Failure of 2/4 ADS4 valves cause core uncovery
  - Entrainment to ADS4 continues even when UP two-phase level drops to UCP.

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Downcomer Scaling

- Downcomer excess mass is a concern only in tests where DVI stops and downcomer inventory supplies coolant to core
- Effect estimated with a test with a 300 second gap between CMT empty and IRWST injection times
- Excess mass represented ~8% of total vessel inventory, which if removed would lower vessel level less than 5 inches
- Conclusion: Excess mass delays time of core uncovery, but not enough to perturb transient such that the data are not useful for code assessment

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Upper Plenum and Hot Leg Entrainment Scaling

- Upper Plenum
  - UP design accounted for entrainment and de-entrainment using best-available correlations.
  - Post-test evaluation of experimental results shows reasonable agreement between test data and Kataoka-Ishii predictions
  - UP in APEX-1000 is considered to be adequately scaled
- Hot Leg
  - APEX-1000 preserves (d/D) and (L/D) ratios and scales adequately with ATLATS derived correlations for entrainment onset
  - Scaling for HL entrainment considered adequate
    - → High uncertainty in prediction of HL processes is recognized

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Scaling Conclusions

- APEX-1000 adequately scaled to AP1000 for ADS4 blowdown and transition to IRWST injection
- APEX-1000 provides a reasonable approximation of global, system-wide processes and event progression in the full scale plant
  - Adequate for code assessment
  - Cannot prove that no heat up is expected for AP1000
    - → Code calculations are required

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Open Issues (cont.)

- Limiting Transient
  - DEDVI was verified to be the limiting transient
    - → Loss of ½ injection capacity
    - → Independent verification
      - RELAP5 calculations
      - Review of appropriate scaling factor for all transients using code calculations indicate that entrainment is maximized for the DEDVI
- Backpressure
  - NRC reviewed Westinghouse's evaluation of backpressure and proposed more conservatism
  - Westinghouse followed this guidance to set backpressure
- RELAP5 Independent Analysis
  - RELAP5 showed lower CLL than NOTRUMP
  - Differences between NOTRUMP and RELAP5
    - → Interfacial drag
    - → Downcomer modeling and condensation
  - In a sensitivity study, W demonstrated that the overprediction did not result in higher CLL later in the transient and did not rely on CLL as the figure of merit during the period of overprediction
    - → Not an issue

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Westinghouse Safety Basis

- Deficiencies in modeling are accommodated by conservatism and alternative figures of merit.
- Evaluation Model Definition
  - NOTRUMP run in Appendix K mode (AP600)
    - → ADS-4 blowdown
      - CLL is over-predicted by NOTRUMP
        - Downcomer modeling and subcooling
      - Safety ensured by heat transfer
        - heat flux for hot rod compared to critical heat flux
        - Ensured that overprediction does not affect CLL in later stages
    - → IRWST transition phase
      - NOTRUMP entrainment model is deficient
      - Safety ensured by bounding calculation
        - NOTRUMP run with homogeneous assumption in UP, HL and ADS-4 (Maximizes liquid entrainment and ADS-4 pressure drop)
        - Minimized head in the region accounted for by increased form loss (pressure drop) in the ADS-4 line
  - WCOBRA/TRAC for LTC
    - → Boron precipitation assumes no boron in steam phase

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Roadmap - Break Phase and ADS Phase

Event Phase	Phenomena	Primary Analysis Tool	Validation Method	Alternate Assessment	Conclusion
Break Opens to ADS	Core voiding	NOTRUMP	WCAP 14807 + Comparison to APEX data	None	Acceptable comparison to test data
ADS Depressurization	Core voiding and Downcomer mixing	NOTRUMP	WCAP 14807 + Comparison to APEX data	NOTRUMP simulation of downcomer thermal mixing observed in test	Increased core voiding does not propagate to later phases
ADS Depressurization	Core voiding	NOTRUMP	WCAP 14807 + Comparison to CHF data	CHF assessment relative to data	Core heat flux less than CHF at increased void condition

Validation to CHF correlation using RELAP5 results

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Roadmap - Transition to IRWST Phase

Event Phase	Phenomena	Primary Analysis Tool	Validation Method	Alternate Assessment	Conclusion
Transition to IRWST injection	ADS 4 pressure drop	NOTRUMP	WCAP 14807 + Comparison to APEX data + Detailed analysis of ADS4 piping (FLOAD4)	Comparison to DP data NOTRUM[illegible] Sensitivity Analysis	ADS4 Flow resistance acceptably represented in NOTRUMP Ample margin for ADS4 Resistance uncertainty
Transition to IRWST injection	Level swell	NOTRUMP	WCAP 14807 +Comparison to full scale data	Compariso[illegible]o APEX data	Acceptable comparison to full scale and APEX data
Transition to IRWST injection	E[illegible]inent	NOTRUMP	WCAP 14807 +Comparison to APEX data	NOTRUM[illegible] simulation [illegible]h homogeneo[illegible] flow in UP/HL/A[illegible]	Acceptable core cooling even with bounding analysis

RELAP5 CLL swelled using drift flux model and conservative heat up assumptions

Independent verification using RELAP5 and data

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Roadmap - Long Term Cooling Phase

Event Phase	Phenomena	Primary Analysis Tool	Validation Method	Alternate Assessment	Conclusion
Long Term Cooling	Level swell	WCOBRA /TRAC	WCAP 14776	Additional comparison to full scale level swell data	Acceptable comparison to level swell data.
Long Term Cooling	ADS4 Pressure Drop, level swell, entrainment	WCOBRA /TRAC	WCAP 14776	First principles steady state model	First Principles model confirms equilibrium condition provides adequate core cooling.
Long Term Cooling	Boron concentration	First principles steady state model	WCOBRA/ TRAC for liquid discharge	None	First Principles model confirms equilibrium condition provides adequate liquid discharge.

Bounding assumptions, simplified model

RELAP5 calculations, simplified model and pressure drop data

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Independent Analyses

- CHF Review
  - RELAP5 results were below CHF
  - CHF model is boiling length for appropriate conditions
  - NOTRUMP G, P appropriately predicted
  - Limited review
    - 2200 is the regulatory criterion
      - Can sustain about 100s of adiabatic heatup
    - APEX scaled for blowdown period showed no heatup even for BDBA
- IRWST transition period
  - RELAP5 CLL swelled up with conservative heatup
    - RELAP5 underpredicts CLL during this period
      - AP600 and AP1000
  - ADS4 pressure drop compared to data, simplistic calculation and RELAP5
- LTC
  - Adequate cooling
    - Simplified model and RELAP5
    - ADS4 pressure drop compared to data
  - Maintenance of coolable geometry
    - Bounding calculation to demonstrate no precipitation of boron

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Conclusions

- Review of AP1000 design adequacy
  - Reliance on AP600
  - Focus on differences between designs
- Open items related to 10 CFR 50.46 LOCA criteria
  - Non-LOCA transients and LBLOCA were acceptable
- Independent analyses
- NRC has confirmed the AP1000 thermal-hydraulic design meets the regulatory requirements and can be licensed
  - Definition of evaluation model is preserved