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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

September 21, 2005

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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Wednesday,

September 21, 2005

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ROCKVILLE, MARYLAND

The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, room T2B3, 11545 Rockville Pike, Rockville Maryland, at 8:30 a.m., John D. Sieber, Chairman, presiding.

COMMITTEE MEMBERS:

JOHN D. SIEBER, CHAIRMAN

MARIO V. BONACA, MEMBER

THOMAS S. KRESS, MEMBER

RICHARD S. DENNING, MEMBER

ACRS STAFF PRESENT:

CAYATANO SANTOS

JOHN G. LAMB, Designated Federal Official

TENNESSEE VALLEY AUTHORITY

R.G. JONES

RICH DELONG

JOE MCCARTHY

BOB MOLL

DAVE BURRELL

RICK CUTSINGER

HENRY JONES

KEN BRUNE

TOM MCGRATH

CRAIG BEASLEY

CATHERINE SUTTON

ALSO PRESENT:

GRAHAM LEITCH, Consultant

JOHN J. BARTON, Consultant

PAO-TSIN KUO

SAMSON LEE

RAM SUBBARATNAM

JOE DIAZ

ALSO PRESENT:

ED HASKETT

MARGARET CHERNOFF

EVA BROWN

BILL CROUCH

BOB MOLL

DAVE BURRELL

RICK CUTSINGER

JOE VALENTE

HENRY JONES

ROBERT JONES

STEVEN DART

THOMAS MCGRATH

G. CRANSTON

A-G-E-N-D-A

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

8:30 a.m.

CHAIRMAN SIEBER: The meeting will now come to order. This is a joint meeting of the ACRS subcommittees on Plant License Renewal and Plant Operation.

My name is Jack Sieber, I'm Chairman of today's meeting. With me, on my left, is Dr. Mario Bonaca, who is Chairman of the Plant License Renewal Subcommittee, the section handling the Browns Ferry application.

Other members in attendance, today, are Dr. Richard Denning, and Dr. Thomas Kress. Our ACRS consultants, Graham Leitch, and John Barton, are also present.

John Lam of the ACRS staff is the designated federal official for this meeting. Cayatano Santos, with the ACRS staff, is also in attendance to provide technical support.

The Tennessee Valley Authority voluntarily shut down all three Browns Ferry units in 1985. Units 2 and 3 were restarted in 1991, in 1995, respectively. Tennessee Valley Authority plans to restart unit 1 in May 2007.

Tennessee Valley Authority also submitted

a license renewal application for Browns Ferry units 1, 2 and 3. The purpose of this meeting is to gather information regarding the modifications and startup activities at Browns Ferry unit 1, especially in consideration of their application for license renewal.

This will support ACRS reviews of the license renewal application for Browns Ferry units 1, 2, and 3, as well as restart activities at that plant. We will hear presentations from representatives of the Tennessee Valley Authority, and the Staff.

The subcommittees will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full committee.

I would point out that on October 6th the full committee will meet at its regular monthly meeting, and will consider the salient issues that are developed at today's meeting.

The rules for participation in today's meeting have been announced as part of the meeting notice previously published in the Federal Register. We have received no written comments, or requests for time to make oral statements from members of the public regarding today's meeting.

A transcript of the meeting is being kept and will be made available, as stated in the Federal Register notice. Therefore we request that participants in this meeting use the microphones located throughout the meeting room, when addressing the subcommittee.

The participants should first identify themselves, and speak with sufficient clarity and volume, so that they may be readily heard.

Before we proceed with the meeting I would like to introduce Dr. Mario Bonaca who, as I said before, will be responsible for the plant license renewal subcommittee activities. Dr. Bonaca?

MEMBER BONACA: Thank you. We have scheduled, in fact, a subcommittee meeting to address the unit 1, 2, and 3, Browns Ferry units, license renewal on October 5th.

However, given the complexity of the application, and the differences between the plants, and the plans of the licensee to operate the plant, there are a number of questions that have come under review that would be important to clear today, so we get information regarding those.

And that can set the stage for a more effective meeting on October 5th. At least we have

information that right now we haven't had available. And, hopefully, these questions will be raised.

Many of them are really for the Staff, and the ACRS itself. From my reading I think there are a number of issues that we need to get some information on.

One is, you know, the basic assumption has been made, in the application, that operating experience for units 2 and 3 is applicable to unit 1. In reality, in the SER, that is not as simple as that.

The SER has other considerations in it that may, whatever is missing from the operating experience of 2 and 3, more applicable to unit 1. That includes the restart inspections, that includes evaluation of materials and environment dispositions.

It includes the use of corrective action programs should something be missed. There is a full articulation of elements of how you compensate for the lack of total operating experience for unit 1.

And some of these issues are well discussed. But there isn't, in the SER, anywhere that I could find, and the Staff can talk about that during the day, there is missing a section where this philosophy is being explained.

I think it is important since the SER is

a communication tool for the public, too, that there is a place where this issue is dispositioned. And, again, there is a philosophy, through the SER, and has been done. That is an issue that should be discussed. Hopefully we can hear something about it today.

Second, the application in and of itself blurs, to some degree, restart activities with license renewal activities. And there is an effort, in the SER, to separate them. We should talk about how successful that is, and what else needs to be done to address that.

There are issues of periodic inspections, versus one time inspections, that keep recurring in the SER. First of all there is a statement that says, we move to periodic inspections, then there are statements that talk of one time inspections.

So, also, these issues should be clear. You can see where I'm going. I mean, by the 5th, at least we will have sufficient information to know what is up and what is not up, okay?

And so this day, I think, should be very helpful to lead us to that. By the way, when I talk about operating experience I was referring to the experience that Browns Ferry 1 will have by the time it walks into license renewal in 2013, considering

that also will have the power operate, you know, preceding that action.

So with that, at least we will have on line some of the issues that we need to review. And if there are others that members would like to bring up now?

MR. LEITCH: I guess just one concern that I have, just so that we can begin thinking about this, as we move through our discussions. As I could see how unit 1, how unit 2 and 3 operating experience might be shown to be applicable to unit 1, if unit 1 was still at the original power level.

But the question in my mind is the intent is to bring unit 1 back at the new higher power level? And my question is, basically, and also with renewed license.

So what is the basis for our operating experience, for granting that renewed license, when we havEn't seen unit 1 operate at all, very much. But at least we could say, well, one might be able to justify the unit 2 and 3 being applicable at the original power level.

And how is that unit 2 and 3 at all applicable to this new plant?

MEMBER BONACA: Yes, as I mentioned --

MR. LEITCH: Which is unit 1.

MEMBER BONACA: Same issue. And we dealt with that issue, also for Dresden and Quad Cities, and we asked for a report. So that is an issue that, you are absolutely right, has to be addressed.

Because, as I said before, when you walk into license renewal, in 2013, the plant will be operating at almost 4,000 megawatt thermals, and not at the 1,300.

CHAIRMAN SIEBER: Okay. Are there any other questions, comments?

MR. BARTON: What are the project goals for unit 1 that Tennessee Valley Authority has documented? It is to return a unit to a better condition than when it was originally licensed.

Now, my question is, how can you say that, when some of the equipment, they've spent a lot of money to replace a lot of the equipment. But some of the equipment and structures are going to be some 30-years old when they restart.

So how can you say that it is going to be better than originally licensed? Does that mean when it was originally licensed it wasn't in excellent condition? I would like them to address that.

CHAIRMAN SIEBER: All right, I'm sure that

they will.

Before we begin with the Tennessee Valley Authority's portion of the presentation, I would like to ask Pao-Tsin Kuo for a statement from the staff.

MR. KUO: Thank you, Chairman Sieber, and good morning. My name is P.T. Kuo, the program director for the license renewal and impacts program. I have several other staff members present here today.

To my right is Dr. Samson Lee, who is currently the second chief for the project management in license renewal program. And also next to him is Radioactive material Subbaratnam, and Joe Diaz. Both of them are the project managers for the Browns Ferry license renewal application.

And I also have Dr. Hackett, project director for the operating reactor, and I have project managers Margaret Chernoff, and Eva Brown, so they are both here, so just in case that you have any questions.

And we have staff present here. As Chairman Sieber talked about, Browns Ferry unit 1 was shut down in 1985, voluntarily. But on December 31st, 2003, Browns Ferry Nuclear Power Station submitted their license renewal application for all units, units 1, 2 and 3, for license renewal.

At the time of request the intent was to have both license renewal applications and the EPU, extended power uprate application reviewed in parallel.

During the course of review we found some difficulties in reviewing both applications, so we talked to Tennessee Valley Authority, and as a result of the discussion, by letter of January 7th, 2005, Tennessee Valley Authority agreed to decouple the EPU review from the license renewal review, so that the safety review for the license renewal application can be reviewed independently.

I just want to make that clear, that although there are activities going on at Tennessee Valley Authority for power uprate, but for the license renewal review, we separate EPU from license renewal.

So the license renewal review will be based on the current licensing basis, rather than the 120 percent power level. The license renewal review is based on the current power level.

MEMBER BONACA: I have a question, by the way, with that. Nowhere could I find in the application, or the SER, where the modifications being considered right now are being implemented for power uprate are part of the modifications documented in the

license application and the SER.

MR. KUO: They may have done the modifications for full power uprate, they may have. But for license renewal review our focus is on the current --

MEMBER BONACA: I understand that. But throughout the SERs there are statements, from the Staff, asking the licensee what components have been changed, and what have not been changed.

Now you have this information, we haven't got it yet, because the SER is not clear. That is why I have this question, and I would like at some point somebody tells me what is reflected in the license renewal application and the SER, does it include the modification for power uprate, or not.

MR. KUO: We plan to clarify that in the October 5th meeting.

MEMBER BONACA: Good, that is fine.

MR. SUBBARATNAM: This is Ram Subbaratnam, project manager. In the principal review matters of the SER, on section 1.3, the first bullet and the second bullet, clearly depicts the concept of the philosophy how the view has been done for the SER.

How they decoupled the power uprate from the license renewal. Then we also talk about the

missing components, how the current licensing basis of unit 1 will be made compliant with unit 2 and 3.

See we kind of briefly described the philosophy in that particular part. Tennessee Valley Authority in today's presentation, when they describe the hardware changes, that they have made for unit 1, they will probably try to show you what those hardware changes are, how many of them incorporate the modifications, the need for the proposed power uprate.

I think the details will come out in the wash when they are discussed today.

CHAIRMAN SIEBER: Okay.

MR. BARTON: Mr. Chairman, I have one more I forgot to mention.

CHAIRMAN SIEBER: Okay.

MR. BARTON: I would like the licensee to describe, in his restaRt program, why there is no transient testing planned. I don't understand how you can start, basically a new plant without doing some, run back some trips, and throw significant power levels.

And I assume, from their comments, they don't plan to do that. So I would like them to address that.

CHAIRMAN SIEBER: Okay, I'm sure they will

when the time comes. Any other questions or comments from the ACRS members?

MR. KUO: I just want to say that on August 9th, 2005, we finished our draft, not draft, our Safety Evaluation Report with open items, and we subsequently forwarded it to the members of the ACRS committee.

And there is a meeting scheduled for the subcommittee on October 5th, as the Chairman mentioned before. And my understanding was that the meeting had a visit, at the planned site, on August 23rd of this year. And this meeting is a follow-up meeting for the Tennessee Valley Authority to provide an overview, to the members, all the Tennessee Valley Authority activities, including license renewal.

And that the Staff was not prepared to make any presentation today.

CHAIRMAN SIEBER: Thank you. I notice that our agenda consists entirely of TVA speakers, which is fine. They posses the information that we are soliciting at this point in time, and I'm absolutely sure that coupled with our visit, in August, to the plant site, today's meeting, and next month's meeting, that we will gather, hopefully, sufficient information for us to decide whether an

interim letter is appropriate, or not, and whether issues need to be more thoroughly addressed by the Applicant and the Staff.

So with that I appreciate the fact that the Tennessee Valley Authority people are here, and that the Staff has supported this meeting. And what I would like to do at this time is to introduce Mr. Crouch, of Tennessee Valley Authority, who will start off by giving us regulatory background.

I think while you are getting ready I will mention a couple of things. The ACRS has a statutory responsibility to review certain things, of which license renewal is one, and extended power uprate is another one.

We do not have a statutory responsibility to review the restart activity. On the other hand we have a great interest in that because it is a unique occurrence, so far, in the fleet of plants.

MR. KUO: Mr. Chairman, before they start could I make one other comment?

CHAIRMAN SIEBER: Okay.

MR. KUO: I have Dr. Samson Lee here, and this may be his last ACRS meeting presence. He is moving on to other bigger and better things. But I just want to recognize his contribution to the license

renewal program.

CHAIRMAN SIEBER: Thank you.

MR. CROUCH: My name is Bill Crouch, I'm the site licensing and industry repairs manager at Browns Ferry nuclear plant. I want to thank you for the opportunity we have to come and talk to you, and tell you about the story that we have for Browns Ferry.

Browns Ferry unit 1 is a plant that is in recovery, and we are very proud of what is going on there, and we want to talk to you about that. We have brought a team, our core team of unit 1 recovery, that as, Dr. Sieber said, we have all the knowledge that maintains unit 1, so we want to talk to you about it.

Let me tell you a little bit about the team members that we have here. We have brought Joe Valente, who is our unit 1 engineering manager. And I will talk a little bit more about these people as we come to them, in the time of their presentation.

We have R. G. Jones, who is the restart plant manager. We have Rich Delong, who is the unit 2, 3 and overall site engineering manager. We have Joe McCarthy, who is with me, who is part of my licensing staff. Joe will also be helping me to run the slide presentation today, and make some of the

presentations.

We have also brought along with us other people who are part of the core team of the unit 1 recovery. We have Bob Moll, Dave Burrell, and Rick Cutsinger, who are the mechanical, electrical, and civil aspects of our engineering team.

We have Henry Jones, who is also in the unit 1 engineering staff, who has been a long time person as part of the Browns Ferry engineering effort. Ken Brune is the program manager for license renewal, Tom McGrath, who is the unit 1 operational readiness manager, and we have Craig Beasley, who is our public relations person for Browns Ferry.

We also have Catherine Sutton with us from Morgan Lewis & Boccius. That is our overall team that we have here.

Let me tell you, this team was pulled together specifically for the purpose of doing unit 1 recovery. We have been together, as a team, during unit 2 recovery, and unit 3 recovery, and now unit 1 recovery.

So this is something we have done before, we have a vast amount of experience on what it takes to recover a unit, and we are taking the experience from what we have done, from two previous times, and

we are applying it to this unit 1 recovery.

Overall, if you look on page 1 of your handout, I will briefly talk about what kind of agenda we are going to go through. First of all I will go through and present some information about the regulatory history of Browns Ferry, the regulatory background behind license renewal, and EPU.

Then after we get done with that, Joe Valente, and R. G. Jones, will talk to us about what we are doing to actually recover unit 1. As we put here, how to make unit 1 operate the same as units 2 and 3. There will be strong fidelity between the three units once this is over with.

Then we will move on to the license renewal aspects, talk about what we are doing for unit 1 and unit 2 and 3 license renewal, to extend the life of this plant from 40 years out to 60 years.

Then as Dr. Kuo said, this is an application for license renewal. The application for EPU is a separate application. But, obviously, there is impact from EPU operation, back on license renewal. And while we are not specifically here to present the full details of EPU, we are going to talk about the impact of EPU on license renewal, so that it is addressed upfront.

And then, obviously, as we get along, further on down the licensing road, as we start talking about EPU, in particular, we will come back to this once again.

That is our overall plan for how to get through the day. You had sent us a series of questions. We have woven those questions into the presentation. Some of them are included directly on the slide, you will see the answers.

Others are part of the backup information we will give, as we are talking along. If we get to a topic and you still have questions about something, we will address that, at that time.

So we intend to go through all the questions that were given to us. With the exception of one of them, which is really a question for the NRC, it is a question about what inspections will be done.

And so that will be addressed at the October 5th, 6th meeting, by the NRC staff. Any questions before we get started?

(No response.)

MR. CROUCH: If you will turn to page 2 in your handout, as Dr. Kuo talked about, there are three major issues before Browns Ferry. The license renewal

for Browns Ferry was submitted as unit 1, 2, 3 license renewal, and it was submitted at current license normal power.

The reason it was done at current license normal power was that that is what we are licensed for, right now, and if we address license renewal at EPU type conditions, the NRC staff was concerned that approving license renewal under those conditions would be an implicit approval of EPU.

So we intentionally separated the two apart. So when you read the license renewal application it is written only at current licensed normal power. And as we will talk, that is a different value for unit 1, than for 2 and 3.

But the real basis of the license renewal application is the current license normal power, and the current licensing basis for the plant. Then we submitted --

MR. LEITCH: And what is the design, though, that is discussed in the license renewal application? Is it the specifics of the material, and so forth, is it as the plant is, or was, or will be?

MR. CROUCH: It is discussed as the plant will be when it restarts.

MR. LEITCH: Okay.

MR. CROUCH: We will go through and talk, there has been a tremendous amount of material replacements, piping, tubing, cabling, everything. And what is in the license renewal application is for the new material that will be in there.

MR. LEITCH: Now, that is true for unit 1. Now, is that also true for unit 2 and 3? In other words, further down the road materials are going to be changed on unit 2 and 3 to make it like unit 1, right?

MR. CROUCH: On unit 2 and 3, rather than saying materials will be changed, components will be changed to make it like unit 1. When we do EPU, for instance, on unit 2 and 3, when we go and install new pumps, or new whatever components are required to achieve the EPU conditions, that will be addressed as part of the EPU mod for units 2 and 3, to put those in.

MR. LEITCH: So we are looking at the license renewal application, then, the application is based on unit 1 as it will be in May '07?

MR. CROUCH: That is right. And as units 2 and 3 will be in May '07.

MR. LEITCH: Oh, as they will be in May '07.

MR. CROUCH: That is right.

MR. LEITCH: Which will probably be as they are now, right?

MR. CROUCH: That is correct. The EPU implementation for units 2 and 3 happen just after unit 1 restart.

MEMBER BONACA: Although you do not address the EPU, which I understand, but then the components that you are addressing, in the license renewal, are those that you already have, will replace for the EPU.

I mean, you have a larger, certain larger components that you have installed, okay? So those are reflected in the license renewal application, I mean?

MR. CROUCH: That is right, for unit 1.

MEMBER BONACA: And the reason is that the materials and the environment will be the same whether or not they are larger?

MR. CROUCH: That is right.

MEMBER BONACA: So the only issue that is left is, you know, issues tied to the EPU performance which means, essentially, the environmental conditions are going to be different, but --

MR. CROUCH: That is correct. And when we get, later in the afternoon, when we get to the EPU,

we will talk about the fact that when you go to EPU there is not, really, a tremendous change to the plant that happens, as far as license renewal is concerned.

There is only a handful of systems that experience increased flows, pressures, and in a few cases temperatures. And that is all handled by existing aging management programs.

MEMBER BONACA: Well, you may remember that in the Dresden and Quad Cities we established a requirement that a plant that goes to EPU, after achieving EPU, and before entering the operation, perform an evaluation of the impact of moving to EPU on license renewal commitments, and incorporate, and present that.

So that, as a minimum, would have to be done anyway, because now it is engulfed, it is one of the -- okay.

MR. CROUCH: So as we talked about, there are three major issues that are going to be done sequentially in approval space, so that they are discrete components, as we go along.

We will have our approval for license renewal, we will have an approval for EPU, and we will have approval for unit 1 restart. This is all coordinated through the NRC staff, as we started this,

as Dr. Kuo talked about.

We recognized that we had to do this in a planned fashion. And so as we go through this, as you've already mentioned, the ACRS staff will be needed to give an approval for the license renewal, and EPU applications.

Then the NRC staff will be required to approve the unit 1 restart, and license renewal, and EPU. We have the NRC staff working on that now.

And then, finally, when we get ready to restart unit 1, the process for restart will be governed under a manual chapter, that we will talk about a little bit later, and it will require NRR, and regional approval to restart unit 1.

To give you a little bit of regulatory, or history type background for Browns Ferry, so that everybody is on the same page as to what Browns Ferry looks like.

All three Browns Ferry units are General Electric boiling water reactors, with a Mark 1 containment. The original plan was to construct a two unit plant, units 1 and 2, and then unit 3 was an add-on unit, after the unit 1 and 2 got conceived.

And so they are all integrated together. There is shared components back and forth between the

three units. And we have recognized that as part of our license renewal and EPU applications.

The plants were designed and constructed by Tennessee Valley Authority. Unit 1 and 2 were licensed in 1973 and 1974, respectively. As everyone was probably familiar with Browns Ferry, knows about the fire that occurred in 1975.

At that time both of the operating units were shut down. Unit 3 was still under construction at that time. Unit 1 and 2 were returned to service in 1976, and operated until 1985.

One of the questions that has come up, through various avenues is, is this unit 1 recovery actually recovering from the fire? No, it is not. As it says here, unit 1 was recovered, and it operated after the fire.

So this is not a fire recovery type restart that we are going through now. Unit 3 was licensed in 1976, and then operating until 1985. The final bullet down there gives approximate years of operations.

This is in calendar years, not in effective full power years. And this includes the time before the fire, and then after the fire. So unit 1 was approximately ten years of operation; unit

2 and 3 as shown there is 23 and 18 years, respectively.

Moving on to page 4. As was discussed at the initial meeting, all three Browns Ferry units were shut down in March of 1985 because of regulatory and management issues. We had not come up to the current standards on all the various regulatory issues, and it was perceived that we had management problems.

Shortly after we shut down the NRC issued a show-cause letter for all the Tennessee Valley Authority plants, and requested Tennessee Valley Authority to specify the corrective actions that would be taken to restart.

In response to that Tennessee Valley Authority submitted a three volume nuclear performance plan in August of 1986. And it outlined the steps needed to restart the units.

And this is a three volume document. The first volume specified overall corporate changes that needed to be made. Volume 2 was the Sequoia restart plan, and volume 3 was the Browns Ferry nuclear performance plan. It outlined the things that Browns Ferry had to do to get restarted.

Overall what we need to do is management and organizational changes that had to be made.

Process and program improvements, and it also outlined special programs that were technical issues.

The process and program improvements include such things as improving our design control program. At that point in time we were operating under a two drawing system, and we have now gone to a single drawing system.

We have improved our corrective action program, we put additional controls in our maintenance programs, lots of things like these that were organizational and management type changes, that fed down into the processes and programs, to make sure that we were operating the plant in a controlled manner.

We also had several special programs that were culled out. These were technical programs, such things as seismic programs, appendix R, EQ, etcetera. And we will talk about those in more detail later on.

So the nuclear performance plan gave the overall plan for how to restart Browns Ferry. At that point in time we committed that we would obtain NRC approval prior to restart of any of the units.

CHAIRMAN SIEBER: Just one quick question. The incident that seemed to be a precursor to some of the issues that came up in the 1970s, and early 1980s

was the fire.

And it seems to me, at the age that those plants are, appendix R plants, or otherwise?

MR. CROUCH: Yes. For units 2 and 3 we are in compliance with appendix R.

CHAIRMAN SIEBER: You are in compliance today?

MR. CROUCH: We are in compliance today. There are five exemptions out there, and Joe can talk about those when he gets up here.

CHAIRMAN SIEBER: Okay, I would like to hear what the exemptions are.

MR. CROUCH: He has all that. And then unit 1, up until now, it has been treated as a single fire zone, as part of the units 2 and 3 appendix R plan, it will be brought up to be in compliance with appendix R as part of the restart.

CHAIRMAN SIEBER: But the way it was, when it was shut down, it was not in compliance?

MR. CROUCH: It was not in compliance with appendix R when it was shut down.

CHAIRMAN SIEBER: That is what I thought. And so you will address some of these details a little later on?

MR. CROUCH: Yes. Joe has all the

exemptions, he can talk to them in detail.

CHAIRMAN SIEBER: Okay, thank you.

MR. CROUCH: Page 5, as part of recovery Tennessee Valley Authority implemented the unit 2 restart plan, we obtained a concurrence with the NRC to restart Browns Ferry unit 2 in May of 1991.

At that point in time we recognized that we were going to restart unit 3. And so we took all the lessons learned that we had, as well as recognizing the fact that there was a large amount of regulatory documentation that had to occur.

And we put together that into a proposed regulatory framework document, that outlined how we would go about restarting unit 3. We took all these lessons learned from unit 2, and put them in, and made the regulatory framework for unit 1 and 3.

That framework was approved in April of 1992. At about that same time unit 2 was removed from the Problem Plant List. That was shortly after restart.

Tennessee Valley Authority implemented the unit 3 restart plan, and then we restarted unit 3 in November of 1995, after obtaining NRC concurrence. In 1996 the NRC removed both units 1 and 3 from the watch list.

And if you saw the previous page, it was called the Problem List, and by 1996 the terminology had simply changed, and it was now called the watch list. But it was the same list, basically.

And so unit 1 was removed based upon a commitment that we would implement the same programs, and processes that was employed for the unit 3 restart. And we were not to restart until we obtained NRC concurrence.

So that gave us an overall plan for unit 1, back in 1996. We did not start working on unit 1 at that time, but the plan existed. After unit 3 got restarted we had the first of four consecutive INPO 1 ratings received in 1998.

We had proven our ability to operate the plant safely, and it was recognized by these INPO 1 ratings.

MR. BARTON: That was just one unit at the time, or that was a station rating?

MR. CROUCH: That was a station rating. So moving forward in time to late 2001, early 2002, there was a, due to the need for power, the Tennessee Valley Authority board commissioned a study to be done to look at the feasibility of restarting unit 1.

And after a detailed study of the overall

process of restarting, and providing a supplemental impact statement, it was decided that it was economically feasible, and economically advantageous to restart unit 1.

As part of that study the issues of license renewal and extended power uprate were folded into those decisions. Obviously operating the plant for 20 more years gives you 20 more years for time to recover your investment.

And with extended power uprate you get more power output and hence more return on your investment. So those two programs were integral to the decision to restart Browns Ferry unit 1.

MEMBER BONACA: I have a question regarding the decision in 2002. When I look at the license renewal application, was prepared about the same time.

So at the time, really, you had not yet made decisions on how much piping you would replace, what kind of systems you would modify, etcetera. I mean, you couldn't possibly have done that, because you were scoping.

So as I was trying to review the application I was asking, in my mind, how much has it changed, in the application, between then, when it was

submitted, and for unit 1, again, everything was more an idea than reality.

And today, that is reflected in the SER. I mean, when I look at the SER, it speaks of something that is there, or is being developed. And I'm wondering, if you went back to the application now, and modified that, you would have substantial changes in it, wouldn't you?

I'm not asking you to do that. I'm only saying --

MR. CROUCH: The license renewal application was started, originally, for units 2 and 3 only. And when we got to the point of deciding that we would restart unit 1, we backed up a little bit and included unit 1 in the license renewal application.

MEMBER BONACA: And you did that by adding those commitments in the appendix F?

MR. CROUCH: Adding commitments --

MEMBER BONACA: Which would bring them back into compliance with the licensing basis, and so on and so forth. So I'm just trying to understand, however, about the physical changes.

Because when we came to Browns Ferry in August, you know, you pointed out that you made a lot of physical changes.

MR. CROUCH: Right.

MEMBER BONACA: Piping, in cabling, and so on and so forth. Now, to what extent are those changes going to affect the commitments in license renewal? For example, you may have something that is made of chrome alloy piping, okay?

There is no justification for you to do an inspection of that now because that piping is impervious to certain type of aging degradation. So that is a change I can see there.

And I'm left wondering because the document, as I said, it reflects 2002, and not today.

MR. CROUCH: As I said, the decision to restart unit 1 was made, officially, in 2002. However, the team was obviously pulled together well before that, and starting to work.

And so by the time 2002 came along we already had a very good handle on what we were going to replace from a piping standpoint, cabling standpoint, etcetera, etcetera.

And so then by the end of 2003, when the actual license renewal application went in, we had an extremely good handle on what was going to be replaced.

So it reflects, between the license

renewal application, plus the other information that has been traded back and forth in the request for additional information, it has a very good description of what the plant will look like at the time of restart.

MEMBER BONACA: Yes, okay. Yet, you know, when I look at some of the requests for additional information, I see an evolution of answers on the part of Tennessee Valley Authority, an evolution of answers that seem to be associated with the changes you were implementing.

For example, in some case, you know, you were hitting a hard wall, with the NRC, on some issue. And then you communicated that you were replacing the piping. That killed the issue. That is how it was resolved, the issue.

I guess what I'm wrestling with is the difficulty that one has, as a standard reviewer, not participating in this interaction in understanding, really, where we are today. That is one of the complexities of the application. Okay, thank you.

MR. LEITCH: Just to phrase the question differently and maybe add a little specificity to it. I think there are a number of places where units 2 and 3 have carbon steel piping. And on unit 1 you are

replacing that with chrome alloy piping.

Now, when we look at the license renewal application, is that difference clear, and the aging management programs for unit 1 would be based on the chrome alloy piping, and the programs for 2 and 3 based on the carbon steel piping, is that the way it is set up?

MR. CROUCH: Well, you typically put chrome alloy piping in places like extraction steam, and steam lines, like coming off the HPCI turbine, that kind of stuff. All that is already being replaced in units 2 and 3.

We are catching up to them. They have replaced that over the last two years. And so we will be -- they don't have carbon steel in those locations. If they do, the only part that is left is part of replacements that will occur before the period of extended operation.

MR. LEITCH: Okay, so that is the case where units 2 and 3 are really ahead of unit 1, and unit 1 is catching up?

MR. CROUCH: What we did, when we started unit 1, is we recognized that a lot of the piping in unit 1, specifically extraction steam, had not operated for many years, like we talked about.

MR. LEITCH: Right.

MR. CROUCH: Only ten years of operation. And it was probably acceptable such that we could have gone out and operated unit 1 for 1, 2, 3, or 4 additional cycles without having significant problems in the extraction steam piping.

But we decided to take a proactive approach, go in and take the old carbon steel piping out, and put in chrome alloy piping at this time, so that it would ensure successful operation of the plant for a long period of time.

So we, even though it was not absolutely required replacing this pipe, we went ahead proactively and replaced it, just so we would implement the same lessons learned as what we had seen on 2 and 3.

MEMBER BONACA: That is an important issue. When we came to Browns Ferry it wasn't clear at all, to me, that you had done those changes on units 2 and 3.

MR. CROUCH: Yes, on units 2 and 3 they have been making the same, like for example on the extraction steam pipe, they have been going through, incrementally, and changing out the extraction steam piping and putting in the chrome alloy piping.

MEMBER BONACA: Okay.

CHAIRMAN SIEBER: You supplied us with a list of piping examinations and changes for unit 1. Do you have a similar list for units 2 and 3, and would that be helpful to you, Dr. Bonaca?

MEMBER BONACA: Yes.

CHAIRMAN SIEBER: These sorts of things?

MEMBER BONACA: Yes.

MR. CROUCH: As far as pipe changeouts in 2 and 3, you are talking about pipe changes that have been made in the past?

CHAIRMAN SIEBER: Yes.

MR. CROUCH: We can get that together, we don't have it here today, with us.

CHAIRMAN SIEBER: Well, I'm not sure whether it would be valuable enough for us to have it, to have you put forth the effort to produce it.

MR. CROUCH: Basically we have changed, I don't know how familiar you are with our plant, but we have changed the number 2, 3, 4, and 5 extraction steams out to chrome alloy pipe, both outside the condenser, and inside the condenser.

There is a small amount of piping inside one of the condensers, I have forgotten which one, that when we originally changed it out, we put in

carbon steel, again, and that is in the process of being replaced, again, with chrome alloy.

So very shortly here all of the, number 2, 3, 4, and 5 extraction steam pipings in Browns Ferry 2 and 3 will be replaced with the chrome alloy.

CHAIRMAN SIEBER: Well, I'm not going to ask you for those lists, at this time. I personally don't feel I need them, but if another member, or the Staff would need them, they can let us know.

MEMBER BONACA: That is fine, I don't need them. I would like to --

CHAIRMAN SIEBER: This is very helpful, by the way, for our better understanding of what you are doing.

MR. CROUCH: At each person's place, there, you have three separate handouts, in addition to the book. And let me just tell you what they are, as we go through it. And Joe will talk about these more in detail.

The first one looks like this, it is a multiple page printout that lists all the DCNs that we have done to restart unit 1.

CHAIRMAN SIEBER: Right.

MR. CROUCH: You also --

CHAIRMAN SIEBER: This is something we

asked for in August.

MR. CROUCH: That is something you asked for in August, and you were given a copy of that in August.

CHAIRMAN SIEBER: Right.

MR. CROUCH: You also have another handout that looks like this, that is the piping system replacements. And it goes through and kind of describes where we replaced pipe, and what material we have used.

This particular table is an excerpt from one of the requests for additional information responses that we made. If you need to know which one, I've got the letter here.

Then you have another handout that lists, it looks like this, that contains the NDE examinations that were done on various piping systems.

CHAIRMAN SIEBER: Yes, those documents give us a much better understanding of what it is that you are doing, and what condition the plant is in. Thank you.

MR. CROUCH: If anybody in the audience needs them, they are back on the back tables, the same documents.

MR. LEITCH: A question about that first

handout, the description of the modifications, in the units 2 and 3 related column, most places it says Y, which I guess means yes, but I'm not exactly sure what yes means in that sense.

MR. CROUCH: What this table is saying, let's just start from the left side, and work across, the first column is entitled system and design change. It lists the name of the system, DCN gives a number, that is the design change notice, and a number, it is a sequential number that goes through and lists them.

And, obviously, you've got the description of the change. As you see, there is, we didn't try to put all this in the slides. Many, many, too much change to talk about.

Then the final column, over there, where it says unit 2/unit 3 related DCN yes or no. What this is telling you is, was there a related unit 2 or unit 3 dcn done as part of either unit 2 recovery, or subsequent to units 2 and 3 recovery.

So that what we are showing you is that we are doing the very same things that was done on units 2 and 3 to get to this point.

MR. LEITCH: So why in that column, I just want to be clear on that point, why in that column --

MR. CROUCH: That is what I'm getting to.

MR. LEITCH: Okay.

MR. CROUCH: There are a few DCNs, and I think they are, primarily, all the way to the back, where you see some nos. And the reason there is nos, this is, primarily, the EPU related mods. And they have not been done, yet, on units 2 and 3.

Unit 1 is the lead unit, so we are not copying a units 2 and 3 DCN. We are the lead, and they are actually copying us now.

MR. LEITCH: So Y means that it has already been done on units 2 and 3?

MR. CROUCH: That is correct.

MR. LEITCH: Okay.

MR. CROUCH: It has already been done.

MR. LEITCH: Okay, got you. Thank you, that helps.

MR. CROUCH: Any other questions before I move on?

CHAIRMAN SIEBER: No, you can move on.

MR. CROUCH: I'm on page 7 of the presentation. As we talked about, we had a regulatory framework for unit 1 that was originally created back in the 1996 time frame. As we got closer to unit 1 restart we decided we needed to take the lessons learned that we had from units 2 and 3 operation,

since restart, as well as what was in there for the restart efforts.

And we went through and improved the regulatory framework letter. We also included all the more recent regulatory issues that had come up, if there was new bulletins, generic letters, etcetera, etcetera. Those were all added in there.

So it represented a complete picture of all the regulatory issues that had to be addressed prior to unit 1 recovery. And this was submitted in December of 2002.

As part of that, not only did it lay out things like bulletins, generic letters, it also laid out all the technical specification changes that we would need in order to bring unit 1 into compliance with units 2 and 3.

It was our intention to make, as we will talk about more, our intention was to have one FSAR, one consistent set of tech specs, so that the plants would operate the same, so the operators were operating, essentially, one plant no matter which unit they were on.

The overall process for NRC oversight of the restart effort is outlined in manual chapter 25.09, which is entitled Browns Ferry unit 1 restart

project inspection program.

And it is this restart oversight will be applicable to unit 1 until it is possible that we can transition into the regulatory oversight process for all the cornerstones.

This manual chapter establishes the restart oversight panel, and it is tentatively scheduled to begin this fall, sometime. It will be, from what I understand, it will be chaired by a gentleman out of the region. It will have members on it from the region, from NRR, and several other outside people and stuff like that.

So it will be -- the NRC method of overseeing what we are doing for unit 1 restart. In addition to this restart oversight panel, we have resident inspectors at Browns Ferry unit 1 right now, that are dedicated to unit 1, that are overseeing our efforts.

The final outcome of this manual chapter 25.09, as I talked about earlier, will be the recommendation for restart that will come from a combination of the region and the NRR people.

Moving on over to page 8. As we talked about, the license renewal application was submitted on December 31st of 2003 and it was for all three

units.

As we said, it was originally started for units 2 and 3, we backed up and included unit 1, so it would include all three units. That would ease the process of review for the NRC, and it would ease our process of implementing the programs to make them all the same.

The license renewal application document was prepared and was consistent in format and content with the generic aging lessons learned, the GALL document.

The aging management programs, as we will talk about a little later on, they also have been prepared consistent with the GALL document. There are certain exceptions and enhancements, compared to the GALL.

Primarily these enhancements are places where we actually operate or inspect to a later program than what is called out in the GALL.

CHAIRMAN SIEBER: What version of GALL are you using?

MR. CROUCH: The application was based upon REV-1.

CHAIRMAN SIEBER: Okay.

MR. CROUCH: Ken agrees, it is REV-1.

CHAIRMAN SIEBER: Okay.

MR. CROUCH: The current plan for license renewal approval is in approximately May of next year. Extended power uprate application was submitted on June 28th for unit 1, and June 25th, 2004 for units 2 and 3.

These were not submitted as one combined application because units 2 and 3 had previously been uprated five percent, unit 1 had not been uprated.

CHAIRMAN SIEBER: Right.

MR. CROUCH: When units 2 and 3 were uprated five percent, we increased the pressure 30 PSI, so that that changed the method, the way the plant operates.

So the EPU applications are separate for unit 1 versus units 2 and 3.

CHAIRMAN SIEBER: Now, I take it those are constant pressure uprates?

MR. CROUCH: For units 2 and 3 it will be a constant pressure uprate.

CHAIRMAN SIEBER: At the elevated pressure?

MR. CROUCH: At the elevated pressure.

CHAIRMAN SIEBER: And so the final steam conditions, for the units, will be slightly different

from one unit to another at the final power rating?

MR. CROUCH: No, we will increase the pressure --

CHAIRMAN SIEBER: You will bring that up another 30 PSI?

MR. CROUCH: Yes, we want them to run the same, we want them to be operationally the same.

CHAIRMAN SIEBER: So you won't, strictly, be able to use the topical for the CPU?

MR. CROUCH: No, even the units 2 and 3 EPU was not submitted under the CLTR, which is constant pressure power uprate. We submitted it under the extended ELTR topical.

CHAIRMAN SIEBER: Okay.

MR. CROUCH: The reason being was that as we originally started into it, we were going to use the CLTR, but we were also undergoing a fuel change. And so it was discussed that the CLTR was not applicable to a fuel change plant.

So we submitted it under the ELTR.

CHAIRMAN SIEBER: I think what you are doing is complicated, in that in the final analysis will end up being the wise choice.

MR. CROUCH: The EPU applications for both unit 1 and units 2 and 3, were consistent with GE's

extended power uprate topical reports. This is the ELTR-1 and ELTR-2.

When we initiated our efforts to do extended power uprate, not only did we follow the ELTR in format and content, but we also went out and got all of the requests for additional information from any other plant that had undergone an EPU, as well as looking at their specific application.

And we took all the lessons learned, and folded it into our document. So our EPU applications are bigger in scope and content than what would just strictly be required by the ELTR-1 and 2.

As I talked about, unit 1 is a separate submittal because of the previous five percent uprate. We expect to receive approval for the EPU in approximately May of 2007, which is just prior to unit 1 restart.

MEMBER BONACA: I have a question. Go ahead.

CHAIRMAN SIEBER: These units are what, BWR-4s?

MR. CROUCH: BWR-4s.

CHAIRMAN SIEBER: So that is the slope steam drier?

MR. CROUCH: Yes, we have the slope steam

driers.

CHAIRMAN SIEBER: Okay. Go ahead.

MEMBER BONACA: The question I have is, you know, you are giving your presentation addressing the units 2 and 3, the attempt to make unit 1 identical, licensing wise, as the other units, and so on.

Again, by the time the plant goes into license renewal we will have seen 10 or 11 years of operation, 22 years of lay-up, the power uprate of 20 percent, and about five or six years of operation of the power level.

So it will have an operating history that is substantially different from units 2 and 3.

MR. CROUCH: Right.

MEMBER BONACA: And I think you are recognizing the application, and the interaction for the SER, when you do have, for example, all those evaluations in section 3.1 of the SER, where you are addressing, specifically, potential latent effects of lay-up through inspections now, and those you are committing to inspections later in the licensing period, or somewhere -- I have to understand that.

So you really are recognizing the differences, and you are recognizing the importance of

doing those kinds of testing. Also you are, in some areas, the NRC credits the corrective action program for whatever is going to be missed, it is going to be captured, hopefully, by the corrective action program.

Again, what troubles me at this stage, of the review, is the fact that nowhere in the application, or the SER, there is a coherent description of this aggregate elements to bring, to make the operating experience of units 2 and 3 acceptable for unit 1.

Because that is a sticking issue. I mean, simply, you know, if you look at the Statement of Consideration of the Rule it speaks very strongly of the importance of the 20 years of experience behind the plant, and that specific operating experience.

I think, again, an effort is being made. But, you know, I haven't seen in the application, anywhere, a statement that says it will be applicable because not only we have similarities, of course, in materials and environments, and so on and so forth, but also we are doing the following inspections, we are doing the following etcetera, etcetera, which will plug some of the gaps in the differences.

And I don't know if you have a comment on that.

MR. CROUCH: I think my only comment would be to Rom, that if this needs to be added in to address the issue, then we will work with you to come up with an evaluation so that it can be put into there.

MR. SUBBARATNAM: Yes, this is Ram Subbaratnam, license renewal. Maybe we have to schedule a time to separately discuss that. The unit 1 inspection program was an afterthought, meaning based on the Staff's deliberation.

When we wrote the draft SER it was still like an open item at the time. And, finally, TVA said we have to have some kind of a system monitoring program to have a benchmark and tend to the thing all the way into the acceptance period.

Because this is in development we still have the elements of that new program being worked out. You don't see it in the SER. But in the final SER you will have it, full-blown, added up.

MEMBER BONACA: Because it seems to me that if in the component you do not have an operating history you can trust, you can inspect, and that is what you are doing.

MR. SUBBARATNAM: Fair enough.

MEMBER BONACA: But the point is that, you

know, it is so ad-hoc, something is here, something is there. I think it is important that you have a coherent philosophy that you can express in the SER, if not in the application, that says that is why I can count on units 2 and 3, because we are supplementing that with all these other elements.

MR. SUBBARATNAM: Yes, as a matter of --

MEMBER BONACA: When you are taking credit for corrective action program you have to explain that you are doing it on a limited basis. Because if you have to rely on it extensively it means that you are looking for problems, and then you fix them.

That is not the way you want to relicense the plant. So, okay, as long as that can be done, that would be helpful.

MR. SUBBARATNAM: Yes, I think when we come down October 5th we will, definitely, be well prepared to answer those questions. We will make a distinction between what the restart program is, what the one time inspection is, and what is the unit 1 periodic inspection, which staff worked out, after deliberations with the licensee.

I think that will probably clarify that a little bit.

MEMBER BONACA: Right now the SER is

confusing.

MR. SUBBARATNAM: Because that program is not there, and we are still writing it up, so --

MEMBER BONACA: Well, there is part of it, and then there is -- anyway, we will bring that up later.

MR. SUBBARATNAM: Yes.

MR. CROUCH: So, as I said, unit 1 is being restarted in a controlled manner, as we talked about, where we are trying to make unit 1 operate the very same way as units 2 and 3, we are incorporating all the lessons learned from units 2 and 3, we are incorporating all of the regulatory issues from units 2 and 3.

We have submitted a unit 1, 2, 3 license renewal application, it addresses the concurrent operation of all three units for an additional 20 years.

As part of that overall license renewal application, while it is not being specifically approved as part of a license renewal application, we have addressed the impact of EPU on license renewal.

We know what it does, and we are going to talk about that in a lot more detail during the day today. So that we are confident that when unit 1 is

restarted, at the extended power uprate conditions, and operate for 20 more years, it will operate successfully.

So any further questions on this opening portion of our presentation?

MEMBER BONACA: One last comment I would like to make, from the perspective of Tennessee Valley Authority, I mean, you restart the plant at 20 percent higher power level, and then you know that by 2011 you have to do a number of tests, inspections, to support license renewal.

You know, so you will be monitoring this operation at the higher power level --

MR. CROUCH: That is correct.

MEMBER BONACA: -- and, of course, already we have a commitment that you will have to make regarding submitting a report, and feeding that information into the license renewal program.

MR. CROUCH: And recognize that units 2 and 3 will be going to license renewal just shortly after unit 1 does. So they will be, essentially, operating concurrently at EPU conditions.

MR. LEITCH: Do you have a time frame in mind for when units 2 and 3 are going to have this EPU outage?

MR. CROUCH: The current schedule for EPU is to start up in the 2007 outage, at EPU. So just shortly after unit 1 comes up unit 2 will also come up, and then unit 3 will have its EPU outage in 2008.

MR. LEITCH: And they will be like a year in length, or --

MR. CROUCH: The outage?

MR. LEITCH: The outage, yes.

MR. CROUCH: Oh, no. I don't know what the official length is but it is 35, 36 days. Yes, when we do outages we plan them and we implement them in --

MR. LEITCH: And that is replacing the feed pumps, the condensate pumps, your pump booster, retubing the condenser --

MEMBER BONACA: And the turbine.

MR. CROUCH: Condensers, that is not part of EPU.

MR. LEITCH: And transformer?

MR. CROUCH: The main transformers is already done.

MR. LEITCH: It is already done, okay.

MR. CROUCH: So it is primarily each cycle that --

MR. LEITCH: Turbine unit 2 and 3 rotors,

and HP turbine --

MR. CROUCH: We will be putting in new HP turbines on units 2 and 3.

MR. LEITCH: How about rotors? They have already been changed?

MR. CROUCH: No. The units 2 and 3 turbines will stay their existing design. On unit 1 the --

MR. LEITCH: You are doing the mono-blocks?

MR. CROUCH: We are doing the mono-block LP rotors, and we will do the high pressure rotor, also.

MR. LEITCH: Okay.

MR. CROUCH: During this interim --

CHAIRMAN SIEBER: And that equipment is in place, right?

MR. CROUCH: Beg your pardon?

CHAIRMAN SIEBER: You have those rotors already at the plant, right?

MR. CROUCH: For which unit?

CHAIRMAN SIEBER: For unit 1.

MR. CROUCH: They have not gotten here yet. We had a slight problem with them, they had to get sent back, and reworked. They are scheduled to

come in, in December.

CHAIRMAN SIEBER: But that is not critical to your schedule?

MR. CROUCH: No.

CHAIRMAN SIEBER: Okay.

MR. LEITCH: During this interim, when unit 1 is operating at EPU, and you are still in the EPU outages on units 2 and 3, will there be a different set of operating procedures for each unit?

MR. CROUCH: Yes. Each unit has its own operating procedures, and the operating procedures for a unit will get revised as part of the EPU implementation, to address EPU conditions.

As we will talk later, we are also -- we have two simulators now, and so we will make one simulator correspond to EPU conditions, and one correspond to current conditions, so that the operators will be trained for both conditions.

MR. LEITCH: Okay. Were we going to talk, a little later, about operator training in some more detail?

MR. CROUCH: Yes.

MR. LEITCH: Okay, thank you.

MR. CROUCH: Any further questions about the background on Browns Ferry?

(No response.)

MR. CROUCH: Okay. At this point in time I would like to invite Joe Valente to come up. Joe is our unit 1 engineering manager. As I said, Joe has been part of the team, is part of unit 2 recovery, and unit 3 recovery, and he is now the unit 1 engineering manager.

So he brings a strong historical perspective to what we are doing here. And he is overseeing the efforts. As I said, earlier, supporting Joe we have with us Bob Moll, who is the mechanical engineering manager, as well as the system engineering manager; Dave Burrell, who is the electrical engineering manager, and Rick Cutsinger, who is the civil engineering manager.

And as another point of reference, in case anybody doesn't remember, I was the former mechanical engineering manager for unit 1. And so if other questions come up I can jump in to help Joe, also.

So at that point we will turn it over to Joe. Joe is going to talk to us about the overall philosophy for the unit 1 recovery, about how we've scoped out the project to make sure that all three units operate the same.

He is going to talk about the condition of

the units, what we saw when we started the recovery efforts as far as the conditions after shutdown, and the conditions that we expect to see in the plant, once we do all the recovery efforts.

He is also going to talk about the overall scope of recovery, what it takes in the way of modifications to make the plant operate.

MEMBER BONACA: Let me ask you one question before Joe starts. You said that each unit had its own operating procedures, units 2 and 3 will be different than unit 1, and you are going to talk about licensing later, and training of the operators later.

But are the operators licensed for individual units, or station license?

MR. CROUCH: They have a station license and at that point in time they will be trained for both EPU conditions and current license thermal power.

CHAIRMAN SIEBER: Okay. Joe, before you begin I'm going to give you a great responsibility. You are to speak until 3 p.m. And during that --

MR. BARTON: Do we get a break then?

CHAIRMAN SIEBER: Only some of us. But there is a break, and a lunch period that comes in there. And I think that only you will know best when

to take those.

So if you would keep that in mind as you go through your presentation, and when you find, or think that it is an appropriate place for us to take a break, or to recess for lunch, let me know, and we will do so then.

And I think that will give you a chance to make a smoother presentation, that is less disjointed.

MEMBER BONACA: You want to put a front stop or back stop? He can make us so uncomfortable --

CHAIRMAN SIEBER: Yes, I was thinking about what kind of constraints that I would put on this. And in our ordinary regulatory fashion we have insufficient time to develop the restraints, so we will use common sense, which will be new, right?

Go ahead, Joe.

MR. VALENTE: I'd like to start off by discussing our project objective for restart. When we started the project the main objective was to have operational fidelity between the units.

And we accomplished this by using the same processes and procedures, both in design and in our modification, maintenance, and other activities. So in the design activities we used the same design criteria, we used the same design processes, and we

essentially amplified and expanded the existing, what we call, the baseline essential calculations. We will talk, a little later, on those.

So basically we used the same software that was in existence on the station, and was just a continuation of how the plant was designed.

Same thing in the modification area. We used the same procedures, processes, programs, we used the same loading program, we have the same control on our welding rods, the same work plan, write process, so everything was seamless, for what we did consistent with the operating unit.

Now, our scope of the work for restart included the same restart programs that we used on units 2 and 3. This is commonly referred to as the MPP special programs, and we will talk on those in our next sheet here.

As Bill had mentioned, we also incorporated all the upgrades that were performed on the operating units, from the time of their restarts to the current time. And we looked at the business plan for each unit to identify all the major modifications that would be incorporated from the start of unit 1 recovery, to the end of May of 2007.

Now, this included EPU and license

renewal. So when we did our designs we factored in the license renewal requirements to ensure plant reliability in the extended period.

And we did all our design work, all the analysis work, at a 60 year life, for a 20 year license renewal period, and at 120 percent power. So all those calculations were done for 60 years.

Pipe wall fitting calculations, and so forth, were done for 120 percent power. So that was the basis for our scope here.

Now, when we are done with the recovery effort unit 1 will be operationally the same as units 2 and 3. Unit 1 will have similar systems, equipment, operating procedures, and tech specs, as the other units.

There is only FSAR for the station. Our operators are licensed for all three units, and they will be fully trained on any unit differences. The unit differences are going to be primarily attributed to obsolete equipment replacement.

Now, the majority of our obsolete equipment that we replaced is seamless to the operator. It is more in the maintenance space, different maintenance procedures.

But, basically, the classic work that we

are seeing here on unit 1, we are changing out the control system on the balance of plant side, we are using a foxboro control system.

Units 2 and 3, as a majority, has some foxboro equipment on that control system. Unit 1 will be totally Foxboro. The classic one that we like to talk about, that affects the operator, we've changed out some recorders in the control room to a paperless recorder, on unit 1.

Units 2 and 3 still operate with the paper recorders. So that one is obvious that the AUO has to carry up the paper.

CHAIRMAN SIEBER: Do they still make those?

MR. VALENTE: Yes, they sure do.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: The other unit difference that we see is in the extended power uprate. Unit 1 is scheduled to be the lead plant, as you saw in the DCN list.

Units 2 and 3 does not have the precedent for these DCNs yet, and unit 1 will be the lead. We do have one condition, right now, on unit 1. We have the lead of the LPCI motor generator sets, based on our analysis.

We had the tech spec approved, and unit 1 is doing that. Now, units 2 and 3 is scheduled to remove these in subsequent refueling outages. Unit 2 will take this out in '07.

MR. LEITCH: I don't understand what those motor generators set did. Did they give you variable speed on the --

MR. CROUCH: They are there for electrical isolation.

MR. LEITCH: Electrical isolation, okay. So without those, then --

MR. CROUCH: We went through and redistributed the loads on various boards and there is a scheme for how the various loads load into the boards, in the diesels. So we don't need the isolations provided any more.

MR. LEITCH: Okay, I understand.

MR. VALENTE: That work actually simplifies some of the electrical system.

MR. LEITCH: Yes.

CHAIRMAN SIEBER: That is actually a complicated way to do it. A lot of mechanical equipment.

MR. CROUCH: There was a lot of mechanical equipment that was a maintenance headache, and so

eliminating them was one of the real pluses for the plant.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: Another issue on the LPCI, with regards to the question concerning the LPCI loop selection logic we eliminated this logic on all three units, back in 1977. That was a question that was submitted --

MR. LEITCH: Yes, that was my question, I thank you.

MR. VALENTE: Okay. The other portion here that gets us into a little unit differences, has to do with the outage modification sequencing. And basically what this is, one unit is the lead for a change.

And they are implemented in the outage, and then the subsequent units follow. So there can be a time period, if there is a major modification, that would be implemented, say, on unit 2, then unit 3 and unit 1 would follow that implementation.

So as Bill was explaining, when we implement a modification, our design control process requires all procedures to be brought up to speed before what we call the design package being closed.

So that affects maintenance, operating

procedures, training procedures. So the operator is brought up to speed by the time it gets into the operation aspect of the unit.

Now, the programs implemented to return unit 1 to service have the same rigor, and the thoroughness, as those programs that we use for units 2 and 3 recoveries, there is no difference.

The subsequent performance of units 2 and 3 demonstrated the adequacy of these programs, and we are going to talk about it here in a minute.

So, John, when unit 1 is restarted it is going to be the newest old plant in the country. And we know it is going to be returned to service in a better condition than originally licensed, because we have added a tremendous operating margin in the plant.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: And that is what we are trying to tell you here.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: We have added margin on this recovery, okay?

MR. LEITCH: Would this be an appropriate time to talk about PRA, or do you have that later in the presentation, or --

MR. CROUCH: We can talk about it now.

MR. VALENTE: We can talk to it now.

MR. CROUCH: And we are going to address these questions to Henry Jones, as part of our unit 1 staff over there. Henry, if you want to come up in this direction?

MR. JONES: Yes, sir.

MR. LEITCH: I guess my question, basically, was did you redo the PRA based on these modifications to unit 1? In other words, looking the way unit 1 will be in May of 2007, is there a PRA associated with that?

And is there a significant change in core damage frequency between unit 1 will be, and units 2 and 3 now, for example?

MR. JONES: I'm Henry Jones, Browns Ferry nuclear plant. Yes, sir, we went back and anticipated the configuration of unit 1 at restart, and performed a full level one PRA, and a limited level two.

And on the screen now you will see the results. Of course, for unit 1, this is the first analysis that we have accomplished for unit 1, relative to PRA.

And there you will see both the core damage frequency and the LERF value. And, again, those are values based on a configuration at unit 1

restart.

For unit 2 we have a baseline number which is the number presently in place for unit 2, that assumes unit 2 is operating at 3958 megawatts thermal. And unit 3 is operating simultaneously, also. Those are our baseline numbers.

We have evaluated those models in anticipation of the configuration for unit 2 and unit 3 at restart, at EPU conditions. And accomplished the calculations.

You will notice, for example, on unit 2 there is a slight decrease in the core damage frequency. At Browns Ferry we take our PRA very seriously.

And the time that we made those changes we took the opportunity to also make some additional enhancements to our model. For example we updated the reliability numbers, failure rate numbers of the major components.

We also did enhancements to the model. So that is why you will see a slight decrease. Overall, when you go from the baseline model, like on unit 2 the EPU conditions, we have found the major change is the fact that for those sequences where you have an isolation of the balance of plant, the reactor is high

pressure, for units 2 and 3 today, we really have two makeup systems in that configuration.

One being the HPCI system, RCIC, and also CRD. It is a high pressure displacement pump, but high pressure into the vessel. At EPU conditions we have found, we went back and did our map runs, that we can no longer take credit for CRD.

So that has provided a little bit of a limitation on the number of high pressure makeups at isolated conditions.

CHAIRMAN SIEBER: Flow not enough, is that the reason --

MR. JONES: Flow is not sufficient, that is correct.

CHAIRMAN SIEBER: Okay.

MR. JONES: So that is what really has an impact to make the core damage frequency slightly larger. But, overall, we had a decrease in our core damage frequency.

MR. LEITCH: Were there any EPU modifications made to unit 1, or planned for units 2 and 3, that were primarily driven by PRA considerations?

I'm thinking about did you find that you had to do anything with the standby liquid control

system, like add a third pump, or increase boron concentration, or anything of that nature?

MR. JONES: No, sir. I don't recall any that -- we did increase the SLC system, we did increase the volume that we had to inject. Same flow rate still the same pump configuration, but we did have to increase the volume in the tank.

MEMBER DENNING: Did you do anything with, some plants have automatic initiation of standby liquid control?

MR. JONES: Ours is manual.

MEMBER DENNING: Yours is manual.

MR. JONES: The PRA did not specifically identify anything we had to modify. As Joe alluded to, earlier, in the balance of plant we are going back and putting in larger booster pumps, larger condensate pumps, and actually gaining margin in our balance of plant equipment.

And we found that, obviously, the safety system had adequate flow rates to meet the various safety related requirements.

One note, also, on unit 1 that model was accomplished using the latest ASME standard, as guidance. Whereas the units 2 and 3 models were done a little bit earlier, and they do not include that.

We are putting together a plan to possibly do that in the future. But just that little side note, that there is a little bit different criteria utilized for the unit 1 models.

MEMBER DENNING: What is the difference between unit 2 and unit 3 CDF?

MR. JONES: The Browns Ferry has the benefit of a number of shared systems. And one that is a major additional support, is the RHR system.

Unit 2 is physically located between unit 1 and unit 3. So in addition to the four RHR pumps that unit 1 has dedicated to it, there is also shared pumps.

For example, the unit 1 bravo and delta pumps, and the unit 3 alpha and charlie pumps, can also support all of the RHR functions on unit 2. So, really, unit 2 has the benefit of eight, not four RHR pumps.

And that is what reflects in the numbers, is things like that. The diesel loading is a little bit different, and these things go into making the slightly different numbers.

MEMBER DENNING: Are there any plant damage states that appear as you go to extended power, that aren't important contributors at the baseline?

MR. JONES: I'm not sure I understand your question.

MEMBER DENNING: As you go to higher power there is some new scenarios that suddenly appear, that are significant, that weren't --

MR. JONES: No, we did not find anything that really came up like that. You will find some slightly different system importances as you go across and compare the results.

But nothing unique, or nothing that we didn't expect because of the operation of our shared systems.

MR. CROUCH: Henry, you might want to talk about CRD, how it was -- how you went to EPUs.

MR. JONES: Right, we went through that and the fact that it is no longer capable of --

CHAIRMAN SIEBER: Insufficient flow.

MR. JONES: That was a major thing, because there are a number of initiators that result in an isolated vessel at high pressure.

CHAIRMAN SIEBER: I think what you are asking is, are there success paths that are no longer successful?

MEMBER DENNING: Yes.

MR. JONES: I don't recall any that came

out that way, no.

MEMBER KRESS: As part of the license extension, license renewal, are there plans to do a level 3 PRA for the --

MR. JONES: I'm not aware of any, I can't say. I don't know if the other plants have or not.

MEMBER KRESS: It is generally part of the environmental impact statement that is required, some sort of level 3-like analysis.

MR. CROUCH: We will have to take that as a question and get back to you in the next meeting.

MEMBER KRESS: Okay.

MEMBER DENNING: How about different operating modes, what do you -- this is for the plant at full power operation, or do you have --

MR. JONES: Those are plants are full power operation. We do not have a shutdown PRA. There are aspects, in all of these numbers, that represent the adjacent unit in an outage.

And, obviously, how various outage times, as far as diesel generators, and things, is considered in the analysis. But the analysis is already done at full power operation for all three units.

MEMBER DENNING: And do you have plans for that, do you have plans to do PRA for other modes?

MR. JONES: Not to my knowledge, no. Not at this time.

MEMBER DENNING: You say you take the PRA seriously.

MR. JONES: I understand.

MEMBER DENNING: Yes. And what about fire PRA?

MR. JONES: Yes, we have done, we have accomplished the five method. We have recently accomplished that for unit 1 and found no vulnerabilities, and met the various analysis that have been completed on unit 1, and been finalized.

MEMBER DENNING: Yes, but that is kind of a minimal approach.

MR. JONES: I understand, it is not a fire PRA, it is a bounding screening type of approach.

MEMBER DENNING: Do you have online PRA monitor that you use for units 2 and 3? Do you have it online and you use it to support operations?

MR. CROUCH: Sentinel.

CHAIRMAN SIEBER: Any further questions?

(No response.)

CHAIRMAN SIEBER: Thank you very much, sir.

MR. JONES: You are welcome.

MR. VALENTE: What I would like to do, on this slide, is to discuss the major issues that we had. I want to start off with the nuclear performance plan.

Now, the nuclear performance plan, the special programs that we talked about, these represent the core of the restart effort. It is the same that it did on units 2 and 3.

The programs listed here are very large in scope, and consist of various tasks to confirm data base and compliance with our design criteria.

What I would like to do is essentially walk through three of them. I would like to start off talking about the design baseline verification program, some fire protection in Appendix R, and then talk about intergranular stress corrosion cracking.

Now, the design verification baseline program is a very comprehensive program intended to reestablish the data base for the unit. This was done on the other two units, and this is the extension coming into unit 1.

The scope of these programs are those structures, systems and components, that are required to mitigate the postulated accidents, transients, and special events.

The program consists of three major elements. The first element is to determine the analytical approach and methods, and then establish the procedures to maintain this program.

So we definitized how we were going to analyze for conditions, we controlled it, proceduralized it, so it was consistent, and it was maintained.

The second element here was to establish written design criteria, which established the requirements for each system. And then document these requirements in a safe shutdown analysis.

The safe shutdown analysis defines the modes for each systems that are required to mitigate the accidents, transients and special events. Here is the third element that we will talk about in the lay-up aspect.

The third element is to do the walkdown of the plant. And this walkdown is to establish the as-built configuration. And then evaluate it against the calculation and the analytical basis of the program.

So we have an as-built condition, and we have the analytical condition which definitized all the system requirements and we reconciled that. And this reconciliation is what results in the physical

hardware changes to the plant, that is the DCNs.

A simple process here, but very intent tests. There is a significant amount of output, besides the hardware DCNs. We established baseline calculations, and established the minimum margins.

We established the baseline testing requirement documents that feed into the restart testing program. Those are the major ones here. So when we completed the baseline program, the output from this program allowed us to establish and maintain both our data base and licensing basis.

Any questions on that one? It is a big one.

MR. LEITCH: Joe, I'm not specific on that bullet, but I'm trying to understand this slide. It says summary of unit 1 major issues. And you've got four things there, the nuclear performance plan being the first.

How were those, is that a complete list of the nuclear performance plan, or is that just a sampling?

MR. VALENTE: No, this is, essentially, the special programs contained.

MR. LEITCH: How were those arrived at, were they issues that were problematic at the time of

shutdown?

MR. VALENTE: Yes, that is correct. How we arrived at all of this was in negotiation with the Staff. We had specific areas that there were concerns, both internally and with the Staff.

And we compiled all of these issues into, essentially, 13 special programs. And what you see here are the programs. That is why I say that what you see here, a nice little summary, but it is a very broad issues.

Like when you see electrical issues, it carried on and passed voltage drop short-circuit analysis, coordination, protection issues, all imbedded in there. Same with seismic design.

We went back and we reconstituted the basis for the vessel in the internals with GE. We redid our seismic analysis for all the structures, soil structure interactions were brought up. So they are very broad.

And then imbedded in this seismic design is 79.14, and 2 over 1 issues, so they are very broad, very broad.

MR. LEITCH: Was cable separation an issue? Perhaps that is under electrical?

MR. VALENTE: It is under electrical

issues, yes.

MR. LEITCH: And what about MPSH on your ECCS pumps, do you -- was that an issue, or do you take credit for dry well pressure?

MR. CROUCH: As far as overall NPSH type calculations, that is part of the baseline calculations program.

MR. LEITCH: Okay.

MR. CROUCH: And then as we went on to do the first power uprate for units 2 and 3, and now for EPU conditions, we have redone those calculations. For units 2 and 3 the first power uprate does take credit for containment overpressure.

We had not done that before that time. The EPU application also takes credit for containment overpressure.

MR. LEITCH: Okay.

MR. VALENTE: Basically this slide is tying together the scope from the original one, just definitizing it down, so you see what built the scope for the unit 1 restart, the fidelity going forward.

MEMBER DENNING: Pretty narrow question related to what we are talking about. But with regards to containment overpressure credit, which you have taken, do you evaluate alternatives as to what

you could have done as an alternative to taking that credit?

What would have been required, could you have done something to the pumps? And did you evaluate that?

MR. CROUCH: Henry? I don't remember doing that, but he may know.

MR. JONES: We did look at some alternatives, for example, trying to design pumps that, obviously, would require less NPSH. And our work that we did, we could not identify another type of configuration that would satisfy the needs, as far as pump flow rates.

And, of course, keep in mind that we do require, for EPU, is three pounds, both short term and long term overpressure. These calculations, that Bill talked about, are extremely conservative.

We use maximum flow rates, for short term, for RHR. The design flow rates in the long term we use our design flow rates. So they are conservative calculations. But we did look at alternatives and could not identify any that were available to us, that would replace the need for overpressurization.

MEMBER DENNING: So you couldn't find the pumps that could reasonably be replaced, at reasonable

cost, is that the type of analysis that you did?

MR. JONES: That would require extremely low NPSH requirement for our application.

MEMBER BONACA: What is short term?

MR. JONES: Beg your pardon?

MEMBER BONACA: What is short term?

MR. JONES: Short term is ten minutes or less, wherein ten minutes is long term. That is how we make that distinction in our analysis arena.

MEMBER DENNING: And in this case you needed it for how long, did you say?

MR. JONES: We need three pounds short term, and three pounds long term.

MR. CROUCH: We also, when we do our calculations, we use vendor required NPSH. We know that our pumps will operate at full flow at less than vendor required NPSH. We have demonstrated that through tests back in the '70s.

And so there is margin in there.

CHAIRMAN SIEBER: Well, that is sort of in the eye of the beholder, because the vendor assumes some cavitation when he develops the curves himself. And so there is a range of suction pressures, where cavitation occurs, but the pump is pretty efficient, it doesn't damage itself.

And then as the suction pressure gets lower and lower, you gradually lose some flow, you start to get some chugging, you start to get impeller damage, excessive vibration.

So that is sort of in the eye of the beholder, to know where you are at, at any given time. but I do recall selecting these pumps for new plants, back when the plants were new, and I was new, and there was a lot of effort going into coming up with the optimum impeller design, and for deep draft pumps, to figure out how deep they could be, and still not get a lot of shaft whip, and things like that.

So there may not be too many alternatives that are available today that weren't available at the time of the original design that a licensee could rely on.

MEMBER DENNING: But did I understand you properly, this is just an EPU issue?

MR. CROUCH: Yes. When we went to the first power uprate we took credit for containment overpressure at that time.

CHAIRMAN SIEBER: Right.

MEMBER DENNING: Now, was that when you took your --

CHAIRMAN SIEBER: Five percent.

MEMBER DENNING: Just the five percent?

CHAIRMAN SIEBER: Right.

MEMBER DENNING: Did that imply that when you were at the previous power, that you actually didn't need it?

MR. CROUCH: That is correct.

CHAIRMAN SIEBER: That is right.

MEMBER DENNING: Just the five percent was enough to put you over the margin where it was no longer practical?

MR. CROUCH: Right.

CHAIRMAN SIEBER: One of the interesting things, I think, is that there is a lot of margin in these plants. But the higher you make the basic power level, some of that margin sort of slips away.

And it really doesn't reflect itself in the PRA numbers, except through the success criteria. You know, there is no evaluation in a PRA that says, it will still work, but I don't have the margin I used to have.

And so in a way PRAs mislead us a little bit in that respect. And it could well be that the numbers would be even better under those conditions, where the margin is not used at all.

MR. CROUCH: The other thing to keep in

mind, when I say this happened when we went to first power uprate, we were also, at that same time, resolving the issue of the generic letter 9601 for containment blockage.

And so the new assumptions that went into that also impacted. But at that point in time we put in the new larger stack and went to all the new utility resolution guideline methodology for how to calculate NPSH.

CHAIRMAN SIEBER: That may have forced you into taking credit for containment pressure, even if the power uprate wasn't there.

MR. CROUCH: It might have.

CHAIRMAN SIEBER: You know, I don't know the answer, and you may not know it either. Thank you.

MR. VALENTE: This special program that I would like to talk about is fire protection in Appendix R.

Unit 1 is performing extensive modifications to bring the unit into compliance with the NFPA standards and Appendix R requirements. We are installing a new fire detection and suppression systems on the unit, fire rated compartmentation is also occurring.

We are installing water curtains, we are sealing wall and floor penetrations, and we are installing new fire dampers and doors. We are rerouting cable --

MR. BARTON: Joe, let me ask you, while you are on fire protection, you didn't mention sprinklers. Have you done anything with sprinklers that have been sitting there for 30 something years?

MR. CROUCH: We replaced them all. We replaced all the piping, as well as the sprinkler heads.

MR. BARTON: Okay, thank you.

MR. VALENTE: When I said the suppression system, the piping and sprinklers. Everything from the deluge valves out to the sprinkler heads have been replaced.

CHAIRMAN SIEBER: Let me ask another question, since I have been thinking about this for a long time now. When I walked through your plant I saw you are putting in a lot of new cable trays, that were basically empty.

But I also saw cable trays that weren't empty.

MR. VALENTE: That is correct.

CHAIRMAN SIEBER: Do you plan to abandon

circuits in place when you reroute?

MR. VALENTE: Yes.

CHAIRMAN SIEBER: And, if you do, have you taken into consideration the additional combustible loading in those compartments that you will have, that serve no purpose, other than it is inconvenient to take the cables out?

MR. VALENTE: Yes, we have.

CHAIRMAN SIEBER: And to what extent will that condition exist, unused, abandoned in place cables?

MR. VALENTE: What we had, we had common trays on unit 2 that had unit 1 cable in it.

CHAIRMAN SIEBER: Right.

MR. VALENTE: We de-energized those cables at the time of the recovery.

CHAIRMAN SIEBER: Right.

MR. VALENTE: So our dilemma, on the restart, was go back and perform all the analysis for ampacity, heat load, everything in the existing trays, or run new trays that we could build in the -- not get into having to do anything with flamastic, you know, to check the quality of the cabling.

So our decision was to install the new tray system, and to do the reroutes. So that

eliminated a lot of analytical time that we would have spent.

And that was a lesson learned from unit 3, where we analyzed everything, and then eventually had to make hardware changes, anyway.

CHAIRMAN SIEBER: Well, the concern is the combustible loading, as opposed to whether you got it right in the first place.

MR. VALENTE: That was factored in, on the unit 2. The combustible loading is factored into the fire hazards analysis, it assumes, it took actual profiles of the existing trays. It assumes the new trays will be filled to one hundred percent capacity, and establishing what the fire loading would be for the various fire zones.

So that is considered in the analysis. And the practicality of removing the abandoned cables is problematic since most all of those trays are covered with flamastic, as well, the fire retardant that we put on after the fire in '75.

CHAIRMAN SIEBER: Actually you probably have more than one problem. You probably have some trays that have abandoned cables in them and, also, currently used cables. Separating them would be --

MR. VALENTE: And that was the problem.

CHAIRMAN SIEBER: -- like eating spaghetti.

MR. VALENTE: And that is what we got into in considering whether to analyze any further, particularly in ampacity, if I'm turning on another load in that tray, I'm adding heat load to that tray, and potentially adversely affecting the operating unit.

So the decision was made to reroute.

MR. CROUCH: That is Dave Burrell, our electrical engineering manager.

MR. BURRELL: And that decision corrected a lot of concerns, not only in the electrical issues, but also in Appendix R.

CHAIRMAN SIEBER: I presume that is a matter the Staff will take up when you get ready for restart. But it is an interesting problem that arises when you do this kind of a restart activity and plant modification.

Because I would expect there to be more of it, I think every plant you find abandoned cables. But I would expect you have more than most.

MEMBER BONACA: From this conversation you have abandoned cables, but not abandoned trays. What I mean is that some of the cables in those trays would

still be used?

MR. BURRELL: That is correct.

CHAIRMAN SIEBER: That is the way I would be --

MR. BURRELL: We didn't abandon any tray.

CHAIRMAN SIEBER: Otherwise they would tear them up because that would be the simple thing.

MEMBER BONACA: No, because this is the older, and we have a new cable tray. So the implication was that there is a full replacement. That is what I understood. Now I understand.

CHAIRMAN SIEBER: You know, when we were down there they told us we are replacing everything, but I didn't think that was true then, and I don't think it is true now.

MR. BURRELL: Keep in mind the electric board rooms, we have board rooms on the unit 2 side, board rooms on the unit 1 side, and those board rooms supply the power for both units 1 and 2.

CHAIRMAN SIEBER: Right.

MR. BURRELL: So most of the trays in unit 1 would also contain, potentially contain unit 2 circuits.

CHAIRMAN SIEBER: Right. Well, I think that you can do what you are doing, it is just that it

becomes a tremendously complicated thing. When you consider 30 years of history of playing with cables, and replacing things, and having multiple units in single trays, it just seems very complicated to me.

MR. BURRELL: It is, and we have a very detailed account of every cable.

CHAIRMAN SIEBER: Okay. That plant was built in a time frame where they, sometimes, did not have pull tickets that would fit into somebody's computer, track where every cable initiates and goes, and terminates.

So I don't know whether you have that situation or not. If you were looking at tags on individual cables you can make a lifetime out of that.

MR. BURRELL: The main issue is that we are related back to recovery of units 2 and 3, relative to cable routing, the -- what we found, and we sampled a large population of routing cables, complied with the design, they were pretty much what the design called for them to be.

The issues that we got into were, in some cases, the design didn't adequately recognize some separation requirements.

CHAIRMAN SIEBER: Right.

MR. BURRELL: So from the analysis part we

had to revisit our separations program.

CHAIRMAN SIEBER: Well, I expect you to get an appendix R inspection from the Staff, someplace along the line, and it will be a complex inspection because of your situation. So I would prepare for it in advance.

MR. BURRELL: Our first inspection is in about three weeks.

MR. VALENTE: And we are prepared.

CHAIRMAN SIEBER: Okay, that is good.

MR. VALENTE: The other thing that we are doing, related to cables, is that we are rerouting cables, and we are using some thermal lag on two conduit to get us the separation for appendix R, and the fire rating for --

CHAIRMAN SIEBER: Thermal lag?

MR. VALENTE: -- thermal lag, appendix R.

So we will have cables approximately --

MR. BURRELL: There are some short pieces of thermal lag that we are wrapping some conduit on, that you can't get from point A to B, you can't get out of the fire zone without having some --

CHAIRMAN SIEBER: Thermal lag is now good?

MR. BURRELL: Yes, we have qualified tests, configuration for thermal lag.

CHAIRMAN SIEBER: Be careful there.

MR. BURRELL: We have, absolutely.

CHAIRMAN SIEBER: You may not have the rating that you think you have. And there are a lot of stories about thermal lag, but that, too, is an issue.

MR. BURRELL: I understand. But we performed separate tests with Sandia Labs, relative to thermal lag. We have test reports that support all of our configurations.

CHAIRMAN SIEBER: Well, at least you have Wiley close by there, if you need to test some more, you can just go across the street.

MR. VALENTE: As we alluded to, earlier in Bill's presentation, unit 1 required no new exemptions for restart for appendix R. And we do have fire resistant exemptions, and they will be applicable to one.

And, Dr. Sieber, you asked what they were.

CHAIRMAN SIEBER: Yes, sir.

MR. VALENTE: The first exemption we took was the exemption from no core uncovery. The requirement is that the coolant system, the reactor coolant system posses variables within those predicted for a wash of normal AC power.

Basically there were some time that we could have some core uncovery, analytically, and we had additional analysis to support the fact that the integrity of the clad boundary would remain intact. So that exemption --

CHAIRMAN SIEBER: I don't think you are unique in claiming that exemption.

MR. VALENTE: Right, it is a very short period of core uncovery, and demonstrated no fuel factors.

CHAIRMAN SIEBER: And it is not to a very great depth, either.

MR. CROUCH: That is correct.

MR. VALENTE: The second exemption was from the fixed fire suppression system in the main control room. We don't have the suppression system, we have the detection system, and we have operators there around the clock --

CHAIRMAN SIEBER: You have portable extinguishers.

MR. VALENTE: Portable extinguishers, and fully manned, 24 hours, 7 days.

CHAIRMAN SIEBER: Right, okay. So your operators don't need umbrellas in the control room?

MR. CROUCH: Precisely.

MR. VALENTE: The third exemption is for the RHR pump rooms. Again, this had to do with some separation, the 20 foot separation between the redundant circuits coming down the pump there are some areas where we don't have that separation.

CHAIRMAN SIEBER: And so what is your compensatory measure?

MR. CROUCH: There are fire curtains in the area, there is water spray in the area.

CHAIRMAN SIEBER: Fire curtain is a water system, right?

MR. CROUCH: Right, that is correct. Fire curtain is you basically have a system where it just sprays a curtain of water down so that the fire cannot go through it.

CHAIRMAN SIEBER: And the Staff has approved that?

MR. VALENTE: Yes, an NFPA approved method of separation.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: The fourth exemption has to do with the intervening combustibles. Again, this has to do with the separation, the 20 foot separations. We had some conditions where we didn't meet that.

MR. CROUCH: But in those cases the fire

loading in those areas is very low.

MR. BURRELL: This goes back to your remark, earlier, relative to intervening cable trays between required redundant circuits. And there the combustible loading has been determined to be minimal, and acceptable.

CHAIRMAN SIEBER: Okay. You do have a full fire hazard analysis?

MR. VALENTE: Absolutely, yes, sir.

CHAIRMAN SIEBER: That covers all this, okay.

MR. VALENTE: And the last exemption that we have has to do for the fixed suppression, again, up in the control bay, the control building.

What we have there is there are certain rooms that have non-safety equipment in them, they don't have permanent suppression. Again, the same condition as in the main control room.

There are adjacent areas that have the suppression, the area is manned with personnel, and the exemption was granted on those limitations.

CHAIRMAN SIEBER: Could you give me an example, or two, of your control building, or control tower, or whatever you call it there, where you have non-safety equipment that is not manned and still

doesn't have detection and suppression, and why.

MR. VALENTE: The computer room would be one. It has the detection but not suppression. And this room, it is essentially a concrete --

CHAIRMAN SIEBER: Box, yes.

MR. VALENTE: Stairwell, hallway --

CHAIRMAN SIEBER: Well, the computer room is not immune from fire.

MR. BURRELL: But detection is in.

CHAIRMAN SIEBER: Okay.

MR. BURRELL: And the proximity of personnel with portable equipment is right there.

CHAIRMAN SIEBER: Yes.

MR. VALENTE: Those are the exemptions.

CHAIRMAN SIEBER: And your computer, you have no digital protection systems, right?

MR. VALENTE: No.

CHAIRMAN SIEBER: That are run from that computer, that is just the data acquisition system?

MR. VALENTE: That is just purely data acquisition.

CHAIRMAN SIEBER: Okay, thank you.

MR. VALENTE: Now, where we are at on the fire protection work, is we essentially have completed the fire detection, we are in the process of

performing the testing on the system right now.

On fire suppression we have completed the pipe installation on three of the elevations, we are working on a fourth elevation, and in the corner rooms. And that is scheduled to complete, essentially, in November. So that is proceeding.

CHAIRMAN SIEBER: Do you use halon in any place?

MR. VALENTE: No.

CHAIRMAN SIEBER: CO2?

MR. VALENTE: Yes, CO2.

CHAIRMAN SIEBER: Well, halon you can't get any more, I think. But if you use it, it is hard to test if you can't get replacement chemical. Going back to your fire hazards analysis, I presume the calculations that are done in there are done using the five methodology?

MR. CROUCH: Yes.

CHAIRMAN SIEBER: Yes?

MR. CROUCH: Yes.

CHAIRMAN SIEBER: Okay. Which is a sort of, it will give you a conservative answer?

MR. CROUCH: Right, that is correct.

CHAIRMAN SIEBER: Okay, thank you.

MR. VALENTE: The last program that I will

discuss is the one on the intergranular stress corrosion cracking.

MR. BARTON: Before you skip over -- let me ask you, your fuse program is -- I'm not familiar with what you are doing here.

MR. VALENTE: This program that is listed here had to do with, essentially, the existing fuses that were in the plant. This, again, primarily on unit 2 time frame.

So basically we had to confirm that the existing fuses in the plant were consistent with the analytical basis. That was the issue --

MR. BARTON: So, in other words, the fuses that were in the plant didn't always match the drawings?

MR. VALENTE: That is correct.

MR. BARTON: So you are not changing out all the fuses in unit 1?

MR. VALENTE: On unit 1 we are. Remember the time frame here, this is what existed on unit 2 back in 1985 time frame, when we negotiated the --

MR. BARTON: So you are changing out all the fuses for restart on unit 1?

MR. VALENTE: Right.

MR. BARTON: Now, are you taking advantage

of that time and inspect fuse holders? I don't know what your commitment is, in the LRA, on fuse holders.

MR. VALENTE: Yes, yes, we are. Here is what we are doing. On unit 1 we decided to not perform the analytical exercise, go in and make the physical change based on the baseline calc requirements. So we are bringing everything down, just like -- fuses for sizes and everything, fuse holders are getting changed out, all that is getting changed out, the coordination curves are all checked, it is all standard in the program.

CHAIRMAN SIEBER: Now, you are changing all fuses? All is a big word. Usually when they change fuses they are changing -- the ones that seem to age are the ones that have the springs inside.

MR. BURRELL: We are changing all fuses that are supporting the recovery of unit 1. If it is currently a fuse supporting common equipment that would also involve unit 1, those are not necessarily being replaced.

But all the fuses that support unit 1 recovery are being replaced.

MR. CROUCH: So to say it another way, if it is a common fuse it means it is already supporting units 2 and 3 operation, it is already in the plant

program.

CHAIRMAN SIEBER: So you know it is a good fuse because it is doing its thing?

MR. CROUCH: That is correct.

CHAIRMAN SIEBER: I will caution, when you use the word all --

MR. BARTON: Almost all.

CHAIRMAN SIEBER: Well, every time somebody says all then I get excited.

MR. VALENTE: I understand the guidance.

CHAIRMAN SIEBER: Okay. So if you think it is all, think of exemptions and tell us those.

MR. CROUCH: Joe, why don't we take a break at this time?

MR. VALENTE: That would be fine. How long a break do we want to take?

CHAIRMAN SIEBER: We usually take 15 minutes, and I think we should come back at 20 to 11.

(Whereupon, the above-entitled matter went off the record at 10:25 a.m. and went back on the record at 10:40 a.m.)

CHAIRMAN SIEBER: I think it is time for us to resume. I think, just as a comment, at this point in time I think the TVA folks are doing well to answer our questions, and I think you are well

prepared.

So I anticipate further good performance on your part.

MEMBER BONACA: Is that the expectation?

CHAIRMAN SIEBER: That is an expectation. Okay, go ahead.

MR. VALENTE: Okay. I would like to talk about the intergranular stress corrosion cracking special program here. This program addressed the issue and complied with the guidelines in generic letter 88.01

On unit 1 we replaced all of the IGSCC susceptible piping, including the safety aspect, and we replaced it with 316 NG stainless steel. This total pipe replacement on unit 1 was a difference from the unit 3 precedent, where they only changed out the header and some of the candy cane.

MR. BARTON: This was all the recirc piping?

MR. VALENTE: Recirc, RWC, RHR.

MR. CROUCH: We also, not with 316 NG, but with 333 carbon steel, changed out the core spray piping inside the dry well.

CHAIRMAN SIEBER: So you've, with all this piping replacement, including safety you said?

MR. VALENTE: Yes.

CHAIRMAN SIEBER: So you've had a lot of heat treating going on. And you have records for all of that, right?

MR. VALENTE: Yes. And we have had --

CHAIRMAN SIEBER: And radiographs of all the welds?

MR. VALENTE: Yes, sir. And we have had multiple inspection on our safe heads from the region inspectors, and they are successful.

CHAIRMAN SIEBER: Now, the plant hasn't operated since you replaced the piping, and so you haven't had a hydro, or anything like that. And that will all occur during the restart.

MR. CROUCH: We have not had hydro, but we have refilled the vessel, so the major portions of the recirc loop do have water in them now.

MR. BARTON: So they haven't leaked under head pressure?

MR. CROUCH: Haven't leaked.

MR. CROUCH: Have not leaked.

CHAIRMAN SIEBER: That is a step in the right direction.

MR. VALENTE: One question was, why did we replace all of the piping? And the answer was IGSCC,

and it also facilitated work in our dry well for other ongoing activities.

Now, for stress improvement we are using the mechanical stress improvement process. That is being done. And for the improvement in the operating environment, hydrogen water, chemistry, and noble metal injections are --

MR. BARTON: You are doing noble metal as well.

MR. VALENTE: Noble metals will not be done prior to restart, because you have to have the operating conditions right --

MR. BARTON: But you are going to restart with hydrogen --

MR. VALENTE: That is right.

CHAIRMAN SIEBER: Now, I presume you refilled the vessel to provide some shielding, right?

MR. VALENTE: Yes.

MR. CROUCH: We refilled the vessel to facilitate the in-vessel work going on, the inspection.

CHAIRMAN SIEBER: Okay. Which is, basically, the same. Are you circulating water in the vessel, or is it just sitting there where you can get all kind of hideout, and things like that?

MR. R. G. JONES: This is R. G. Jones, the restart plant manager. We are currently, right now, we do not have direct water cleanup system in service. We have tested it, that was one of the systems that we completely redid.

We have it out of service right now, but we have three 600 gallon per minute tri-nukes in the vessel currently, right now, and we have on 2,600 gallon per minute tri-nuke, that is currently laying there, that is recirculating water to the vessel.

CHAIRMAN SIEBER: Well, you are essentially in a wet lab condition and recirculation is important under those conditions.

MR. VALENTE: Yes.

CHAIRMAN SIEBER: Okay.

MR. LEITCH: Now we are talking about vessel connections, the CRD return line nozzle, to the vessel, has been capped on this unit, is that correct, on all three units?

MR. VALENTE: Yes.

MR. LEITCH: What is the status of --

MR. VALENTE: All three.

MR. LEITCH: All three, thanks.

MR. VALENTE: That was the only items on the performance plan I was going to discuss. And if

there are any other questions --

As I previously mentioned, all of the program scopes and criteria were approved by the Staff during the unit 2 recovery. And I have provided you a copy of the program synopsis.

MR. LEITCH: Now, what is meant by the restart test bullet that is there, could you describe that a little bit?

MR. VALENTE: Yes. This one will describe the process for the restart testing, R.G. and Bob Moll are going to go through this in detail. Do you want to add anything on that one?

It took us through the framework on how you go through and test all your safe laid aspects of the plant.

MR. LEITCH: and we are going to hear more about that?

MR. CROUCH: You are going to hear a lot more about that later on.

MR. LEITCH: Fine, okay.

MR. VALENTE: One of the thing that was questioned, as far as one of your questions, and we will get into this more, a little bit later on, we are talking about IGSCC pipe replacement.

In the question here, along the same line,

what have you also done for your RDVCU pumps and heat exchangers? The pumps have been replaced as new, and Joe will go over that. And three of the five heat exchangers have been replaced, the three reach-in heat exchangers.

All this was part of the overall scope of replacing the IGSCC piping.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: And a little further in the presentation we are going to get down to some systems, we are going to talk about RWCU, is one of the systems. We have some marked up flows and control diagrams, so that you can get a feel for the magnitude of the replacement on the system.

I think the visual will give you a better feel. The other items on this sheet, performance upgrades, again, this is the scope that was put on the units, post their recoveries.

And we incorporated all of that scope up and an example, is the digital feed water, got incorporated. Same thing with license renewal and power uprate.

The original design concept was to bring back unit 1 for a 60 year life, and an extended power uprated conditions. All the analytical work was done

to those parameters, and all the physical hardware changes in the plant reflect that.

So, basically, this is a little bit more detailed from the scope provided on the other page. Page 11. Some other notable programs for recovery include the station black-out, the ATWS rule.

The station blackout was addressed for all three units, during the unit 3 recovery. Now, Browns Ferry has a very reliable and diverse electrical system.

We have seven off-site power lines coming into the station, we have eight diesel generators, four which support units 1 and 2, with four that would support unit 3.

The ATWS rule, that was originally resolved for all three units back in 1989. Currently unit 1 is implementing the DCNs, the design change packages to complete the ATWS requirements. And this includes the alternate rod injection DCN, the recirc pump trip, and the boron concentration in the stand-by liquid control system.

CHAIRMAN SIEBER: Jumping back to the station blackout, what is the condition of the unit 1 station batteries?

MR. BURRELL: The station batteries are

common batteries for all three units, and they are -- so they were replaced, effectively, at the time of unit 2 restart. There have been some material condition issues with shutdown boron batteries, and those are being, or are planned to be replaced later this calendar year.

CHAIRMAN SIEBER: Okay. So they are, what, about 12 or 13 years old?

MR. VALENTE: Actually we replaced them on the unit 3 recovery, not the unit 2. We had a very large outage after unit 2 came up, and there is now 100 plus day outage that we replaced the batteries.

CHAIRMAN SIEBER: But you have a regular plan of surveillances, including discharge tests?

MR. BURRELL: There is a regular surveillance routine for supporting the --

CHAIRMAN SIEBER: And they have continuously been satisfactory?

MR. BURRELL: Yes.

CHAIRMAN SIEBER: Okay, thanks.

MR. VALENTE: VIP, all three Browns Ferry units are committed to the VIP, and unit 1 will perform all their prior inspections prior to restart.

The other items here are the generic upgrades required by the NRC, the generic letters, the

bulletins, and the TMI items. Basically we have 24 outstanding generic letter, 14 bulletins, 11 TMI items, and 21 tech spec changes for recovery.

If you need any specific on those, Mr. McCArthy has it in --

CHAIRMAN SIEBER: What are some of the TMI items that are still outstanding?

MR. MCCARTHY: Joe McCarthy, licensing. Control room design review, the additional review for the human performance. That wasn't done on unit 1, it had been done on units 2 and 3.

CHAIRMAN SIEBER: That is a pretty extensive job.

MR. MCCARTHY: Yes, it is.

CHAIRMAN SIEBER: Okay. Any others that come to mind

MR. BARTON: Might that not, the results of that review might not get into some more design changes in the unit 1 control room?

MR. BURRELL: All the changes, all the human factors, deficiencies, have been identified for all three units, early on, and all of those HEDs are being resolved. How the designs are issued to do the control room upgrades, and the implementation is in process.

Other things related to TMI, certain post-action monitoring instrumentation is being supplemented, or added. And there is other instrumentation changes associated with TMI.

CHAIRMAN SIEBER: One of the tough ones, under REG guide 1.97 was neutron detection to detect re-criticality. I presume -- most people took exemption to that. I presume you did too?

MR. BURRELL: We did the same.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: Everything we discussed on these two sheets, that represented about 2.3 million man hours to do the effort, extensive.

Any questions on this portion?

(No response.)

MR. VALENTE: Next thing I would like to talk about is our lay-up program. The lay-up program, the purpose of our program was essentially an economic asset preservation program.

The systems and components that were determined to be more economical to lay-up rather than to replace in the future were put into the program. We did keep some systems in service to support the operating units, that was a loop of HR service water, and a loop of RHR.

We used the EPRI NP-5106, the source book is the basis for our guidelines in the program. We used both revs. And for dry, we used two types of lay-up, obviously, wet and dry.

For dry lay-up the primary method used was the circulation of dehumidified air through the systems piping and components.

CHAIRMAN SIEBER: That is heated air?

MR. VALENTE: Yes.

CHAIRMAN SIEBER: You are trying to evaporate whatever residual water is in there?

MR. VALENTE: That is correct.

CHAIRMAN SIEBER: That has the disadvantage of, as you are evaporating the water out, the chemical concentration of impurities is going up. So you end up with places in your system where it hides out.

And so you have a very aggressive chemical environment with a little bit of water and air going through there, which some folks think is not good.

MR. VALENTE: All right. We implemented the method by connecting portable dehumidifiers at our piping systems, and then had the exhaust points at the furthest part of the system that we were interested in preserving.

Now, what we used as the standard for our lay-up was that when we made our checks, the relative humidity was to be less than 60 percent on the exhaust air. There was no standing water to be identified on the low point drains, and we performed some limited visual inspections, and we didn't want to see any corrosion, adverse corrosion issues.

CHAIRMAN SIEBER: You plan any additional inspections? I notice, you told us that you weren't taking credit for the lay-up, which implies you are going to do some additional inspections.

Have you identified the places where you feel those inspections are necessary, and what kind you will do?

MR. VALENTE: Well, what we have been doing, we have been replacing so many components and valves on these systems, that we have cut into so many points, that we have made visual inspections at these points.

And what we found was that when we got into them, the original inspections that we did, where we did some UT inspections and so forth, we haven't found -- additional cuts into the systems.

So what I'm going to tell you in a subsequent sheet is how many cuts, how many valves we

replaced out, and how many inspections we were able to make, in addition to what we did from the original material condition walk-downs that we performed.

CHAIRMAN SIEBER: Well, visual inspections are usually the simplest type that you can do. And so if there are areas of concern where visual doesn't really tell you everything, you may have to go to something more volumetric, so to speak.

MEMBER BONACA: The SER, you know, there is a section in the SER which has been added, discussing further lay-up issues, and the plans that you have for additional inspections, and the discussion of separating those which are to establish the proper condition of the components, versus the ones for license renewal, which are --

MR. VALENTE: Yes.

MEMBER BONACA: So there is all the discussion we will have. But in that discussion there is also documentation that you had some problems with the lay-up program. I mean, in 1987 report, for example, from the NRC that establishes that for a certain period of time there were moisture concerns that were not addressed.

And another issue, I believe, with loop boil environment not being monitored, and things of

that kind. So when you discuss the issue of not taking credit for lay-up, let's understand the whole logic behind that.

I mean, you still take credit for lay-up, because you did have components in lay-up, and you are not replacing them. You are supplementing, I believe, that credit with the inspections.

And I think the central issue becomes, then, to what extent those inspections will identify possible latent conditions that may not affect the condition or the method now, but will affect the rate of aging in the future.

And for those, I believe, the strategy is one of having periodic inspections.

MR. VALENTE: Right.

MEMBER BONACA: Which to me implies at least two, to monitor that. So if you could address those a little bit?

MR. VALENTE: Okay. Let me try this. You bring up two very good points. I'm going to start out by talking what we did for restart, and then we will come back into the license renewal.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: For restart, when we say we didn't take credit for the lay-up, is because we did

additional inspections, material condition inspections, to determine that what the analytical basis required was out there, like on the piping system.

Did it have the sufficient wall thickness, did it have sufficient wall thickness to absorb our conditions, our wear rates, and last for a minimum period of years?

And when we get down to some piping I will tell you, we looked at some stuff that had a four year life, and some that had a 13 year life, existing pipe that were in the lay-up program.

But we didn't take credit, when we say we didn't take credit for the program, we didn't care how the inspection was on the lay-up. We did inspections to validate the analytical basis requirements.

MEMBER BONACA: Okay, I understand now what you meant by refurbishing, because we are talking about refurbishing or base lining when we came to Browns Ferry, and that was confusing to me, still, what we meant by that. Okay, I understand.

MR. CROUCH: Basically what it means is we didn't have any place out there where we said, we don't have to do any inspections on this system because it has been in lay-up. That would have been

taking credit for the lay-up. Instead we keep doing those inspections to make sure that we are in good condition.

MR. VALENTE: And just like the report that you were looking at, there, initially when the lay-up program was initiated, it obviously went through a maturing process.

The report that I read, the first NRC inspection, the program is very immature, there were some issues. Subsequent to that the station got more aggressive in monitoring the lay-up program.

The AUOs, review this stuff, essentially, daily. And then reports were generated monthly. The wet lay-up we circulated the water through the vessel, we controlled it to our chemistry instruction, which was more conservative and more rigorous than the requirements.

And that was monitored quarterly. So we did see some excursions on the air, the exhaust air being greater than 60 percent. We did see some excursion where it had some water in the drain points. But those were corrected on.

There weren't any excursions, from what I could see, on the chemistry, on the water through the vessel. That was pretty tightly controlled. Now,

subsequent, the NRC made an inspection, the NRC resident made the inspection on the lay-up program right at the time of the start of DCP, which was late 2001.

And in that report he didn't find any excursions from the requirements. So, obviously, it matured out. Now, in license renewal, absolutely. We are confident that we know that that degradation mechanism is based on what we observed on unit 3.

Unit 3 was sitting idle for almost ten years before we recovered it. Later in the presentation we are going to talk about the RHR service water, we had to replace it, based on a lesson learned from unit 3.

We saw the actual same condition in the delamination in the pipe, on how we laid it up, that we saw on unit 3. So ten years, five, ten years, the delamination occurred, and it occurred on unit 1.

Subsequent to unit 3 coming back, it has ten years of operating experience. And its capacity factors were very high. We haven't seen any condition, based on the operational time period, that we could attribute to the lay-up conditions.

So I understand your question, I have an example of ten years down, down time, with ten years

operating experience, nothing detrimental related to aging, or the lay-up period coming out of there.

Then I have unit 1 with twice the lay-up time, but much more extensive replacements in the piping systems. And I can't give you the definitive answer, but I think the definitive answer is I have ten years of operating experience here, and I think I'm going to see the same thing on unit 1.

Because unit 1 is going to be in a better position because of all those changes.

MR. BARTON: Did unit 3 have a lay-up program in place during that ten years, similar to unit 1's, or not?

MR. VALENTE: Mr. Jones.

MR. JONES: Yes, it did. We established the lay-up program just a few years after that they were shut down, and we put everything in lay-up, and then it stayed in that condition until prior to startup, when we came back with recovery.

MR. BARTON: -- programs that you have in place on unit 1?

MR. JONES: That is correct, sir.

MR. BARTON: Okay.

CHAIRMAN SIEBER: I think one of the interesting things you are going to find, as far as

system integrity is concerned, is that once you get ready to start up and pressurize, you have about, probably, somewhere between 12 and 17,000 valves in that plant.

And I would bet you that every one of them leaks, packing glands. And that --

MR. BARTON: Well, some of them they are repacking.

CHAIRMAN SIEBER: Well, that might be too early, because packing does dry up. But, in any event, there is this block of work that is out there.

MR. BARTON: There are going to be a lot of mechanical leaks.

MR. CROUCH: Every valve is either being replaced, or being refurbished. So it will get new packing. The operators go out there, turn the valves and make sure they work properly. So that will be refurbished before we restart.

CHAIRMAN SIEBER: I have been through that adventure in my lifetime, and it is not a pleasant experience, and it does turn into a lot of man hours. It is not a particular safety concern, other than contamination.

MEMBER BONACA: Going back to your statement of the ten years of experience on unit 3, I

must say that I thought about it myself, but I wasn't helped by the documentation almost anywhere. And nobody made that point, in either the application or the SER.

So, therefore, one is left to his own instrument to say, you know, they did this for unit 3 and lo, and behold, they restarted that. And what was the result of that? You know, if there had been a discussion on operating experience that said, yes, we found this problem, this problem, this problem, we fixed it and, clearly, we have therefore some experience. That is the kind of information that helps.

MR. CROUCH: We can, once again, work to put some of that information in the SER.

MR. SUBBARATNAM: I would like to find out, with respect to the homework you are taking now, when you come back could we have two slides on so many inspections you are talking about, prior to restart, the base line, and you want to talk about inspection.

You need to clearly define, in the context of what you give us, by way of document submittal, what you meant by that, which is applicable for restart, which is applicable to license renewal.

We need to have that clarity clear for the

committee, when you come back on October 5th.

MR. VALENTE: And then, like you said, license renewal had other aspects. You know, what I call the baseline inspection. And we will do that, essentially what we are doing right now, in restart. And then we are going to have the periodic inspections, again, to validate.

We don't anticipate any latent defects coming up in operation. And as Rich will probably tell you, later, in the presentation, we are going to continue those periodic inspections until the data shows that there is no concern.

So it is not going to be a one shot, or a two shot. It is going to go out.

MEMBER BONACA: So that was a question I had in my mind. So when you say that you will have periodic inspection means that if you do, first the inspection at, say, two years before you enter in license renewal, you would perform at least another inspection?

MR. VALENTE: Yes. And my guess is that there would be, at least, a third inspection.

MEMBER BONACA: Because my main concern would be that you fall back on a one time inspection. We have seen it before, the people say we don't have

a problem, and they go the first time, they find no problem, and they say we will never do it again.

MR. VALENTE: That was not our intent. And if I left you with that conclusion --

MEMBER BONACA: No, no.

MR. VALENTE: -- from the August meeting, I didn't present it clear enough.

MEMBER BONACA: No, that wasn't from the other, just from reading the material it wasn't clear to me.

MR. VALENTE: Basically on page 13 you can see some of the systems that we had in dry lay-up, and you can see the systems in the wet lay-up. We did the monitoring results, as I said, the dry systems were essentially monitored monthly in the reports, the wet system was monitored quarterly.

The results that we got from the monitoring program, except for some excursions on the dry, we essentially met the acceptance criteria that we were after.

And, again, no credit was taken for the lay-up program in determining the acceptability of the structure systems, or components, for unit 1 restart. Because we did additional walk-downs to criterias, to support the design basis that we were doing.

Part of the DDPT program was the element, the walk-downs, to reconcile everything up. And once we came through the calculations, after we had that walk-down data, what was acceptable was then looked at by either our system engineers, or maintenance personnel, to determine the actual material condition.

And if the condition came back from visuals that it was extensive problems, we replaced. If it came back that it looks good, then we refurbished.

MR. BARTON: -- assume you included the main condensers, and you put dry warm air through there?

MR. VALENTE: Yes. Is that correct, R.G.?

MR. R. G. JONES: That is correct.

MR. BARTON: Thank you.

MR. CROUCH: Before we go on, some questions have been asked by other people, what was the status of the other systems? Other systems besides these that are listed here as dry and wet, they were basically just drained.

They did not have humidity control on them, or anything like that, but they were drained, and nominally dry. Another question that came up was we've talked some with the license renewal staff about

replacing approximately 3,000 feet of raw cooling water piping.

And the question was, why is this being replaced? Well, this system was also drained. However, some of the isolation valves leaked through and refilled the system, so the system was sitting there with stagnant, untreated water in it.

And so as part of our unit 1 inspections we found this condition, and we are replacing the piping.

MR. BARTON: So the source of that water, what is your raw water, river water?

CHAIRMAN SIEBER: The Tennessee river, right.

MR. LEITCH: One of the systems that would be of concern to me is the turbine, the main turbine EHC piping, hydraulic system. I know that initial startup of these plants, that can be very troublesome, and minute particles can really play fits with the servos, and so forth, and give you all kinds of mis-operation.

And I remember flushing those systems with vibrators on the pipe, and everything, trying to get just minute specs out of there. I wonder if you considered that kind of a problem associated with lay-

up?

MR. CROUCH: RG, a problem?

MR. MOLL: My name is Bob Moll, unit 1 system engineering manager mechanical lead. There are plans, with GE, that has most of the turbine flow work on the TVA service shop to do extensive EHC system fluid flushing, as well as the main turbine system flushing, and in a low boil system, because the piping is bigger, and parts of the HC system, they are also looking at some mechanical cleaning, where that is possible.

Actually that work is scheduled to happen, I believe, later on this fall.

MR. LEITCH: It seems to me that is an area where you are not replacing and, yet, observation, just visual observation may not reveal the particles that I'm talking about, which are quite small.

So I think you almost have to think about flushing in the same sense as with a brand new unit, really.

MR. MOLL: That is correct, that is basically the plans I have in place, is treating it as a brand new unit for both the low boil and the HC.

MR. LEITCH: Yes, I think lou boil is

certainly important but the EAC can really give you fits with very, very small particles.

MR. VALENTE: We will go to page 14, then. Continuing on why we didn't take credit for the lay-up program, the material condition of the structures, the systems, and components, required for unit 1 restart was determined by physical hand-over, hand walk-downs, and inspections.

The results from these activities provided the input into the baseline calculation work. Once that calculation work was completed we were able to determine which valves, components, pump motors, piping systems, that were acceptable, based on the design.

Now, when we met in August you asked me what criteria did we use to come up with this? Each discipline, mechanical, electrical, INC, structural, had specific criteria for the key parameters that they needed for their analysis.

The obvious ones in the electrical, motor size, what it looked like, and so forth. Mechanical was interested in the functional relationship of lines, pipe diameters, wall thicknesses, and so forth.

Civil was after size of members, bolt connections, and so forth. We can tell you more

detail if you want to know the criteria. But there was a defining criteria, each discipline, that this information came back on.

When we determined the component was good, piping system was good, system engineers, or the maintenance personnel went out to do material condition inspections.

We opened valves, we cut into pipe, we put robots in, cameras in, we took UT measurements on 12 systems, we took UT measurements down. Our heat exchanger shells, heat exchangers that were acceptable, the shells were also UTd.

Tube bundles that didn't have a history of any leakage, we did eddy current testing on them, one hundred percent. And the ones that we knew were bad we just replaced out, and new bundles went in.

So if we had a component that was determined, from the analytical basis, to be acceptable, it was looked at either by eddy current, UT measurement, visual.

MR. BARTON: What did you do about buried piping and buried tanks?

MR. VALENTE: We only had one segment of buried piping that affected unit 1, the CRHS service water pipe.

MR. BARTON: You don't have any fire protection stuff that is underground?

MR. VALENTE: There is fire protection, but it is in service.

MR. BARTON: It is in service for unit 1?

MR. VALENTE: Right.

MR. BARTON: What about buried tanks, do you have any of those?

MR. VALENTE: Not that I'm aware of.

MR. CROUCH: Not specific to unit 1. The buried tanks are common to units 2 and 3, and currently in operation, such things as the diesel fuel oil tanks.

MEMBER BONACA: What above-ground tanks, did you do any inspection of bottoms, or internals, on above-ground tanks that were probably drained?

MR. R. G. JONES: They are in service for units 2 and 3.

MR. VALENTE: RG.

MR. BARTON: Condensate storage, they are all common tanks?

MR. R. G. JONES: Yes, sir. They are currently in service and we have divers that will be going into the condensate storage tanks to do an observation and a visual look-through on that before

we start-up.

MR. BARTON: Do you have a good confined space program?

MR. R. G. JONES: Yes, sir.

MR. VALENTE: Yes, sir.

MR. CROUCH: One of the handouts that was given to you was the locations where we had performed NDE, that is the handout that looks like this. This refers to the piping locations that Joe was talking about.

And let me give a little explanation on how we did these piping locations. We did not go in and just randomly select locations. Instead we used what I call smart engineering. We went and looked for places where it would be susceptible to having had water standing, or where you had situations where if it was like a steam system, where it would potentially be susceptible to back, we applied our engineering knowledge, and we would go out and look at the locATions where we would be most likely to find detrimental type conditions.

So we went in. It gives you an idea, on this sheet here, how many places we looked at, how many feet of pipe, that kind of stuff. We looked at the full circumference of the pipe, all the way

around, when we were doing these things.

In all cases the measurements were acceptable in these systems.

MEMBER BONACA: So you looked in specific crevasses and --

MR. VALENTE: What you have there, Dr. Bonaca, is this is a summary and a snapshot in time. Subsequent to this work here, we had done a lot more UT inspection of piping, and we can provide that to you, if you are interested.

But we have done quite a lot of looking.

MR. BARTON: You've got the dry well liner listed on here, four areas, below the concrete interface floor, or were they all above?

MR. VALENTE: No, it was right at that interface.

MR. BARTON: At the interface.

MR. VALENTE: The reason that came in was that --

MR. BARTON: You didn't go down into, through the floor, to the bottom of the dry well?

MR. VALENTE: The interface was right at the --

MR. BARTON: Right at the interface?

MR. VALENTE: Interface, right. As you

know there is a seal that is in there, that we were concerned about trapped water over time. We pulled the seal out, we did the inspection, and no loss.

And the reason we did that, at this time, is we were doing work on dry well coolers and some duct work, and we were going to lose accessibility when the duct work went back in.

So we made, we put the new repair in and we conducted the IWE at that time.

CHAIRMAN SIEBER: Most of the inspections you made were thickness measurements?

MR. VALENTE: Yes.

CHAIRMAN SIEBER: Which presumes a general corrosion, erosion kind of mechanism, as opposed to pitting and cracking. The thickness, UT thickness gauge won't tell you that. So is there any supplemental methods that you -- I noticed a few exams are more definitively volumetric, where you could actually characterize flaws, but not a lot of them.

MR. CROUCH: The UT measurements, they were gridded of in like a four by four grid. They very slowly and meticulously go over the entire area. So even if there is pits they will find pits.

CHAIRMAN SIEBER: Well, you won't find cracks that way. And in four by four is, it may be

okay on some things, but not on others, because if you are really looking for flow assisted corrosion, on small lines, it can be in a very small place, where the turbulence is there, and you can miss it with a four by four grid.

MR. CROUCH: And that is the reason why we used our engineering knowledge of where we were seeing flow corrosion on units 2 and 3, and we went and looked in the same location on unit 1.

CHAIRMAN SIEBER: Yes, that is a good idea.

MR. VALENTE: So we had history on this plant. The configuration between the units is purely consistent. So we did have a focused look --

CHAIRMAN SIEBER: Yes. Well, as much as you say the units are identical they probably aren't. And, occasionally, there are surprises and good engineers aren't surprised very often. I tried not to be.

MR. VALENTE: One of the other things that we did, when we started doing piping replacement, I went to the units 2 and 3 engineer that is responsible for the pipe program and asked him, where have you had to replace pipe?

And then, just like you are saying, there

are some places where you do the small geometry differences, and you have something occurring, but you wouldn't have noticed. Well, I took those and applied them, generically, so we had places where you had some Ts, where you were shooting out the back side of the T, only in certain Ts.

CHAIRMAN SIEBER: Right.

MR. VALENTE: Well, I took that and applied it to all the Ts like that, so that that kind of situation is occurring, I replaced all that piping.

CHAIRMAN SIEBER: Yes, that is a good idea. Good, okay, thank you.

MR. VALENTE: The only other point I would like to make here is on valves and motor that we determined to be acceptable, we had them refurbished to the original OEM spec.

They were sent off to our vendor, they disassembled them, inspected them, made repairs, they replaced the consumables, reassembled, tested them, and sent them back. We monitored the testing.

CHAIRMAN SIEBER: Do you have a pretty big warehouse?

MR. VALENTE: Yes, sir.

CHAIRMAN SIEBER: I imagine.

MR. VALENTE: As I was telling you, on the

next sheet, we are going to get into some numbers. We did cut out a lot of valves, and components, and we performed the additional inspections when we got into those pipes.

They were visual, in the area, and we did do some remote inspections on the core spray RHR, pump suctions, and the main steam lines. We sent a robot down there with a camera.

MR. BARTON: You did three more unit 1 mechanical systems since you put the book together, right?

MR. VALENTE: Sir?

MR. BARTON: Our slide says 39, your slide says 42.

MR. VALENTE: They didn't fix the slide.

CHAIRMAN SIEBER: That is since yesterday.

MR. VALENTE: Well, it will be a long ride home for one of these guys.

(LaUghter.)

MR. VALENTE: On page 15, what I want to do here, each individual system, on unit 1, was evaluated for its adequacy for restart. We got some subsets here, I want to make sure everybody understands.

Each system for restart totally reviewed

individually, and the interactions. Now, what this slide describes is how the unit 1 restart is captures the applicable license renewal systems.

Now, we've got the -- I'm going to take you out of sequence a little bit. 61 systems for restart, we have 47 systems for license renewal, mechanical systems for license renewal, okay?

Restart had physical modification work on 39 of those 47. So, obviously, 8 were in service for the operating unit, we, being unit 1, we didn't have to modify anything, because these systems were evaluated at the time unit 3 restart, for unit 3 operation.

A historical point, unit 3 time, when we were recovering, the intent was to finish 3 and then roll into 1. So all that analytical work was done upfront, and we were touching it, and then subsequent decisions made.

Obviously all of these systems will have some maintenance work on them. And what I'm talking about here is physical changes to the system. We replaced one system, one complete replacement, that is the recirculation system.

We replaced all the piping, the instrumentation, and the electrical cables.

MR. BARTON: Do you have valves, isolation valves in your recirculation piping or not?

MR. VALENTE: Yes.

MR. BARTON: You do?

MR. VALENTE: Yes.

MR. BARTON: What did you do with those valves?

MR. CROUCH: They were refurbished.

MR. BARTON: Refurbished. You reused the packing when you put them back together, disassembled?

MR. CROUCH: Yes.

MR. BARTON: Everything, same thing?

MR. CROUCH: Disassembled, inspected, either repaired or determined to be acceptable, refurbished.

MR. BARTON: Okay.

MR. CROUCH: Consumables replaced, reassembled, tested, testing witness by our source surveillance. That was our standard, safety related, and a lot of non-safety related.

MR. VALENTE: Like we said, we refurbished the existing valves and motors to original OEM specs. Now we get down to some interesting numbers here.

Thirty three of the license renewal systems were partially replaced by design changes or

maintenance activities to meet the requirements. Design criteria requirements for unit fidelity. And the list of DCNs that you had, what is in there.

In these 33 systems, 35 percent of the large bore piping was replaced. This represents approximately 15,300 feet of replaced pipe, compared to a total of approximately 43,000 feet.

For the small bore we replaced 25 percent of this piping. And that replacement equated to, essentially, 19,000, approximately 19,400 feet, compared to approximately 77,000 feet in the unit.

Fifteen percent of the valves were replaced. That is approximately 5,300 valves out of a total population of 38,000. Now, we did a lot of cutting. We cut, we performed visual inspections. Our field engineers did, our system engineers did.

If we had access, we looked.

MR. BARTON: When these valves were replaced, were they replaced with same type valve that was there before, or did you upgrade? In other words, did you change some gate valves because of engineering consideration, or operational considerations?

MR. CROUCH: There were a few places we did that but, for the most part, it was like to like, as far as valve type. Now, you can't always get the

same --

MR. BARTON: Same vendor or whatever, right. But it was --

MR. CROUCH: We also, as part of doing this, we did a lot of stellate removal. We replaced a lot of valves. There was nothing really wrong with the valve, but it contained stellate, we would replace it for that reason.

CHAIRMAN SIEBER: How much cobalt do you think you have remaining, roughly? Some things you can't replace.

MR. VALENTE: I don't know, I have no idea.

CHAIRMAN SIEBER: Okay. I was just curious. It is not something you should know.

MR. VALENTE: Okay, in the electrical arena we replaced approximately 30 percent of the cable on the unit. This represents approximately 800,000 feet of cable replacement, against an estimated total of 2.8 million feet.

Now, the 30 percent cable replacement, on unit 1, represents 80 percent of the safety related cable, okay? For the remaining safety related cable that wasn't changed out, visual inspections were performed at the available access points.

And this inspection was to look for jacket degradation, problems, or anything.

MR. BARTON: Do you have buried cable?

MR. VALENTE: Yes.

MR. BARTON: Was all that replaced?

MR. CROUCH: Dave? I believe all of the buried cable was --

MR. BURRELL: The only buried cable is cable that is supporting common equipment that is currently in service. As a part of having to do some modifications on a couple of those circuits, for appendix R reasons, we did go in and do ten delta tests on them to confirm the integrity of the cables, and they tested good.

CHAIRMAN SIEBER: You may not be able to answer this question. But a lot of times folks consider replacing cable because of the EQ envelope. And so there is always a question as to whether you can reinterpret, or engineer the envelope to show that your conditions aren't as harsh as the testing would have allowed.

Or you can just turn around and replace the cable. Or the third thing is you can ignore it altogether and wait until you get to the end of the period, and then you say, what do I do now?

And do you have any cable in that last category?

MR. VALENTE: Not on unit 1. We replaced the majority of our EQ cable. There were certain cables, supporting unit 1, that were in service. We performed the inspections, confirmed that they were adequate for our conditions.

MR. BURRELL: And that their life would be sufficient to the extended operating period.

CHAIRMAN SIEBER: Okay. There are, from a fire protection standpoint, there is thermoplastic and thermosetting cable?

MR. BURRELL: Correct.

CHAIRMAN SIEBER: What do you have remaining, a little bit of both, or --

MR. BURRELL: There is some of both, thermoplastic and thermoset.

CHAIRMAN SIEBER: Okay. That would have been a criteria that you could have used, is to upgrade for --

MR. BURRELL: But like Joe mentioned, most all of the safety related cable is getting replaced. There would be some places, in appendix R area, that they aren't all getting replaced, and some of that would still be some thermoset.

CHAIRMAN SIEBER: Okay, thanks.

MR. VALENTE: Now, the inspection that we did on the safety related cable that we did replace, we found no indications of degradation. And you have to remember, these cables were de-energized since 1985. So what we saw, at the access points, is representative for what the cables are.

The result of this work that we described, the replacement work, unit 1 is going to be in a better position to operate for the extended period of time. We just handled so much, and changed out so much to new.

As I mentioned, we had eight sections that were in service for units 2 and 3, we didn't have to perform any modification work on it, diesel generators, fuel oil, and so forth.

The package that we handed out on the restart mods, Bill alluded to this earlier, I guess, when Graham asked him. You can look at the first 44 pages and what you will see in there is a yes out there, which means these DCNs, these designs, were already incorporated on units 2 and 3.

If you look towards the back you will find a couple of pages where the answer is no, and those are essentially the EPU DCNs. Those DCNs will be

incorporated on the other units, in their EPU window.

The only true unique DCN that we have on unit 1, associated with the turbine.

MR. CROUCH: Right now there is no plans to go to the monoblock rotors. So the changeover to the monoblock rotors is the only truly unique DCN that we have.

CHAIRMAN SIEBER: But from an operator standpoint that makes no difference.

MR. CROUCH: No difference.

CHAIRMAN SIEBER: I presume, when you talk about fidelity, that is really what you are talking about, because the units can't possibly be identical.

MR. CROUCH: Right, the units, like we were talking about earlier, you cannot still buy Hancock model 78 so and so valve. It would be another manufacturer --

CHAIRMAN SIEBER: Ashcroft, or something.

MR. CROUCH: It would be a gate valve, it would still be a half inch valve, it would still function the same way, as far as the operator is concerned.

MR. BARTON: The operator still turns it the same way.

MR. CROUCH: That is correct.

MR. BARTON: Hopefully.

MR. CROUCH: We want everything seamless for the operator. Maintenance has different issues, procedures are written up, consistent with the design packages when they close out, and everything is tracked that way.

And like Joe was talking about, there are some small ones that are caused by such things as equipment where once again you cannot buy the same piece of equipment any more, but those are really quite small.

MR. VALENTE: I have examples of three systems here that we want to show you. We are going to talk about HPCI. The reason for this system that had the minimal amount work done to it, safety related minimal amount of work.

RWCU, extensive amount of work. And then the feedwater balance of plant system, affected by EPU. So --

CHAIRMAN SIEBER: On the reactor water cleanup system, the connection point to the reactor vessel is a pipe nozzle, right in the bottom of the vessel.

MR. VALENTE: Yes.

CHAIRMAN SIEBER: And that is probably the

point where you have the highest amount of oxygen, if there is oxygen in your system, the highest temperature, and the most aggressive conditions. Have you taken any steps on any of the three units to examine the area around that connection to the vessel?

Recognizing that it is very hard to get to. You have, you know, control rod drive mechanisms, and instrumentation, and all kinds of stuff up in there. Have you done anything like that.

MR. MOLL: This is Bob Moll. On unit 1 the access, the bottom head drain connection on the vessel, we did take ultrasonic UT readings, and -- pardon?

CHAIRMAN SIEBER: Through the inside?

MR. MOLL: No, from the outside. This is externally from the outside, and saw no degradation.

CHAIRMAN SIEBER: That is an industry concern, and I was just wondering how you folks approached it.

MR. VALENTE: We had some robotics.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: Bob, if you would like to get those drawings out? It would be better to talk through this, and you can see we've got the three systems.

We will start with the HPCI.

MR. CROUCH: And what we have here is we have some flow diagrams that have been marked up to demonstrate what some of the scope of the recovery is. We want to use these drawings here, during the course of the discussion today, and we will have these to look at during the day, but these will not be part of the docketed material.

CHAIRMAN SIEBER: You want these back?

MR. CROUCH: Yes, please.

CHAIRMAN SIEBER: Okay.

MEMBER BONACA: For the HPCI system, this is one of the systems that will be periodical inspections?

MR. CROUCH: Yes. Completely disassembled and refurbished.

MEMBER BONACA: We would like to -- the SER, there is a statement there regarding the system, that it will have a one time inspection performed before restart. Is this the statement that is obsolete by now?

Once you are committed to periodic inspection you may do a startup inspection, but not necessarily the license renewal inspection, you don't do that any more. That is more a question for the

Staff because the SER is very confusing on that.

If you go to this system, the SER --

MR. SUBBARATNAM: Yes, I believe we haven't still worked out the details with the licensee on that one. But what they are going to attempt is if the periodic inspection is going to push the thing below the threshold, they said that they would take it under the current for 54B, and then they will take the corrective action program and replace it completely.

That is what they had, at least, agreeing to do that for us.

MEMBER BONACA: My suggestion, if you look back at the SER, it is confusing right now, because after the inspection, then there is a statement specific to this, and other systems like these, that says that licensee has agreed to advance a one time inspection prior to start-up.

MR. SUBBARATNAM: Dr. Bonaca, we are going to revisit those areas, and then we will clean up after we have the unit 1 inspection later on.

MEMBER BONACA: Right. Because, I mean, clearly --

MR. SUBBARATNAM: Yes, that will be --

MEMBER BONACA: -- understand --

MR. BARTON: Okay, I'm sorry, what is your

code here, orange versus yellow?

MR. VALENTE: What we are going to do, John, is Bob and Dave are going to walk through this.

MR. BARTON: Okay.

MR. VALENTE: The one thing I want to tell you, if you look on sheet 16, for HPCI, you will see the synopsis of the modifications down there, various cable relays, pressure switches, changeouts for EQ separation, and other design criteria breakages, 8910 requirements, and refurbish the skip.

If you look on pages 25 and 26 of this big handout you will see the corresponding DCN. We will have Bob walk you through the mechanical portion, and the Dave will walk through the electrical and the INC portion, to give you a feel for what happened.

MR. CROUCH: On page 16 there is a kind of a synopsis of what is being done. And when you look on the big drawings, you've got, that is where Bob and Dave are going to walk through.

MR. MOLL: Bob Moll. Let me walk you through what you have in your package. The very front sheet you've got is a, that would be a high pressure coolant injection. We call that a mechanical flow diagram.

And, basically, it will show you all the

big valves, and the piping, it doesn't necessarily contain all the instrumentation functions. But on that cover sheet what we've done is if it is highlighted in yellow, that is a mechanical valve, or a pipe, that has either been replaced, or cut out.

So all the yellow for high pressure coolant injection indicates valves that have been replaced. So if you look at the upper left-hand corner, you will see FCV732, and 733, those are the primary containment isolation valves for HPCI.

We have cut out and totally replaced those two large motor operated valves, and operators, on unit 1 as part of unit 1 restart.

The orange items, on this flow diagram, are instrumentations that have been, basically the instrumentation has been changed out. You go to the second page, that is a flow diagram of the HPCI oil system.

And what you see are, within the old system we changed out some instruments. There are some thermal welds we changed out. There are also some of those other yellow items that are colored, that is a throttle valve, and we have upgraded the unit 1 HPCI, similar to what we did on units 2 and 3, those throttle valves were replaced with orifices.

The next page is what we call a mechanical control system. And this shows all of the instrumentation associated with HPCI. And, again if it is colored orange that means that instrument is new on unit 1 HPCI, and has been changed out.

So you can see the type of modifications that have been made in the INC area, there, as well as in the electrical area. We have replaced cables, breakers, fuses, thermal overloads, that is not included in what you have in your handout.

But most of the HPCI INC mods were in the INC area were made primarily for environmental qualification reasons, or for fidelity issues that had been, had cropped up as issues on the operating unit, that we picked up in the modifications that we made for unit 1.

And it goes anywhere from condensate header levels, which is to replacing the steam leak detection system for HPCI, replacing temperature switches, converting differential indicating switches, to differential pressure transmitters, the gamut of instrumentation that would be involved.

MR. BARTON: While you were looking at HPCI, you looked at it to make changes based on what units 2 and 3 had upgraded, or whatever?

MR. MOLL: That was the starting point for it.

MR. BARTON: Is that a criteria? How about industry experience with HPCI --

MR. MOLL: All the industry experiences would have been previously evaluated as an ongoing activity for the operating unit, and those mods would have been picked up for the operating units and then factored into unit 1.

MR. BARTON: That would have picked them up?

MR. MOLL: That is correct.

MR. BARTON: Okay.

MR. MOLL: Just to give you a feel for numbers, the yellow lines on the HPCI cover sheet don't look that big. But those yellow lines, on the small bore piping, that actually equates to 1,210 feet of small bore piping on HPCI that we are changing out.

If you looked at the total number of valves, we are replacing on HPCI, was 668, is what the total count was, that we reached out and touched. Some of those valves are getting changed out, other ones are -- most of the packing leak-offs on all the big valves, they are getting cut out, and those lines capped.

So that would be counted in that number, too, when it is getting cut out and removed.

MR. BARTON: The other valves that aren't getting replaced in the system, since they have been sitting around so long, are they being repacked with fresh packing?

MR. MOLL: If you look at all of the, I would call them large bore valves, on here, are all getting worked on. Another effort that has been ongoing since '03, that operations has recently completed, they have gone out and physically cycled all small manual valves.

And basically identified as part of that process, written work requests for maintenance, if those valves are hard to operate, or look like they need work, then there is a work order written.

MR. BARTON: Yes, but that doesn't really, it could tell you the condition of the vacuum, but not necessarily tell you the condition of the vacuum. As soon as you load the system with water, that is going to be part of your test program, I guess.

Because the packing on those valves has been there for 30 years, and hasn't been wetted in how many years? Since '85?

MR. VALENTE: The RWCU, the reactor water

clean up, this one had extensive work.

CHAIRMAN SIEBER: I see you saved the reactor vessel.

MR. MOLL: If you look at the reactor water clean up, the first flow diagram you have, that is all of the reactor water cleanup system piping, with the exception of the demineralizers. There is two of them that are in it.

So you can see, on this first sheet, that is -- we have just about replaced all of that part of the cleanup system, piping and --

MR. BARTON: What about the heat exchangers?

MR. MOLL: Three of the heat exchangers were changed out, the other two were not. If you flip to the next page that shows you the demineralizer portion of reactor water cleanup.

There was very little modification work in this area. Again, cleanup was in service, on unit 1, up until somewhere in 2001, 2002, when the vessel was drained on unit 1.

What we have done with the reactor water cleanup system, outside of modification, we have done extensive maintenance work, and this week just recently finished up.

We have essentially gone through, and cycled, and timed, and checked all of the valves that you see on this drawing, that are air operated, or electrically operated, that are needed to back wash our reactor water clean up demin.

We changed out all of the time delay relays in the logic circuitry, and all of those controls, and set all those back up. And this week we are successful, after all of that work, and we call it a dummy backwash and precoat.

But basically we energize the system, it thinks it has gone through a backwash and precoat. We hit the button and verified it cycled through, and timed correctly. So there was a lot of maintenance work, but no real piping changeout. The only valves we really changed out were some relief valves.

And the next page is the instrumentation diagram for reactor water cleanup. Again, it shows you the instrumentation changes we made.

MR. CROUCH: Once again, that is similar to what we did on HPCI, replaced the leak detection, pipe break leak detection system, replaced various instruments from suction header pressure indication to bearing and casing temperature indication, vibration monitoring was upgraded.

Bump cooling water temperature switch is replaced, flow switch is replaced, about 15,000 feet of cable was replaced, with RWCU, breakers, fuses.

CHAIRMAN SIEBER: Have you done anything on hangers and supports?

MR. VALENTE: Yes, sir. We have implemented 7914.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: And what we call our long term integrity program with hangers. HPCI systems falls in it, RWC falls in it, there is a break for class 1 and class 2 systems. But, yes. All of these systems have had significant hanger upgrades.

In fact, on this recovery unit we have either replaced or modified 85 percent of the hangers.

CHAIRMAN SIEBER: Is there -- that is in the normal course of business, you would have had to make those changes, under the bulletin?

MR. VALENTE: Yes.

CHAIRMAN SIEBER: Whether you were doing a restart or not?

MR. VALENTE: That is correct.

CHAIRMAN SIEBER: Is that because of methods that were used in original construction, or a change in the seismic analysis, or what?

MR. VALENTE: It was a change in our seismic, back on unit 2. We had to go to Housener. Go ahead, Rick.

MR. CUTSINGER: This is Rick Cutsinger, I'm the civil engineering manager in unit 1. On unit 2 we redesigned, redefined our seismic design criteria for this station.

That redefinition brought in new methods, new practices, and a new response spectra. The new response spectra dramatically changed the input to the station, and it caused dramatic mods to all the hangers.

The biggest criteria change probably was from the perspective of stiffness. The original hangers were designed from can the hanger take the seismic load, versus we now have hangers that are designed to make sure that they don't deflect more than an eighth of an inch.

So you see significantly stronger, stiffer hangers. And that is probably the biggest change. But the input motion changed, and the reaction has changed. And so it caused dramatic changes to the hangers, which then went to the structure, and it caused different loads to the platform steel, which we had to make mods to, and just follow on down to the

building.

MR. BARTON: What about subbers?

MR. CUTSINGER: The subbers are all being replaced on unit 1. We have 250 subbers, and they are all being refurbished and replaced.

MR. BARTON: Did you go through a subber reduction program in dry well?

MR. CUTSINGER: No. Since we had about 250 snubbers, total, on the unit, we didn't go to the sub reduction program.

MR. BARTON: You didn't?

MR. CUTSINGER: No.

CHAIRMAN SIEBER: Okay, thank you.

MR. MOLL: The last system we have is a feedwater system. Just looking at almost all of the changes you see on this page, from a mechanical staNdpoint, are driven by either EPU, or I call them lessons learned, operational experience we have gained from units 2 and 3.

Some of that work is work they have done already. A good example I will give you is we are changing out all of the feed pump and inflow valves on unit 1, and the piping downstream of those valves.

That is really based upon a lessons learned. We are on our second version of min-flow

changeouts on either unit 2 or unit 3, trying to stop those valves from leaking by. And our design on unit 1 will be different. But it is a much better valve.

It is a little bit more expensive, but shouldn't leak by. The other big ticket item that we have completed on unit 1 is the main feedwater header check valves, where notorious problems on units 2 and 3 as far as appendix J testing.

We, essentially, get into a major outage refurb probably once every three cycles, thereabouts. We have changed out all four of those check valves with brand new ASME code class appendix J, on unit 1.

The other big aspect of this is we are changing out all three feed pump turbines for power uprate, and are changing out all three reactor feed pumps for power uprate.

Each feed pump will be a 50 percent, I'm sorry I take that back, each -- two feed pumps will handle one hundred percent EPU power, even though we continue to run, we will run three, but each one would be 50 percent capacity, compared to now we have about a 33 percent, or thereabouts, for each feed pump.

MR. BARTON: Are they all steam driven, or do you have any electric?

MR. MOLL: No, all three feed pumps are

steam driven.

MR. BARTON: The feed water heaters aren't highlighted. Did you do anything with the tubes, or anything in the feedwater heaters?

MR. MOLL: Yes. We haven't done anything on the feed water side. On this drawing there is work that we have done on the -- we have eddy currented all the feed water heaters.

We have done some, there are some other modifications we have done, internally, to the heaters.

MR. BARTON: You haven't retubed them, though?

MR. MOLL: No, no retubing.

MR. VALENTE: Eddy current, no problems.

MR. BARTON: pardon?

MR. VALENTE: We eddy currented.

MR. BARTON: Eddy currented, okay.

CHAIRMAN SIEBER: Now, your feedwater regulating valves have a constant differential pressure across them, and you control flow by controlling the steam on most of the turbines?

MR. MOLL: Yes, we have no feed water regulation valves. Basically we strictly control flow through the feedwater --

CHAIRMAN SIEBER: Turbines.

MR. MOLL: -- level control system by varying turbine speed.

CHAIRMAN SIEBER: Okay.

?: And then, once again, on the control side, incorporating the major mods that have been made on units 2 and 3, we are upgrading the feed water control system with a digital upgrade that is incorporating redundancy and fall tolerance control system.

Some of the mods we have -- removing mechanical linkage, motor speed changer, and motor governor unit, and replaced with a Woodward 505 digital governor, and final driver.

Time delay relays were added on for flow suction trips to eliminate nuisance spurious pump trips that we had had experienced in the past, as well as on the lou boll system we put in two hundred percent capacity AC pumps, and one hundred percent capacity DC pump, with diverse power supplies, to make it more fall tolerant, as well as the array of individual instruments that have also been replaced in upgrading the feed water system.

CHAIRMAN SIEBER: You said that you are using Woodworth digital governors?

MR. MOLL: Woodward.

CHAIRMAN SIEBER: Woodward, okay.

MR. VALENTE: Any other questions on systems?

MR. CROUCH: These were just three sets that we picked as an example. Safety system with a small amount of modification, a primary non-safety related system with an extensive amount of modification, then a system that had a large amount of modification.

This list of modifications that we handed out, every system has its own set of modifications, and if you have any particular questions on systems we can answer them. But we didn't figure we would want to take up your time, because it would take weeks, and weeks, probably, to go through all of them at this level of detail.

CHAIRMAN SIEBER: I'm sure that it would.

MR. BARTON: Just for information, the tubes in the water heaters are what material?

MR. VALENTE: I don't know, I don't remember. We can make a call back to the station and have that answer for you after lunch.

MR. CROUCH: I would recommend, at this time, this would be a good stopping point to stop for

lunch.

CHAIRMAN SIEBER: Okay. That is great, why don't we come back at 5 minutes to 1.

(Whereupon, at 12:55 p.m., the above-entitled matter was recessed for lunch.)

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

1:00 p.m.

CHAIRMAN SIEBER: We will come back in session now.

MR. VALENTE: Before we proceed on to page 19, there was a question that was asked, what was the material type on our feed water heaters. The material type is 304 stainless steel.

So moving on to page 19, we essentially completed the design for unit 1 restart in March of 2005. The design changes that were issued for unit 1 were driven by our design criteria, given fidelity issues, and other restart issues.

License renewal did not require any modifications on unit 1. To kind of cover the next couple of pages, we will go over some of the passive components that we replaced. I will tell you what we did, and the reason that we did it.

First one we have there is the condenser tubes. We replaced these tubes with stainless steel to eliminate the brass and get rid of the copper.

Extraction steam piping, it has been replaced for FAC. As Bill mentioned earlier this morning, we could have operated with the extraction steam pipe that we had. It wasn't extensive, but we

brought it up to unit fidelity to match the units 2 and 3 FAC program.

We wanted to keep everything consistent. The turbine cross-over/cross-under piping got replaced for FAC. GE supplied us an inadequate material on the original contract.

MR. CROUCH: For just unit 1.

MR. VALENTE: For just unit 1. We had a lot of tiger striping and we replaced it. The reactor building closed cooling water heat exchangers, these were replaced for economic reasons.

It was cheaper for us to replace the heat exchanger, in its entirety, vis a vis going after the two bundles and replacing those. And that is why we replaced them.

Dry well structural steel, this was changed out to support the design criteria. As Rick told you, we had change in spectra, pipe loads went up significantly, and components on the supporting steel, we had to essentially change things out.

Electrical penetrations, these were changed out for two reasons. One was for EQ purposes, and the other one was for appendix J. We had penetrations that were excessive.

Large and small bore piping primarily

changed out for FAC, IGSCC, and some nick issues, and for minor rerouting. Reactor pressure vessel, safe ends were changed out for IGSCC.

And the RHR service water, in the reactor building, this was changed out because of material condition. This was a lessons learned we had from unit 3. They had the laminations in there, we also had them. So that is all changed out.

Going on to the next page, --

CHAIRMAN SIEBER: Before you leave here, on the condenser tubes, what kind of biological control do you use?

MR. CROUCH: Condenser tubes?

CHAIRMAN SIEBER: It is an open cycle plant, right?

MR. CROUCH: Right, open cycle plant.

CHAIRMAN SIEBER: So do you use -- have you had any evidence of microbiological filing leakage?

MR. CROUCH: If you don't run the ammer taps you will have filing. But we run the ammer taps to keep the tubes cleaned out.

CHAIRMAN SIEBER: Okay. And you've already changed your condenser tubes?

MR. VALENTE: Yes.

MR. CROUCH: Yes.

CHAIRMAN SIEBER: Okay. Sometimes stainless isn't the optimum choice. But if you keep your system clean you are probably okay.

MR. CROUCH: And we have already changed the condenser tubes out on units 2 and 3, stainless steel also, so we are familiar with the operation of them.

CHAIRMAN SIEBER: Well, it is not safety related, anyway.

MR. CROUCH: That is right.

CHAIRMAN SIEBER: But some plants have not had the world's best experience. And the key is keeping the system clean.

MR. VALENTE: Page 20, if there is not other questions on that page, the dry well coolers were changed out, primarily, for reliability and reduction in maintenance time during the outages.

Our cable tray and conduit, and the associated supports, again, some electrical issues. We eliminated the ampacity issues by routing new trays and conduits. We got our separations for Appendix R.

And basically that was it. Pipe hanger installations were changed out. Design criteria 79-14 primary driver there. The GE in-vessel inspections,

we did the inspections, placed the access hole covers, inspections are essentially ongoing.

We did complete the shroud inspections, good results on the shrouds.

MR. BARTON: Any indications on the shroud?

MR. VALENTE: Yes, we had indications. No through-wall indications. Rick, do you want to expand?

MR. CUTSINGER: The shroud inspection, it was actually pretty good. I just got the data, but if you go through it, each one had 83 percent inspected, with no flaw. H-G weld had 81 percent with .4 percent of the inspected area having a flaw.

The H-3 weld had 88 percent inspection with no flaws, the H-4 had 90 percent inspection had 20 percent flaw. The 20 percent, the majority of the flaws were less than 10 percent, so they were pretty nominal flaws.

H-5 had 91 percent with 1.2 percent flaw. H-6 had 91 percent with no flaws. H-7 weld had 91 percent with 12 percent flaw. Once again, they are pretty small, they are like less than ten percent in range.

The Hotel-8 was a visual inspection, we

couldn't do the UT on that, and no detectable flaws on that one. And Hotel-9, which we had 19 percent inspection of the weldment, and no flaws identified there, either.

MR. BARTON: So what corrective action does that tell me I have to take, anything?

MR. CUTSINGER: No, it does not put into any corrective action form at this time.

MR. VALENTE: Torus coatings, torus was used to support the operating units with the water. We drained it during recovery. When we drained it we found some delaminations on the coatings below the water line.

We sandblasted all of that below the water line, bare metal, recoated with a qualified coating. So we had some damaged areas above the water line, we made isolated repairs on torus, so no problem with that one.

Cables, again, our cables were changed out primarily on the nuclear performance plan programs, EQ separation passed the voltage drop, short-circuit analysis. All these programs, and design criteria.

So, basically, that is what we had here. Nothing here, on these two sheets, was driven by license renewal.

MR. BARTON: How about the coatings on the containment itself?

MR. VALENTE: We have done some preliminary inspections. There are some areas that need to be repaired. Overall we are in excellent condition.

And as we complete out in the dry well we will close out on that aspect, and we will be recoated in the damaged areas.

MR. CROUCH: The real purpose of these last two slides has been, what Joe has been saying, these modifications were not driven by license renewal, but they are things that will be new components that are out there.

So they obviously support continued operation of the plant for an extended period of time. They are big passive components that will be new.

MR. LEITCH: With cables, you have talked quite a bit about instrument and control cables. What about medium voltage cables? I'm talking about maybe 4KV cable.

MR. CUTSINGER: The course break cables are being replaced. All we have is RHR and core spray, and then board feeders. Board feeders is already in service supporting the units 2 and 3

operation.

The RHR pump motor cables are being spliced and rerouted for Appendix R reasons, a portion of those are being retained. Obviously those will be tested before we do any splicing to those, to confirm the condition that they are in.

So that is really all that will be in scope for the medium voltage.

MR. BARTON: You are not replacing the whole cable, you are splicing the 4KV cables?

MR. CUTSINGER: Right.

MR. BARTON: Well, why don't you pull all new cable?

MR. CUTSINGER: We found it to be, the cables that we've got in there is perfectly adequate cables. And that having to be replacing, changing those out, we would get into other issues relating to conduit fail, and those sort of issues.

And since that is an imbedded conduit we did not want to risk the potential of damage on a larger sized cable, trying to fit it into that --

MR. BARTON: Isn't a splice a weak point that is subject to water, and moisture, and all that kind of stuff?

MR. CUTSINGER: No, sir, this is going to

be a fully qualified 50.49 splice that we are putting in. And we are talking about where the splice is going to be located, it is going to be located up in the ceiling of the reactor building, 565 elevation. So there will be no exposure to any moisture.

CHAIRMAN SIEBER: Well, there are qualified splices out there that you can buy.

MR. CUTSINGER: Yes.

CHAIRMAN SIEBER: On the other hand they are sort of technic-dependent. So whether they exhibit all the environmental and electrical qualities that you want is dependent on the expertise and the care of the workman who installs it.

MR. CUTSINGER: Like I said, we took the medium voltage splice kits through a full qualification program.

MR. LEITCH: Some of these, some plants have experienced problems with medium voltage cables. The breakdown of the insulation with phenomena called treeing.

CHAIRMAN SIEBER: Right.

MR. LEITCH: Have you experienced any of that in these cables?

MR. CUTSINGER: No, we have not experienced any of that. And that is more of a

phenomena when it is exposed to moisture.

MR. LEITCH: Moisture.

MR. CUTSINGER: And these are all in the reactor building, so that they are not exposed to that kind of environment.

CHAIRMAN SIEBER: So they don't go through trenches, or --

MR. CUTSINGER: They don't go outside the building.

CHAIRMAN SIEBER: -- manholes, or anything like that?

MR. CUTSINGER: That is right. Like I mentioned before, we do have some that are supporting common equipment, going down to the pumping station for service water. And those we did do some testing on, and verified that they were in good condition.

MR. LEITCH: But the routing from the, say for example, the diesels to the safeguard busses, and so forth, those kinds of cables are not below grade?

MR. CUTSINGER: That is affirmative, yes. They are not below grade.

MR. LEITCH: Thank you.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: Page 21 we have some other modifications refurbishments that we performed. The

first one up there is the control room design review modifications.

Again, this is primarily driven from regulatory TMI item. The recirc pump variable frequency drives, we replaced them on unit 1, again, for reliability and fidelity with the operating units.

And that is the same with the digital electro-hydraulic control system, again reliability and fidelity. The main generator rewind was associated with EPU. And, obviously, the rotor balance is just prudency.

The close in-fault protection of the switchyard, this was due to unit 3 operation coming in. And then the common accident signal, we had reinstalled the accident signal for unit 1, it was disabled when unit 1 was in lay-up.

MR. BARTON: What is that?

MR. CROUCH: In-plant, as Joe was talking about, we have -- it is a three unit plant. Unit 1 and 2 share four diesels. And so the way, and they have, each unit has like four RHR pumps, four core spray pumps.

And so since they come from the same electrical boards you have to, originally it was set up so that there is a potential where if accident

signals occurred in multiple units, the unit had to decide where the real accident was, and it would load the boards.

Well, we disabled that signal as part of unit 1 shutdown, to get unit 2 back and running. We have now gone and redone the circuitry and the logic so that it can properly handle a real accident signal in one unit, and a spurious accident signal in the other unit, without overloading the boards.

MR. BARTON: I understand, thank you.

CHAIRMAN SIEBER: With all these changes you are going to have to do a lot of testing prior to start-up, in your power escalation phase.

MR. VALENTE: Yes.

MR. CROUCH: That is correct.

CHAIRMAN SIEBER: I mean, it is going to be like a new plant.

MR. CROUCH: That is, essentially, what it is like.

MR. VALENTE: The remaining items, here, the reactor core isolation turbine reassembly and upgrade, and refueling bridge, crane modifications, these were driven by reliability and fidelity with the other two units.

Then the pumps and motor refurbishment

design criteria requirements for restart, same with the valves replacement/refurbishment. Again, nothing here was driven by license renewal.

CHAIRMAN SIEBER: I presume that your switchyard circuit breakers have all been sized to reflect the additional power, and the change in reluctance that the system presents to the plant?

MR. VALENTE: Yes, there was an extensive switchyard off grid study performed prior to the restart.

CHAIRMAN SIEBER: Does the plant control the switchyard, or does some off-site entity control it, or don't you know?

MR. VALENTE: Well, we hear that the switchyard, didn't we Dave?

MR. BURRELL: The plant owns the switchyard.

CHAIRMAN SIEBER: The whole thing?

MR. BURRELL: From the main banks, high side main banks in is station, make the transition on, I think for the switchyard as well, to the plant, as far as maintenance of the -- I stand corrected.

CHAIRMAN SIEBER: Maybe you should just step to the microphone so that we can hear you.

MR. R. G. JONES: Again, the plant has got

the responsibility for the transformer from the high side in. It belongs to the plant from the high side, from the transformer out, it belongs to TPS organization.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: And a detailed switchyard study, detailed switchyard study, and grid study was performed, and there was outfall from that, that we had to make modifications to.

CHAIRMAN SIEBER: Okay.

MR. BARTON: Do you do work in the switchyard without clearance of the control room? How do you guys control the work done out there?

MR. R. G. JONES: Again, this is R.G. Jones. The work is controlled, sir, by -- the TPS organization calls in and requests --

MR. BARTON: Who is the TPS organization?

MR. R. G. JONES: The TPS, I'm sorry, transmission power supply organization, they are also a Tennessee Valley Authority organization. They control the lines going out of the switchyard, as far as that.

And the other breaker, at the other end of the transmission line, is what belongs to those. So then, so if there is a maintenance request, if there

is maintenance to be worked on, they coordinate that through the on-shift operations group, and they coordinate the times that that is out.

MR. BARTON: Does the station engineering staff get to review any mods, or engineering work that the transmission people want to do in the yard? Do you get to review and approve it?

MR. R. G. JONES: Yes. All the work that is done in the switchyard is done to the station process and procedures, and they are all reviewed by the site engineering organization, as well as plant organizations.

CHAIRMAN SIEBER: All these big circuit breakers are controlled by batteries, the control system and trip coils, and so forth. Do you have procedures equivalent to station procedures for the maintenance of DC control systems on circuit breakers?

MR. R. G. JONES: There are similar controls that are in place for permanent plant equipment.

CHAIRMAN SIEBER: Okay.

MR. VALENTE: On page 22 here, for extended power uprate, actually there are 40 modifications that will be affected here, and we will discuss those a little later in the afternoon, here.

License renewal, I would like to reiterate, we factored in license renewal in the original design activities. And we had no modifications resulting from any license renewal issue.

Any questions on my discussions?

MR. LEITCH: Joe, earlier you indicated that there were 21, I think, was the number of tech spec changes. Where does that stand in the interface with the NRC, have those requests been made?

MR. VALENTE: Yes.

MR. LEITCH: And are they scheduled?

MR. MCCARTHY: That is correct, there are 21 tech spec changes total, that includes EPU, as one of those changes. Sixteen have currently been submitted, we have five approved, we have a couple we are still working on, or awaiting for a generic Safety Evaluation Report from the Staff.

That also includes our COLA, which one of those is also.

MR. LEITCH: Okay, thank you.

CHAIRMAN SIEBER: One quick question. There are requirements regarding lifting heavy loads with cranes. And when you look at license renewal many applicants evaluate the cranes as far as how many

loads has it lifted, how many times has it flexed, you know, what is the remaining life in the crane, what is the remaining life in the hook.

Have you done that kind of work?

MR. VALENTE: Yes, the reactor refueling zone crane was upgraded for dry cask work. And that evaluation was performed.

MR. BARTON: Is that a single failure crane now?

MR. VALENTE: Yes, it is. Same with our turbine building crane. We had made some heavy lifts, and we evaluated each one of those lifts, and performed the inspections.

CHAIRMAN SIEBER: Some of the cranes are only good for a certain number of lifts, you know, 40 lifts, or 100 lifts, or something like that. Have you looked at that?

MR. VALENTE: Ken is our project manager for license renewal.

MR. BRUNE: Ken Brune, license renewal project manager. Yes, we looked at those, that is TLLA, or the crane lifts, and went ahead and estimated the number of lifts we had, and the number of lifts we expected to have, made sure we ensured that they were under the crane manufacturer's limits.

CHAIRMAN SIEBER: And who is the crane manufacturer for the turbine building, and your reactor --

MR. BRUNE: Actually I'm talking about the CMA guidelines. They can answer to the manufacturer itself, but we looked at the fatigue, and the number of lifts, and made sure they were well under the limits.

CHAIRMAN SIEBER: Okay. I asked the question of who the manufacturer is because there is one manufacturer that has had some kind of a problem, that they had to file a Part 21 report, I think.

MR. CROUCH: Our cranes are Edever.

CHAIRMAN SIEBER: Okay, that is not the one, okay. Thank you.

MR. CROUCH: So what Joe has talked about, during this time, is the fact that we started the unit 1 recovery we were going to make sure we were going to use the same programs, processes, everything that was used for units 2 and 3 we've used the same methods for unit 1.

We tried to make unit 1 operationally identical to units 2 and 3 by installing all the same modifications, doing all the same upgrades as what had been done, either for restart, or for post-restart, up

until now.

It is a very large scope of modifications to do, as shown by this 40-something page of DCNs. It is a very well known scope, though, because we have already done it two times, this is the third time. So it is a well known scope.

There has been very little scope addition as we have gone through the course of unit 1 recovery.

CHAIRMAN SIEBER: Well, we don't expect the scope to be lock solid and firm at this point in time because stuff comes up.

MR. CROUCH: That is right.

CHAIRMAN SIEBER: On the other hand, the impression that I had, up until today, was that the scope was pretty fluid. So that would be tough for the Staff to evaluate as far as life extension is concerned.

But I think that the material you presented today sort of dispels my concern, to some extent, in that area. It does look like you have quite a bit of detail in what it is that you plan to do over the next two years.

MR. CROUCH: These upgrades and improvements, and basic DCNs that we are doing, they are being done to improve operational reliability and

to meet regulatory requirements.

They are also being done in order to implement extended power uprate. And, once again as we said, none of the DCNs, none of the design changes, were driven by license renewal.

But several of them by virtue of the fact that you are replacing large major components that have potential degradation, aging type degradation to them. Since they will be brand new they will support extended life for the plant.

CHAIRMAN SIEBER: Yes, but I'm sure you realize that once you replace it you have no operating history on the components you just installed which, you know, in the simplest form, in order to figure out how long a component will last, like a piece of pipe, you have to have its installed thickness, and you have to have another point, someplace along the line, so you can extrapolate out to a point in time where you need to do something about it.

And, to me, that is what so-called operating experience is, which we rely on for license renewal. So you are going to have programs, in place, probably more extensive than standardized programs to generate that kind of operating experience.

Even though the plants are functionally

identical, from a material standpoint they are not, from an aging standpoint they are not.

MR. CROUCH: Well, many of these material replacements had already been performed on units 2 and 3. So we are already getting operating experience on these particular materials, in this particular environment.

CHAIRMAN SIEBER: Okay. There are some exemptions to that of course, you know, flow accelerated corrosion, for example, is specific to the configuration of the pipe as well as the fluid conditions, and velocities, and so forth, in there.

So you can't just apply that across the board.

MR. CROUCH: That is right.

CHAIRMAN SIEBER: But, anyway, that has been a concern of ours in the past because these units have been, unit 1 at least, has been shut down for a long time, you are going to make a lot of changes, and you don't have this history on which you can predict the condition at the end of life.

MR. CROUCH: Any other questions for Joe?

CHAIRMAN SIEBER: I think you did a good job, and appreciate the fact that you not only are recovering the plant, but also recovered our schedule.

MR. CROUCH: Thank you. At this point in time I would like to invite R.G. Jones to come up. R.G. is our unit 1 restart plant manager. R.G. has been with the plant since, essentially, day one. He was an operator on the plant, back when unit 1 was started up.

So he has been around here for many years, and knows the intimate details of everything in the plant. He is going to talk to us a little bit about what we are going to do in order to return this plant to service, once we get it all modified, how we are going to make sure that everything is done before we turn it over to the operational side of the plant.

He is also going to talk to us a little bit about the restart test programs, how we are going to go through and test the plant. As you pointed out, this is a very large testing program, and he is going to talk to us about how we are going to scope it out, and how we will conduct it.

He is also going to talk about how we are then going to do the power extension testing, going from a shutdown reactor, all the way up to one hundred percent power.

One of the things that he is basing his discussion on, and you will hear him talk to the

various modes of operation. This is not referring to shutdown mode, startup mode, run mode. This is a baseline terminology, a design based on verification terminology that we use at Browns Ferry.

As we started through the baseline program for Browns Ferry, we have a document that is referred to as the Safe Shutdown Analysis. What this document did was it started back from the FSAR, and went and looked through, and found all the various events that Browns Ferry has to respond to, accidents, transients, and special events, it lists them all out.

It then went through, on a system by system basis, and determined what each system has to do, in order to respond to this particular type of event.

So, for instance, for a big event you needed to isolate your reactor, maintain a reactor coolant pressure, we listed as an event, closed the valve. If you needed an actuation of a system to inject water, that would be a mode of operation.

So what this Safe Shutdown analysis does, it goes through, for each system, and comes up with the modes. It also goes through and says, in order for this system to do its mode, it needs support from these other modes.

It may need electrical power, it may need air, it may need a signal from another system, whatever. So this document tells us how the plant talks back and forth to each other, from a mode to mode standpoint.

By doing it this way we are very confident that we know what to go test in the plant, so that we test the full progression, from the very basic functions up to the true safety related functions, to make sure that everything is tested.

So as RG talks about these, and when he starts talking about the modes of operation, that is what he is talking about, this Safe Shutdown analysis modes.

So with that I will turn it over to RG.

MR. R. G. JONES: Good afternoon. I would like to talk to you first on page 23, we will talk about the system return to service process.

And the process that we are going to look at ensures that all the tasks, everything we have been talking about up to this point in time, all the physical work that has to be done, all the engineering work that has to be done, that all of it has been completed prior to returning to service.

The piece of equipment, or the system that

we are going to be discussing, and talking about. The first thing is the engineering portion, maintenance is involved in that, modifications is involved in it, also operations and licensing.

What we will do, as we turn the page and look at it, we will see some of -- we will go into each one of these organizations, on what they do, and what their process is, and how they look at the system return service process.

One thing we need to note, before we do that, is that this same process that we are using to start this up, unit 1 up, was the same process we used on unit 2. We took those, with some lessons learned, and some enhancements that we saw from unit 2, applied it to unit 3, saw the results we got there, and that is the process we are using now for unit 1.

So it is the same process, we have used it on two successive times, both of them has been successful on doing that. And as of today we returned six systems to operation, using this process.

We did that as an upfront check for ourselves, to make sure that the process, and the individuals that we had working with the process, that they were familiar with it, because as we picked the piece up, as the bulk work draws to an end, and the

startup testing begins, at the latter part of the year, then we will start increasing the amount of testing, and we wanted to make sure that we had all the bugs worked out of the scope, and that everybody understood what the system, and what the process was.

So with that, we will turn to page 24. I think the last time that I talked to you all, I think I pulled out a drawing that was a little busy, and it looked something like this. I think you remember seeing that.

And I could tell, by the look on you all's faces, that I didn't spend anywhere near enough time on that to do justice that it needed. So what I tried to do is tried to simplify it just a little bit, still giving us time to talk about it, and we will talk about each one of the sections as we go through it.

But I think it better lays out how the return to service process works. And we will start up in the top left-hand corner, in what we call the system plant acceptance evaluation, or we call it the SPAE process, is our terminology that we use for it.

This is the design engineering input. So you've heard us just talk about the different modes of operations. What we do is we take each system and we say, okay, here is the system that we want to return

to service, this is the system that we want to SPOC.

And then we look at all the supporting systems that has to be there with it. If it is power, if it has air operated valves, that requires controlled air to be there, if it is coolant, raw coolant water, so all those supporting systems, and components.

Also we have to get ready, at the same time, that we get ready to run this system. So we have to have it in service to do that. So that is one of the things that this system plant acceptance evaluation does.

It looks at all of the systems, it looks at the components. And what it does, at the end of it, it gives us, in operations, a testable system that we can actually functionally test when we get through.

MR. BARTON: Sounds like we used to call a prerequisite list.

MR. R.G. JONES: In a sense, yes. That is exactly right.

So once we go through that, but it includes everything else. It includes all the modifications that is done, and with all the paperwork complete, it looks at all the couch, all the couch are drawn up, and any UVAs are looked at, and they are

taken care of at that point in time.

Either that, or they are excepted, and then exemptions are laid out there for us to be able to look at, so we will know what the exemptions are as we go through.

The drawings then are looked at and also any corrective action that has to do with that system will be included in the SPAE package. So we will know what the full scope of the work is, that is required, for this system to return into service.

The two bullets underneath that, then talk about what the two different functions that we have, as far as repairing, or refurbishing the system. The first one is a maintenance organization.

The maintenance organization, they do the like for like replacements. If we are going to take a globe valve out, and put a globe valve back in, and it is a like for like replacement, then the maintenance organization does that.

If we are going to modify the system, if we are going to take something that is there, and do something different with it, than what we had before, then it goes to the modifications organization, because they are used to working that type of work.

If we are going to reroute pipe, and run

it to a different place, if we are doing pipe replacement, a lot of times that could be done by maintenance, if it s a small group.

The large bulk work modifications, though, is mostly done --

MR. BARTON: Who are the craft people in the modifications box?

MR. R.G. JONES: They are the same, but we have a group, we have two groups under the maintenance mod supervisor. We have a maintenance mods superintendent. We have a TVA individual that works as a maintenance manager, and we have a TVA individual who works as a mods manager.

Under those individuals are contractors. We have Stone & Webster contractor under the maintenance organization, and we have Stone & Webster contractors under the mods organization.

For the maintenance --

MR. BARTON: Things that are in the -- the contractors under maintenance are qualified to do your plant maintenance? How are you sure that they are qualified?

MR. R.G. JONES: The biggest majority of the maintenance individuals that we have, that are in the supervision line for this right here, even though

they are contractors, were ex-TVA people that is retired.

So they had all the qualifications when they retired. Some of them were retired on Friday, came back to work on Monday as a contractor --

MR. BARTON: As a Stone & Webster --

MR. R.G. JONES: As a contractor by Stone & Webster, that is correct. But the qualifications are there.

MR. BARTON: But they are working to your procedures?

MR. R.G. JONES: That is correct, they are. So the maintenance organization takes care if any break or refurbishments that go on, they take care of that. So they are doing the break and refurbishments.

Whenever we get through with the motors we bring them back and the motors get one of two things. You have already heard Joe talk about it. We either refurbished, or we rewound all of our 4KV motors in the line, or replaced them, one of the three.

So they have all been taken off, sent to the power service shop and looked at, and brought back, and with the exception of the two that we had in service already, that was supporting unit 2 operations in the RHR pumps.

So all the valve motors have been taken off. They are back. And as they come back, these are reinstalled, and they are stroked. And just to make sure that the valves work, and everything works right on those, we go through that process of doing it, as we do that.

The maintenance also then, we do flushes, we are in the process of doing flushes. The reactor clean up system, which we will talk about a little bit later, but I will go ahead and bring up one of these now, to show you, essentially what we did with the flush.

MR. BARTON: Who does the flushing?

MR. R.G. JONES: It is done by unit 1 operations, and the systems engineering organization for unit 1. We have, and this is Mr. Moll's organization that helps us with that. But we just finished up doing the flushing on the reactor water cleanup system, all new piping.

So we took off one of the strainers, right there at the inlet, and we hooked up a two inch line, and flushed a lot of water through there to make sure everything was cleaned out before we put the pumps in service, had them in service, had to stop the pumps after initial start, twice, in order to clean that

filter out:

We had a pretty fine mesh strainer on the inlet coming into the strainer.

MR. BARTON: So all equipment that is operated by operations with maintenance support?

MR. R.G. JONES: That is correct, sir.

MR. BARTON: During flushing?

MR. R.G. JONES: That is right. Unit 1 ops is also a group of individuals that are currently licensed. I have 14 currently licensed SROs that work for me on unit 1 recovery. So 12 of them, out of the 14, were ex-shift managers.

So they understand the systems and they work closely with the operations group on-shift. If it is a system that affects anything in an operations unit, then we get those, we go through, and work our way through their organization, to make sure that they fully understand it.

If it is totally outside of those, like the reactor water cleanup system is, then we coordinate it through the control room, because the unit operators, in the control room, do work for the shift manager, who is on shift.

CHAIRMAN SIEBER: When you accept a system who is the final person who signs off? Some operating

supervisor?

MR. R.G. JONES: The individual that signs off, we have two phases that we go through, Mr. Sieber. The first one is a SPOC one sign off, and all that is saying is that we got the systems done and ready for testing.

SPOC two is the final sign-off, and it has a checklist on it. And that has the operations side, the operations organization, and the system engineering organization from unit 1 side says we have everything done, and then I think Rich is the final sign-off from the plant, for acceptance of the systems.

MR. LEITCH: So as you come out of SPOC phase 1, as you come out of that block, all the physical work should have been done?

MR. R.G. JONES: Yes, sir. And that is what this SPOC one does. The SPOC one is physically a checklist, is what it really is. And you work up to this checklist, is what you are working.

And what you are doing is you are saying all the design work that I said I was going to do, mods has completed all the design, and they either did a static, or some kind of dynamic testing, to verify that, therefore, that the design works like it should.

One of them that we will talk about, that we just sort of lived this, is we did, in this common access logic, where we had gone in, we actually went to unit 1 and dropped out all of unit 1's wires.

We lifted the wires from unit 1's aux extension room. Well, we were still hot from unit 1, and back to unit 2. So if we had gotten into something in the unit 1, and shorted out some wires, we could have actually done some tripping on unit 2.

So during unit 2's previous outage, that they just went through, we went in and disabled all the wires on the unit 2 side, came back, did all the testing to make sure that what we did on the wire lift didn't affect anything that they did.

So we now are separated, completely, from unit 2, and it allows us, it turns us loose now to do our logic, and get it lined back up. And that is one of the things that we did on this past outage.

So we have looked at everything, unit 2's outage, this past one was, could very well be the last one that we will be able to do, that would require them to shut down. So we looked at everything that we had, as far as design space, to make sure that there was nothing, no other designs that we had, that would require us to have unit 2 off-line in order to be able

to do those.

And we completed those in this past outage at unit 2, that was just done.

MR. LEITCH: So when you come out of phase 1, SPOC phase 1, the wiring has been all wrung out? I mean, we know that the wires go where they are supposed to go?

MR. R.G. JONES: That is correct.

MR. LEITCH: And that type of, what I would call, static testing, or checking out the circuits is all done?

MR. R.G. JONES: If there is any instrumentation that was replaced, all the instruments have been checked out, they have been calibrated, and we know that they function like they should.

All the valves have been stroked, so if we changed a motor operated valve, we stroked it, timed it, and made sure the timing and the stroke on it was okay.

All the corrective actions done, all the drawings are complete. So what we said we designed it to, and what we go through, they are done, and all the primary criticals are then in the control room, they are done, so it is ready.

And all the procedures, for that system,

are complete. And that is operating instructions, all the surveillances, all the tests that has to be run. If there is any special test that we are going to run, as we go towards SPOC 2, or phase 2 of this right here, that is also ready at that point in time, too.

MR. LEITCH: So now who accepts the system as you come out of phase 1, there, who? There has to be some signatures there, who is that?

MR. R.G. JONES: The signatures are mostly in the unit 1 organization. They belong to Bob Moll in the engineering portion of it, system engineering, I'm the final signatory, as far as phase 1 SPOC, along with the running operations manager, also signs off with the shift manager.

But all that says is we are now ready to test the system. We have all the mod work done, we have all the maintenance work done, and we are now ready to test the system. And we have all the procedures --

MR. LEITCH: And you have already tested it, what I would call static testing?

MR. R.G. JONES: Some static tests, that is correct.

MR. LEITCH: Okay.

CHAIRMAN SIEBER: What happens if it

flunks the operational test?

MR. R.G. JONES: We just go back, for reactor cleanup system we will stop, see where we are, see where the fault occurred, go back and replan, if we have to do some additional mods. Because since we missed, we haven't done this yet, we haven't run across that issue.

CHAIRMAN SIEBER: I'm thinking about what the process is, you know, some plants have a joint test group that evaluates the test, decides whether it is a pass or a failure.

MR. R.G. JONES: We call it a restart test group, is what we have.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: We do that once we get through with, in other words, when we get through with the testing, we will have a joint test group that stops and looks at all the testing, make sure all the data we have, everything meets --

CHAIRMAN SIEBER: Well, you have to be doing this as you go along, because each subsequent test relies on the ability of the system to do the previous test.

MR. R.G. JONES: That is correct.

MR. MOLL: Bob Moll here. Phase 2 SPOC

checklist, and RG will describe it later. But there is certain testing we are doing between phase 1 and phase 2, it falls underneath the restart test program.

And one of the sign-offs is, is that once that test is completed, that procedure, and the results of that test, is brought back to the joint test group for, who has already approved that testing for that system.

The results for that testing have to come back to the joint test group who review that and says, yes, the acceptance criteria was met, and we close out the restart, Bill will sign that off for that system.

And that is, really, how that process is handled. The only other exemption to that is some of the restart testing for a system can very well be a power to power extension testing.

For instance, the high pressure coolant injection system, one of the restart tests is a cold quick start from standby conditions, to verify it comes up to 5,000 gallons a minute.

That testing can only be done during power extension. So that would be deferred to a later date, and carried in the schedule.

CHAIRMAN SIEBER: Do you use your regulation corrective action system to identify and

track test failures?

MR. MOLL: That is correct.

CHAIRMAN SIEBER: And so there will be a huge amount of discrepancies that show up in the system, because of the large amount of testing that you are doing? Huge is a relative word.

MR. MOLL: Well, I will tell you that we will have some test efficiencies. I'm expecting those to be minimal, as long as we design it, and install it correctly, then when I go run these tests I should have minimal issues.

But any problems that do come up, that is what we call test efficiency, it is documented in the corrective action program and that drives the solution to that. And we do track those from the joint test group.

CHAIRMAN SIEBER: And the system doesn't get signed off until those are cleared?

MR. MOLL: That is correct.

CHAIRMAN SIEBER: Somebody sit down and say that doesn't make any difference?

MR. MOLL: No, that has to be reviewed by the joint test group, to agree with that, and that is a sign-off in the SPOC process, also.

CHAIRMAN SIEBER: Okay, thanks.

MR. BARTON: Could you proceed from phase 1 to phase 2 if the labeling wasn't complete?

MR. MOLL: Our goal would be to have one hundred percent labeling done. That is an ops sign-off. As long as ops can -- as long as the labeling is adequate for us to continue on with testing, it could go without labeling being one hundred percent complete, that is correct.

MR. BARTON: But would it then have to have a temporary tag, or some temporary label?

MR. MOLL: That is correct.

MR. BARTON: But permanent labeling could be a deficiency carried on until some time later?

MR. MOLL: If we didn't have the permanent labeling done, we would have a temporary label out there, in place of that permanent label.

MR. BARTON: You would have a deficiency?

MR. MOLL: Right, at phase 2 SPOC sign-off all permanent plant labeling would have to be one hundred percent complete.

MR. BARTON: Got you, okay.

MR. R.G. JONES: The statement says, labeling reviewed and dispositioned. That is what Bob was saying, that is the terminology. When you go look at the phase 2 SPOC sign-off, phase 2 SPOC doesn't

give you that option, it says it has to be done.

MR. BARTON: It is complete?

MR. R.G. JONES: Yes, sir.

CHAIRMAN SIEBER: So I can assume, from that, that there are, every label that is required on units 2 and 3 is in place?

MR. R.G. JONES: Time for another site visit?

CHAIRMAN SIEBER: Yes, give me a year.

MR. R.G. JONES: I want to answer that with an affirmative, that is correct. And we are in the process, we have a process, we are looking through right now, in fact, we have a pretty elaborate system for it, for doing the labeling.

So I wouldn't be surprised --

CHAIRMAN SIEBER: Yes, that is usually a lifetime job for a couple of people. It never ends.

MR. R.G. JONES: The restarts give you a whole different perspective on being able to label the plant than you would have if you had a plant that was operating all the time, and running. When you have been shut down you can pretty well go through that.

So we take it system by system, and it goes right through the system.

CHAIRMAN SIEBER: Okay, thanks.

MR. BARTON: At what point in this process, and how, does quality assurance, or whatever you call that function become involved?

MR. R.G. JONES: Quality assurance, quality control is in the process, depending upon the complexity of the work order, or the modification, and there are certain hold points in our QC hold points, based on what the requirements are for that.

So that is built into the system. We also do quality assurance on this, and they come up, they have looked at the six systems that we just completed, just recently.

And with some findings out of this, we asked them to do an assessment based on our going through the first six systems, to make sure that they were in agreement with the process, how the process was laid out, and what we did was okay.

And I know that we had no findings for that.

MR. BARTON: So they have reviewed the process?

MR. R.G. JONES: The process, yes, they did.

MR. BARTON: Okay.

CHAIRMAN SIEBER: Do you have an

engineering assurance function in your organization? Somebody that goes over calcs to make sure that there is no mistakes?

MR. R.G. JONES: That is done in-line by the final organizations.

CHAIRMAN SIEBER: Do you mean the supervisor checks the worker?

MR. R.G. JONES: No.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: The worker is checked by another qualified worker that has all the proper qualifications.

CHAIRMAN SIEBER: Another engineer?

MR. R.G. JONES: Another engineer. A supervisor does a review for approval, but it is not for a QA check.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: There are QA surveillances on calcs.

Also for the system pre-operability phase one checklists, one of the things that we look at there, like I said, it is after the completion of all items that are required for system testing.

So we say that we got all the system testing, we got all the items walked-up. So the last

thing that we do, we do a complete walk-down of the system at phase 1.

And with that we are looking at the physical condition of the system itself, and to make sure that since we have been working on it, and since it has been out in the plant, that there has not any damage been done to it, where you've got instruments, instrumentation lines, whatever.

Anything like that has been taken care of. That gets looked at in this right here. Those are written down, and then they get dispositions, along through the processes, as we go through the process for that, before the sign-off.

MR. BARTON: But you are doing a lot of, what was I going to say here? With system mods you are doing a lot of inspection on those mods, as you are putting the systems in service, you are doing a lot of system flushing.

Are you doing any pressure tests, or are your pressure tests going to be at operational, while the system is operating, or operational leak tests? What are you doing to verify integrity of the system, what kind of testing are you doing there? What are you doing for pressure integrity?

MR. MOLL: Some of these modifications we

do would require a hydrostatic test, fire protection header is one, so that gets a hydrostatic test. The large majority of our leak tests will be in-service leak tests.

MR. BARTON: The operational leak test?

MR. MOLL: Right, with the system in service. Either the pump running and we walk it down and do a leak test, those kinds of test.

CHAIRMAN SIEBER: Well, you do have some things that have to be hydrated.

MR. MOLL: That is correct.

CHAIRMAN SIEBER: Well, that is pretty standard.

MR. R.G. JONES: And all the valves that we are putting back in, that requires local leak rate testing, we have done an unofficial local leak rate test on those to verify that they do meet the requirements as we go through.

CHAIRMAN SIEBER: And your testing will test every function the system is supposed to perform?

MR. R.G. JONES: That is correct.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: So once we get the walkdown of the condition of the system, then we are ready to start in the testing portion of it, and that

is what phase 2 SPOC does.

Phase 2 SPOC then takes the surveillance test, it takes the restart test program, it looks at each one of the different functions that we said that each one of the systems is supposed to perform.

And we will go through, do all of the tests. At this point in time there is, we get configuration control of the system, for testing, not the final configuration control, I'm sorry, status control is what -- as far as operations is concerned.

We get status control of the system so we know where we are going to be putting water, or air, depending upon what it is, and where it is going. And at this point in time then we start the testing program, and we go through tests.

At the end of that, we will stop and we get a system engineering recommendation for operability, because we will see, and we in unit 1 will recommend to the plant, that this system is now ready for operability to be declared. That is a shift manager's responsibility, when he gets ready to do that.

And we will be able to go to work control, and they will be able to say that all the PMs are in periodicity, that all the surveillances have now been

completed for that system to prove it is operable.

Even though we might not declare it operable at this time, and we will also put those surveillances in periodicity at that point.

MR. BARTON: Who are your test engineers?

MR. R.G. JONES: Our test engineers, currently right now work for Bob Moll. They are all contract personnel. A lot of those individuals worked on unit 2 recovery, and also on unit 3 recovery.

MR. BARTON: But it is a contractor?

MR. R.G. JONES: Yes, they are.

MR. BARTON: Reporting to who, who do they report to, in house?

MR. MOLL: They report to me, it is Bechtel Engineering. The other thing we have done is all of the system engineers, restart test engineers, that work for me, have the appropriate ANSI qualifications, and they have all completed the Browns Ferry, Tennessee Valley Authority system engineering ESP training program.

MR. BARTON: Thank you.

MR. MOLL: The ESP training is the INPO accredited training program for engineering on-site, basically a systems training, some simulator training, and a regular classroom training that a permanent TVA

engineer, system engineer would go through.

MR. BARTON: So one of your contract test engineers does not have to go through that portion, right?

MR. MOLL: No, they have been all through that training, and have all those qualification cards signed off, just like the permanent TVA staff.

MR. BARTON: Okay, thank you.

CHAIRMAN SIEBER: I think you said that you may accept the system with temporary labels?

MR. MOLL: That is correct.

CHAIRMAN SIEBER: Would you accept a system that doesn't have all the installation installed? Or all the coatings applied?

MR. MOLL: Let me tell you, with the insulation, we might not put the insulation on at the current time. Some of it that requires hydrostatic testing. If you put the insulation on you have to wait four hours versus a very short period of time if you have no insulation on them.

But we are --

CHAIRMAN SIEBER: But after the hydro would you wait a year before you put it on?

MR. MOLL: No, sir.

CHAIRMAN SIEBER: Okay. I'm trying to

figure out what acceptance really means. And how complete must the system really be. There are a lot of finishing touches that --

MR. R.G. JONES: Let me tell you what that entails. I have been a plant manager twice, and I know what it is to have a nice running clean plant. And that is what we are going to give them back.

If you look at, I think we had let you see the fuel coating system, which was the first system we returned back to service to the plant. And one of the requirements, in the checklist, is that the area is painted, all equipment is painted, and it is back to the original specs.

We didn't paint it the first time, so it looks a lot better than it did. With the color coding in there, of the system. The floors, and everything, will be the last thing we do. We are going to wait until the last to get that.

But all of the equipment in the area, right there, will be cleaned up, painted, insulation on before it is turned baCK over.

CHAIRMAN SIEBER: Okay. I noticed you had a lot of star glaze around, which I think is on your floors, which I think is a great idea in a BWR, in any kind of a plant. That certainly helps radiological

condition situations. So that is good.

MR. R.G. JONES: On page 25 of the restart test program, again, reiterating what Bill said, the reason why, and our purpose is to verify that the systems are capable of performing their safe shutdown analysis and our safe shutdown requirements for each one.

And that they do operate within what our licensing basis is. So our commitment to NRC is to test the safety related mode to the systems. And that is what we will be doing with the restart test program.

Our non-safety shutdown functions, we do that through our post-modes testing, and also our component testing that we have. And, again, it is just like the restart test program we had for units 2 and 3.

We do have a lot of oversight in the testing program, that we have had, and with current work that we currently have in place right now. Nuclear assurance does look and do assessments of our systems.

In our return to service they look at the work that we are doing. We have a restart test group that will be looking at the tests, as the individual

tests start coming in. They will be reviewing the tests.

You heard Bob talk about that already. Also the plant operations review committee, which is or plant organization that sets, that has the plant manager as the head, will be the group that will be looking at that from the plant operation review committee, or the operations manager, the plant's manager is the last signature.

And then the nuclear safety review board, of which is also overlooking that. And we do have, now, have set up a separate unit 1 subcommittee for the nuclear safety review board to be able to also look at some of our activities that we are doing currently.

MR. BARTON: Are they going to be on-site, is this a group that meets periodically, or --

MR. R.G. JONES: They are going to be meeting periodically with us, on a quarterly basis right now.

And we also, like we said earlier, we have two NRC full time, two NRC resident inspectors on-site, that are assigned to unit 1.

MR. LEITCH: I assume the testing proceeds in accordance with a procedure, with pre-prescribed

acceptance criteria?

MR. R.G. JONES: Yes, sir. All the surveillances, our surveillance tests are just like what you would have from tech specs, where it says here is the criteria, we have acceptance criteria in the test and it is either a go or no-go, when you get to that point.

MR. LEITCH: Yes, for surveillance tests. But I would assume in this restart test program you are doing tests in addition to the normal surveillance tests?

MR. CROUCH: Why don't we let Bob describe the restart test matrix.

MR. MOLL: The restart testing, I guess if you look at a sequence, the design guys define what needs to be tested, and what the acceptance criteria is.

My guys job is to take and translate that, and they develop a document that identifies what the testing mode is, what the acceptance criteria is, and the procedure that is going to be used to go test that.

Now, those procedures are either a surveillance instruction, that I a permanent plant document, that we will go do. It is either a

surveillance requirement, again, which is a permanent unit 1 plant document that implements the tech spec requirements.

If there is testing that we can't do within one of those two procedures then generally if there is a post-mode test, I've already written, that captures those requirements, I will use that, or we are developing, we call them TIs, or technical procedures, that basically it is in the same format as the surveillance instruction.

It has the defined acceptance criteria, sign-offs, completed step by step that would direct that testing.

MR. LEITCH: Okay, thank you.

MR. R.G. JONES: Page 26. What we did here, was we took the same three systems that we talked about, that Joe Valente talked about earlier, and we are going to show you what the testing is, and what the requirements are in the system modes that you see down there at the bottom.

We will go through those very quickly. This is ECCS, this is the one that, remember, it had the minimal amount of work done to it. The post-mod testing and calibration and surveillance is included in the valve stroking and timing.

The local leak rate test, did all the leak tests on that, the component calibrations, any calibrations that had to be done for instruments, whether they were put in new, or whether they were there, and existing.

Then we will do a cold quick start. This cold quick start will come as a result, and after we have reached rated pressure and temperature on the reactor vessel.

And it will also, after some point in time, between 55 to 75 percent power, also do a vessel injection. And this allows us to do the tuning on the HPCI system.

So it gets, so to start off with we will have an aux boiler run. So we have the ability to take an auxiliary boiler, and we will have the HPCI system operable, prior to startup.

So we will be able to test it up to 150 pounds. And then we are required, when we get to 150 pounds to test it. And then, again, at rated pressure and temp, we will run it again at rated pressure and temp.

Then once we get through with that, then we will set it up, let it cool down for 24 hours, and then we will run a cold quick start, which verifies

that it meets the minimum time that it can come up to speed, and that it runs.

So that is the testing that is done with that. That tells you, down here, the system modes, one of the first system modes that initiates on low water level. This sets that up.

And the second one talks about the flow rate that it gets within the time period that it is supposed to get it. You want to make sure that the minimum bypass valve functions as it should.

And then when they get an isolation signal on the steam, that the steam signal is isolated, as it should. So all of those functions will be tested. And we can do that, we do that through surveillance testing.

And that will complete the testing on the HPCI. Any questions about that?

(No response.)

MR. R.G. JONES: Page 27, reactor water cleanup system. This is the one that we complete redid. The functional testing on it is the same. We have pump interlocks that looks at valve interlock for suction protection.

We will also be stroking and timing of the valves. We will do local leak rate testing on the

valves, because they are primary containment isolation valves that we replaced, that has already been taken care of.

We have already done the unofficial local leak rate test on those, and we will also do component calibrations. The system modes on this one are strictly isolations, that is what it looks at, when you look at it.

Where you get a primary containment isolation, where you get an isolation of the standby liquid control initiation, or where you get a high area temperature that would cause the cleanup system to isolate. That is the functions that that serves.

MR. CROUCH: One of the questions that came up, from one of the members, was what tests normal operational functions? Like on a system like this, reactor water cleanup, if you look down there at the bottom, the three functions calls out, it has nothing to do with filtering water.

CHAIRMAN SIEBER: That is true.

MR. CROUCH: So that function of the system is tested by the other component testing that we will do, separate and apart from the restart test program. From the restart test program, we are just testing the safety modes, the non-safety related modes

are tested as part of the component testing.

CHAIRMAN SIEBER: It would be nice if it filtered water.

MR. LEITCH: Is there an isolation on the differential flow?

MR. CROUCH: No.

MR. LEITCH: No?

MR. CROUCH: Some plants use that, but we do not.

MR. R.G. JONES: On page 28 we took the feedwater system and the surveillances on the feedwater system, that we will be talking about, this right here, when you look at it, you would think feedwater system, you think the water going into the reactor vessel.

This also is the one that supplies all of our control instrumentation to the three element control, as far as water level control. And this is where this is taken care of.

So we are talking about, we do functional testing on the feedwater control system. We will discuss that a little bit later, when we get over into the sequence.

And I will show you where that occurs. This is the place where we do zinc passivation on the

system. We use the delta P across the feed pumps in order to place the zinc in the system.

And we will also do component calibrations in, again, the system leak testing. The system modes, as you can see down here, is to verify that on the low water level, that it sends the signal to do a lot of things.

One is to start your emergency core coolant system; one is the primary containment isolation system, isolation, and it also gets the main steam line closed on low water level.

MR. BARTON: What is the zinc passivation system? I didn't think you had that.

MR. R.G. JONES: We do. Yes, sir. We do have it on units 2 and 3 and we will be placing that, in service, on unit 1 when it goes into operation.

MR. BARTON: I thought all you were doing was hydrogen water chemistry during startup. I didn't know you were doing zinc injection.

MR. CROUCH: We are also doing zinc injection, use depleted zinc oxide.

MR. R.G. JONES: On page 29 --

MR. LEITCH: Just one thing. What are you talking about here? For example, just to go back to reactor water cleanup for a moment. This whole

section here we are discussing what you call the restart test program, right?

MR. R.G. JONES: Right.

MR. LEITCH: So, now, as I understand it, in reactor water cleanup, you've got totally new pumps, and they are cold pumps now, rather than hot pumps, totally different location in the system.

MR. R.G. JONES: Same as units 2 and 3 has.

MR. LEITCH: Yes. Where do you verify that those pumps run and pump water? Is that part of this reactor water, is that part of the --

CHAIRMAN SIEBER: It is not a safety --

MR. R.G. JONES: -- talking about, that is part of the non-safety related functions that you will test through component testing.

MR. LEITCH: And where does, in this flow diagram that we discussed earlier, about SPOC and so forth, where does that occur?

MR. R.G. JONES: That occurs after phase 1 SPOC, and prior to phase 2 SPOC sign-off. See, phase 1 SPOC says that we have all the maintenance performed, I have all the procedures ready, and I'm ready to test.

That is really what phase 1 SPOC says, I'm ready to test. Then the testing begins, and the phase

2, at the end of phase 2 SPOC you will say I'm tested, I have everything tested, and I'm ready to declare the system operable.

CHAIRMAN SIEBER: From a safety standpoint?

MR. R.G. JONES: From a safety standpoint, correct.

CHAIRMAN SIEBER: But it doesn't need to filter water.

MR. R.G. JONES: Well, with the filtering water part comes, what we call the PMTI, it is a post-maintenance test instruction.

CHAIRMAN SIEBER: Right.

MR. R.G. JONES: And we just finished up with the reactor water cleanup system, verifying what -- we ran with new motors, and new pumps. The first thing we did we ran them uncoupled, we ran them uncoupled for a while to make sure that everything was okay, the vibration is all right, and everything.

Then we coupled them up and then we ran them for a period of time coupled up, to make sure that the flows and everything were okay with them. And we shut them back down.

So we currently have them shut down.

MR. LEITCH: Now, that is what you call a

functional test.

MR. R.G. JONES: That is correct.

MR. LEITCH: Now, take me back to slide 24 and show me where that functional test occurs. Is that in this final --

CHAIRMAN SIEBER: It is not in any of those blocks.

MR. CROUCH: It doesn't say functional test, RG has just described it for you, where it occurs.

MR. LEITCH: And that is between phase 1 and phase 2?

MR. R.G. JONES: Yes, sir. Phase 1 says, again, I'm ready to test. At the end of phase 2, phase 2, this SPOC, what we call phase 2 SPOC, we don't say that we are in phase 2 SPOCing a system.

What we say is we are finished up with phase 1 SPOC. So we can call it a completion, it is a milestone, we have a date for this. So let's say it was today, we will say we are done with that.

We are now beginning to test. And we say we are going to complete, we are going to do complete phase 2 at this date here, which means between this and the phase 2 date, that we are doing nothing but testing.

And that is going to -- where all the tests are required to be tested, whether it is surveillance test, or whether it is in our restart test program, which is where this one would show up.

Then this is where we would do this. And that is where we find out whether or not it is going to filter water in this part of it right here.

CHAIRMAN SIEBER: When you give this presentation, again, you will have to come up with a third chart.

MR. LEITCH: Okay. But this says, in phase 2, it says restart testing. And if we are applying this diagram to reactor water cleanup system, this slide 27 describes the restart test program for the reactor water cleanup system, right?

MR. R.G. JONES: That is true.

MR. LEITCH: But, once again, that doesn't assure me, I'm just trying to make sure I have this straight. That doesn't assure me that the pump pumps, that the pump turns, it just assures me that the safety interlocks are satisfied?

MR. R.G. JONES: That is right.

MR. LEITCH: Okay. So we could get all through that without the pump, you know, with the pump bound up. I'm not saying we would like that, I'm

saying, I'm just trying to understand the process.

MR. MOLL: RG, let me take a shot at this. The restart test program, that is the I've committed to the NRC to do the testing in that program, and that is a very small piece of testing that has to happen at Browns Ferry for recovery.

Now, between phase 1 and phase 2 SPOC there is a big box. And any testing that has to be done, on that system, is completed between phase 1 and phase 2 SPOC.

The only exemption would be if I can't do it because of plant conditions, and I need power extension testing, and I have scheduled it out. So within phase 1 and phase 2 SPOC, one piece of testing we have to have done at phase 2 is the restart test program.

And in all honesty that is the big, that is a very small piece of testing. The testing you are talking about, to make sure that those pumps pump water, these pumps were brand new, put in under a modification.

The post-mod testing, and the testing that we have done to verify the pumps pump water, that has already been completed, and that was a post-mod test we ran.

There is also a post-maintenance testing that might be done, if it is a maintenance item, but again, that is generally using a current plant procedure that exists, that may be electric cycling of a valve, that kind of stuff.

But any of that testing is completed between phase 1 and phase 2 SPOC. Restart test program, that we are describing in this presentation, is really the testing that has been committed to the NRC to do, to recover Browns Ferry unit.

And that is a very small piece of the testing that any of these systems will undergo.

MR. LEITCH: Okay, I understand.

MR. DELONG: Also, Rich DeLong, site engineering manager for the operating units. The other piece is, before we sign off, as the operating unit engineering organization, we already have reviewed, and buy into the scope of the testing program, for any given system.

And then, also, sign off acceptance of the test results, and the condition of the system, at the end of the SPOC phase 2, our signature is required prior to operations and plant manager's signatures.

MR. LEITCH: Thank you.

MR. R.G. JONES: I will do a third attempt

on that.

(Laughter.)

MR. R.G. JONES: Page 29 phase 1 testing. What we have done is we have got the testing of the power extension program, and it starts from the open vessel testing all the way up to one hundred percent power.

And we have it in four phases. And the reason why we put it in four phases was to allow us to stop and have management hold points at each one of the phases. And they have some rhyme and reason to why we have them there.

And we will talk a little bit about what is included in that phase 1 testing, and then they will all have this bottom part down here that says that there will be a management assessment of the test results, and the plant operations review committee, and the plant manager approval, prior to proceeding.

So we've got a procedure that is lined up for that, some technical instructions that will work through this right here, to make sure that all this gets done, and it will have signature sign-offs on that, and the plant manager will approve.

And once he approves this, then we will go from phase 1 into phase 2. So the first part of the

testing is what I would call sort of open vessel testing, to start with.

And then we start closing the vessel up, because we do SRM, RM, range monitors, to make sure you have your range monitoring systems available for you.

And then we do control rod drive testing, which is nothing other than just a friction test, prior to setting the head, to make sure that when we load fuel, and prior to setting the head, that we have no bundles that are misoriented, anything is taken care of, and then we haven't set something down and got it to where it is in a bind.

So we do friction testing on all the CRDs. One that is completed, and we will go ahead and button up the reactor vessel. We do two things, we do a reactor vessel hydrostat test, and that will be done.

At this time we do leak checks, and we do hydrostat testing, for this time one would do a hydrostat test, and take it up all the way to 1120. And then we will also do a containment integrated leak rate test, also at this point in time.

And that is the big test, that is the 50 pound, approximately 50 pound test that we run on the containment, that we will be running, also, during

phase 1 testing.

We also run HPCI, our high pressure injection, and our RCIC, which is our low volume, it is still high pressure, but it is lower volume, it is 660 GPM versus 5,000 GPM for HPCI.

We will run that on the auxiliary boilers to make sure we have that ready prior to startup. And also the backup control panel testing. All the components on the backup control panel will be tested and fully functional prior to coming out of phase 1 testing.

Go through the management assessment -- yes, sir?

MR. LEITCH: How long would you expect that phase 1 test to last, like a month? I mean, are we talking days or weeks? I mean, just --

MR. R.G. JONES: Right now I think we have about three weeks set aside for this portion right here.

MR. BARTON: There are a couple of biggies in there, containment integrated and reactor vessel pressure --

MR. R.G. JONES: We have a lot of experience on running these things.

CHAIRMAN SIEBER: You have nine days right

there.

MR. R.G. JONES: We have about three weeks, right now, currently set in --

CHAIRMAN SIEBER: So the answer to the question is yes.

MR. R.G. JONES: Yes. Okay, phase 2 testing, we will go to page 30. This takes us up from startup to 55 percent power. We picked 55 percent power because that is the point that we will have all the balance of plant equipment in service.

So everything will be in service at 55 percent power. So there is no pumps on standby, up until this point in time you are waiting to get the third condensate booster, and feed pump in service.

This puts them all in service, so everything now is ready and there. So we will go through our initial criticality and shutdown margin testing. SRMs, I won't read all of these.

The ones that are of interest, down through here, will be the thermal expansion walkdowns. That takes place inside the dry well. What this is, is around 150 pounds pressure, and as we start pressurizing, and the temperatures starts coming up on the reactor vessel, we will make sure that everything is going like it should.

And we went through this on units 2 and 3, and we will have the same, as we go through it on unit 1.

CHAIRMAN SIEBER: You expect no surprises?

MR. R.G. JONES: We expect no surprises. Based on what we have seen, based on -- we were pretty good on unit 3, as far as what we had. Unit 2 we learned some stuff on the way, unit 3 we had a pretty good handle on it, from the -- and we expect that we will take the lessons learned that we had off of unit 3.

CHAIRMAN SIEBER: How are you going to do that, you are going to measure things, or --

MR. R.G. JONES: We measure, the biggest part was the opening in the gratings, and things that we had. But some of it moved a little bit in a different direction than what we thought, initially.

CHAIRMAN SIEBER: Yes, okay. Well, the important thing there is to make sure that all the supports are installed in the right direction, then represent an untoward constraint, you aren't breaking snubber shafts, and things like that, which could occur if it is not done properly.

MR. R.G. JONES: Our reactor feedwater overspeed testing, and balancing, also takes place

during this part of the startup. We are not able to run our feed pumps prior to startup.

However, we don't need our feed pumps until we get to around, to ready pressure and temp. We are able to use the CRD system to do that. And so at that point in time.

So this gives us the ability, then, to go ahead and do the overspeed testing, and the vibration and balancing of the HPCI, I'm sorry, of our RCIC, reactor feedwater pumps, as we come up in pressure, as we start up.

We do the same thing with our high pressure coolant in our RCIC testing. That is also done at ready pressure and temp. And we also then do the relief valves. All 13 relief valves, we will cycle those through one cycle, and we will do that ready pressure and temp.

And then the other testing down through here is the EHC testing, and tuning. And we do a lot of tuning, we do testing, we do control valves, and stop valve testing, and then tune it.

And we will do that constantly as we are coming up in power. Because what you are looking for is the best place, sort of a sweet spot, if you want to find one, that the unit tends to take the control

valves going closed, or a stop valve going closed, without doing a perturbation, very much.

You can have, sometimes you can go at a higher power level, and it is less than what it is at lower power level. So right now we do it around 85 percent power on units 2 and 3, and we are looking for that same area, right there, to be where we will test the valves on unit 1, also.

CHAIRMAN SIEBER: Prior to even heating up the unit you will test your main steam isolation valves?

MR. R.G. JONES: Yes, sir.

CHAIRMAN SIEBER: Did you change the valves from the ones that were there, prior to this outage?

MR. R.G. JONES: We will have new -- those valves will be completely rebuilt.

CHAIRMAN SIEBER: But it is the same design?

MR. R.G. JONES: Same design, yes, sir it is.

MR. CROUCH: Same body, different internals.

CHAIRMAN SIEBER: Yes, right. So this is, there is nothing unique about this, from what you have

been doing in the past?

MR. R.G. JONES: No.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: And for unit 1, since we are doing the EPU, which will have the 30 PSI pressure increase, the valves will be set at the new pressure set point.

CHAIRMAN SIEBER: Yes, but that is, you know, three-tenths of a percent?

MR. R.G. JONES: That is right, very small.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: Scram time testing will be done, also, during this plateau prior to getting 55 percent power. And we currently have in our schedule, right now, to do a reactor scram at right around 55 percent power.

Following that we will do a management assessment of the test results, and our plant operations review committee, again, to proceed on. Once we are given the okay to proceed on, we will go to phase 3 testing, that is on page 31.

That power level is from --

MR. LEITCH: I assume, though it is not mentioned, but I assume that at phase 2 you would do a main turbine overspeed test?

MR. R.G. JONES: Yes, sir. We do that when we first tie it on. We will run it about 180 megawatts electrical for about three hours, and then we will actually do an overspeed test on that.

MR. LEITCH: Yes.

MR. R.G. JONES: Yes, sir. Phase 3 testing is 55 percent power, up to 83 percent power. During this time what we are doing here, these tests right here, since you have all the balance of equipment in service, and what we are doing is tuning.

A lot of this right here is tuning, and we are also doing some testing, feed pumps, we will do water level perturbations, up to three inches, water level perturbations, and we are looking for integrated plant response to see how the EAC system, how the feed pump, how the three water, three element control, and how it takes care of that.

And we've also got the variable frequency drive. This is the same variable frequency drives that units 2 and 3 currently have. We will be having, we have those currently on unit 1 also.

And the new HC system is the same EAC system that is on units 2 and 3 that is currently in operation. And all those testing, and tunings, will be done during this plateau between 55 to 83 percent

power.

At this point in time, also, between 55 and 83 percent, we will do a HPCI injection. The reason we do this, is we found out, through operating experience, that the controllers don't necessarily work the same whenever you are going through the test line back to the condensate storage tanks.

And you get a little different operation out of them from that. So we will actually do an injection to the vessel at this point in time, with both HPCI and RCIC, in order to get the tuning set up and make sure that is working fine.

We will also do a recirc pump variable frequency run back test to ensure that they will run back at the different plateaus we have set up. At that point in time, then, we will have another management assessment.

And from there we go into phase 4 testing.

MEMBER DENNING: Now, 83 is the old full power?

MR. R.G. JONES: That is correct.

MEMBER DENNING: I was wondering, here, I mean we expect at this point that the reactor would respond pretty much like it did, originally, or are there reasons why there really are differences?

I mean, as far as looking at the plant performance, and determining are things really happening the way we expect, this is probably the best period? I mean, this is the time when we really get the feeling that yes, there is nothing unexpected?

MR. R.G. JONES: That is right. And we've got a lot of monitoring that we are going to be doing, on the way up, as we look at this. We have a lot of things we look at. And we will show you, on the next page, sort of what they are, when we get into the next plateau.

MEMBER DENNING: Yes.

MR. R.G. JONES: But we are, also, monitoring these things during our normal, as we come up into power.

MEMBER DENNING: Other than with regards to the moving from 55 percent to 83 percent, is there anything that really looks at the transient performance at this point?

Is there any value in dropping down in power and seeing whether it performs the way you would expect as you did a power setback, or is there nothing like that in value?

MR. BARTON: -- on loss of feed, or something like that, is that what you are getting at?

MEMBER DENNING: Yes, that is what I'm getting at.

MR. R.G. JONES: We will base it upon what we get out of our testing that we do on the feed pump. We are not planning on tripping a feed pump, right now, to make sure the others -- but what we do is we set, we have three set up.

Two will be in automatic, and one will be in manual, and we will run it, and we will ramp it back to see how the other two respond to it to make sure that they do.

So the tuning is not just looking at them and making sure that they are sort of doing that, so you ramp one back and the other two, and we will do that through all three of them, we will go through all three of them to make sure that they respond in a way that they should.

MEMBER DENNING: You have --

CHAIRMAN SIEBER: But that is not large transient testing?

MR. R.G. JONES: That is correct, that is not large transient --

MR. BARTON: Turbine trip in power, anything like that here?

MR. R.G. JONES: It is 55 percent.

MR. BARTON: Turbine trip at 55?

MR. R.G. JONES: The one at 55 percent power, the reactor, the reactor SCRAM will give us a turbine trip.

MR. BARTON: Yes, okay.

MEMBER DENNING: Do you have a thermohydraulic model that has been tested against the plant performance and it can reliably predict behavior in this regime, then?

Is that what you are -- when you say you will check it and see if it behaves the way you expect, does that mean that you do prior projections of how you think it will behave with a thermohydraulic model?

Or how do you judge whether it is behaving the way you expect it to behave?

MR. MOLL: Let me answer this. In this testing, this phase 3 testing, and the tuning that RG is talking about, we will collect lots of plant data. The goal of this is to make sure the control system is stable and then basically with damping less than one, as part of the data we collect in that test.

We monitor other parameters, other than just the tuning, but water level power, so on and so forth. The model that we would use to know what we

expect on this testing is going to be the simulator that has been set up to model the plant, which right now is a units 2 and 3 simulator, but the one that is set up for EPU conditions is what -- one of the things we do is we use it, and the operators put it through all its testing as part of their training.

And a large part of what we do with the simulator at Browns Ferry is to make sure the simulator, that really is our best model for how the plant would respond. And it would, basically, what we would be using now in a simulator is making sure it responds.

Based upon the transients we've seen on unit 2 and 3 we feed that information back into the simulator to make sure it accurately responds, as well as there are criteria out there, by the NRC, for how accurate it has to be to the simulator.

MEMBER DENNING: And then how long would you expect to be in this phase 3 period of testing?

MR. R.G. JONES: We have a month, right now, set up for this period of time right here. Our total time, from startup, right now from startup until we get through, it is approximately 70 days, total, period of time when you look at the total time we currently have right now.

CHAIRMAN SIEBER: Maybe just to clarify something. All the testing that you've described, so far, including the tuning testing, is basically steady state testing. You aren't doing big transients, reactor trips, and turbine trips, and things like that.

And so the kind of thermohydraulic modeling that you would do, you could do by hand. I mean, it doesn't take some fancy code to do a steady state calculation as to what things would be.

And even in the neutronics area, those codes are pretty well developed, and so you can look at what your flux distribution is, compared to the power output, and say, yes, this is pretty good.

But as far as the response to a turbine trip, or reactor trip, you know --

MEMBER DENNING: You are saying other than the one at 55 percent?

CHAIRMAN SIEBER: Yes, it is just not in this test program.

MEMBER DENNING: Well, it was at 55 percent.

CHAIRMAN SIEBER: Yes, but that really doesn't tell me too much. For example, if you are at full power, and you obey your tech specs, so that

means that you are at no more than 102 percent power, and you have a plant trip, a lot of things happen in the plant.

Almost everything changes position, and if you have been in the plant when it tripped, the whole plant moves. The piping moves, the hangers and supports moves --

MEMBER DENNING: The lights go out in the plant manager's office, some times.

CHAIRMAN SIEBER: But, in any event, that is when you find supports that were inadequate, snubbers that are bent. And if you don't test at one hundred percent power, you will never get that.

Now, most plants that go into EPU conditions, the argument is always, it is tough on the plant to have a transient like that, we don't want to do it, we aren't going to learn anything.

And what you may learn is that you have a hanger installed backwards, or something like that.

MR. LAMB: We are just going to spend a lot of time on slide 33, when we get there.

CHAIRMAN SIEBER: Well, I'm already there.

(Laughter.)

CHAIRMAN SIEBER: But, in any event, that is where the situation that you are in. Now, the

question always becomes a judgement call as to whether you think you built the plant and designed all the piping and supports, and everything, strong enough to be able to take the jolt of a trip from full power.

And I'm not sure I know the answer to that. I have also seen hilties pulled out of the wall and snubbers bent, too, and other little things that seem to happen.

So go ahead, why don't you move right to slide 33, since we -- 32, all right.

MR. R.G. JONES: Thirty-two, real quick then I will let Bill finish up. I could go to, what I would love to do is take you to 34 and let Bill come back and finish up with 33, when we get through that, then I could be out of here.

So phase 4 testing is our final, it is from 83 percent power to one hundred percent power, which is 3952 megawatts thermal. And our intention right now is to do at 100 megawatt thermal increments.

That will get you somewhere between 2 to 2 and a half to 3 percent power increase at a time. Stop every time, and do a management assessment at each plateau.

So we will go through, what we are looking at are those things that we have under the last

bullet, when you look at those. That is those areas right there we are looking for, and we will be monitoring.

This is the same thing we did, whenever we took the plant on units 2 and 3 up from one hundred percent up to 105 percent power. This is the things that we looked at, right here, to make sure that we are okay, and that everything was going.

So we are pretty comfortable with where this stands, and how this works. It has worked for us before, and we look and see if there is anything we need to add to this, right here, that we would be missing when we look at it.

It is pretty comprehensive on what it looks at. And it says, here is where we are, here is -- and are we where we thought we should be? And if we are not then we stop, back down to the point that we were before, that we were okay at, and then figure out why it changed.

MEMBER DENNING: Do you have predefined error bars on this, that if I'm within such an amount then I think I'm okay, or is it more intuitive than that?

MR. R.G. JONES: We don't happen to define bars on that, currently.

MEMBER DENNING: You don't?

MR. R.G. JONES: No.

MEMBER DENNING: Is there any reason why you wouldn't put some predefined bars on these things, before you go there? I mean, it would give me more comfort if you did, that it wasn't a more seat-of-the--pants kind of assessment of, yes, things look about okay.

MR. MOLL: Some of the areas we are looking at I agree, we can -- we haven't defined what those bars are, and I think we can define what those bars are.

Some of the other testing we will be doing, parameters we are looking at, I'm not sure if we can set a predefined bar. But our intention is, for instance, if we are looking at vibration of large piping we expect to have acceptance criteria at which that vibration has to be below, for us to continue on.

Off-site release rates, yes, we can set numbers on those, RAD levels, chemistry samples, yes, we have limits on those. Some of the other areas, just about all of them, dry well atmosphere cooling we know what our limit is on that, it is driven by tech specs. Yes, we can place bars on that.

Some of these parameters we may not be

able to do that. But where we can, and know what they should be, yes we can, and we will.

CHAIRMAN SIEBER: How much vibration monitoring do you plan to do during a power ascension?

MR. MOLL: Right now we have installed designs out to install large, or vibration monitoring on a large bore piping, primarily main steam recirc inside a dry well and feedwater outside.

There is other components, and other points we will be monitoring via vibration, either by an installed detector, some of it may be visual observation.

We are still in the process of defining those. Most of those points are going to be driven by the, what I will call, the Owners Group Document, that came out on EPU and extended condition, based upon their recommendations, and also GE did a review for the Browns Ferry units 1, 2, and 3.

And identified specific components and other items we need to be monitoring. And they will all basically be in that package, also.

CHAIRMAN SIEBER: Okay. It has been my experience that plants sometimes run better at one hundred percent power than they do at 80 or 90, because of vibration, and the fact that they have some

valves that are throttled, and so forth.

And maybe that is subjective, but it is a good thing for an operator to know where his plant runs the best, so that you can avoid situations where you have turbine resonance, or a valve flutter, or something like that.

MR. R.G. JONES: And that is exactly what we look at on our control valve testing, because you have that knee, or curve.

CHAIRMAN SIEBER: That is right.

MR. R.G. JONES: And if you don't watch out you will get the valve testing done right at that point.

CHAIRMAN SIEBER: And it is going like this.

MR. R.G. JONES: That is right. And that is what we are looking at. So every time we do a two percent, we are going to do valve testing, and we are going to check the control valves, look at them and see how they do.

So we will do at least one valve to see how it does, see how the rest of the system reacts while we are going up in that power.

CHAIRMAN SIEBER: I guess my gesture doesn't show up on the transcript very well. But it

was a shaking gesture. We want to do 33.

(Laughter.)

MR. CROUCH: When we started this morning someone mentioned that they were concerned that we weren't doing any transient testing. As we describe here, as RG goes through the testing, RG and Bob, we will be doing transient testing, we will be putting in step changes to controllers, and stuff like that.

So there is some small transients like that put in. The large scale transient testing is discussed here, is what is referred to in the GE's extended licensing topical report, as a large scale transient testing being an MSIV closure at full power, or turbine control valve for a stop valve closure --

CHAIRMAN SIEBER: MSIV is even more large than a turbine trip.

MR. CROUCH: So I wanted to make sure what we were talking about when we said large scale transient testing. The reason we do not feel that large scale transient testing would be of significant benefit to Browns Ferry is that as we talked about, through the morning, with both Joe's presentation, and RG's, is that all the system functions and actuations will have been designed the same as what they were on units 2 and 3.

And then we will go through and test all the system functions and actuations through the test program. So that if you have a system such as HPCI, that is supposed to operate based upon a low reactor pressure vessel water level, or on a high pressure signal, we will have put in those types of signals, and demonstrated that those systems operate, when the signals are present.

So all the system interactions that occur, resulting from these large scale transient testings, the fact that the system gets the proper signal, and does its proper actuation, would have already been tested as part of the preliminary testing that we have already described.

We've already got through, for units 2 and 3, and installed all these various modifications, like Joe talked about, for visual feedwater controls, digital EHC controls, etcetera, etcetera.

And as part of putting those in, they were tested as part of their modification, and then through the course of the last few years, we have had large part transients occur.

We have closed turbine stop valves, we have had plant trips. We have demonstrated that the response of the systems to these large transients. And

doing so, in all cases, the system controllers responded as expected, all the proper actuations happened, as expected.

When we go over to unit 1, we will have installed the same modifications, done the same, used the same control settings, control programs, those kinds of things. So the operating experience for units 2 and 3 will apply over to unit 1.

CHAIRMAN SIEBER: I agree with you that all of these functional tests determine whether set points are actuated or not actuated in the large transient test that moves the plant around it is not necessary to shut the pressure switches, and flow switches, and pump start and stop.

To me you can demonstrate that in other ways. You have never, at Browns Ferry, run a large transient test, accidentally, or on purpose, above 83 percent of the power that you expect to go to here.

And if you do a large transient test, like a main steam isolation valve closure, or turbine trip, or something like that, the question is, is the plant physically strong enough to withstand that, without damaging -- some damage to the equipment, or surprises to the operator, or something like that.

So sooner or later you are going to do

one. If you run at that power level it is going to happen.

MR. BARTON: It is better to do it early so everybody knows what is going to happen. The operators will feel better about it, too. And by the time you get through with this test program you are going to have a bunch of deficiencies, anyhow.

You may even have to shut down and go fix them, so why not SCRAM for one hundred percent, or turbine trip, go fix them, restart, go online, and everybody is happy.

CHAIRMAN SIEBER: So that is sort of the argument to have large transient tests. But it is not to show that this pump starts, or that pump doesn't start, or these valves change position. You can do that one hundred different ways.

MR. LEITCH: One of the things that I think is interesting is the closure of the MSIVs. There is a prescribed number in the tech specs that says the closing time for the MSIVs, it can't be too fast, it can't be too slow.

MR. CROUCH: That is right, 3 and 5 seconds.

MR. LEITCH: So how do we know that at the new one hundred percent power, that these MSIVs are

going to close within that prescribed time?

MR. CROUCH: They do stroke testing on those.

CHAIRMAN SIEBER: Yes, they are constrained.

MR. LEITCH: But, I mean, with this new higher flow going through them I expect that will impact the stroke time in any way?

MR. MOLL: I don't know, to the best of my recollection the higher flow is not going to affect the stroke time, and the timing and set up we will do on these valves is typical of what we do now for the units.

We don't stroke those valves at one hundred percent power now, and we have guidance, in the procedure, on how to set them up and time them to ensure that 3 to 5 seconds is met, at hot standby, and it would still be met at the full flow conditions.

MR. CROUCH: These valves have enough adjustability on them you could adjust them to be less than three seconds, you could adjust them to be more than five.

CHAIRMAN SIEBER: Right.

MR. CROUCH: Three to five is well within their capability of control.

CHAIRMAN SIEBER: Right.

MR. LEITCH: I'm just not sure that we know that for sure with the higher flow rate going through the valves.

CHAIRMAN SIEBER: I think Graham is right. The flow rate will determine, to some extent, how fast the valve closes.

MR. CROUCH: And realize on this that when Browns Ferry goes to EPU conditions, our steam flow rate, not in terms of mass flow rate, but in terms of velocity, will still be significantly below what other plants are running.

Our steam lines are so large that we won't have the velocities as high as what other plants have. So we are still well within the industry-wide experience on what these valves are capable of doing.

CHAIRMAN SIEBER: Yes, but it is the mass flow rate that makes the difference, right? I have to think about that a little bit, then after I think about it then --

MEMBER BONACA: The issue will come up when we review the power uprate.

CHAIRMAN SIEBER: Yes, maybe we shouldn't be worried about it right now. Okay, why don't we move to slide 34?

MR. R.G. JONES: Just before we leave that point --

CHAIRMAN SIEBER: No, we decided it is an EPU issue, it is not a restart -- well, right now we are doing license renewal.

MR. LEITCH: I thought we were doing a mix of the two today.

MR. CROUCH: The only reason this slide was in here because we recognized that you guys were interested in talking about it. It is really like what you are saying. This is really an EPU question.

MR. LEITCH: I agree. But as far as EPU I guess I would like to know how we can justify saying that the MSIVs close within the tech spec prescribed time, three to five seconds, without dynamically testing those valves.

CHAIRMAN SIEBER: Well, part of that depends on the valve.

MR. LEITCH: Maybe it can't be justified, maybe there is experience that says that that is okay. I just don't know, frankly.

MR. CROUCH: We will take that as an issue and get back with you. Shall we move on to page 34, then?

CHAIRMAN SIEBER: Yes, I think so. In

fact we covered this in August, to some extent. So you can be very brief.

MR. R.G. JONES: Very brief? I can do that. Three unit staffing, one of the numbers that we are going to increase the plant staffing, currently right now, is 126 people, total.

Out of the 126 people, 51 of them are in the operations organization. And that handles the SROs, the reactor operators, and the assistant unit operators. There will be additional individuals that have to be assigned to unit 1.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: We will add five each in training, chemistry, and outages, and three system engineers to the organization. That will increase, out of the 51, that we currently have, there would be 21 senior reactor operator licenses, and 10 reactor operator licenses.

This is the same license. The way our current rotation, now, we currently have a licensed individual on unit 1. Our current rotation, now, for licensing is that we will work an individual on, they work a six group, they work a six week rotation, before they go through a training cycle, and back on.

So they will work through six weeks, work

on the same unit. And when they go to training, if there is any changes in the core mix, in the training, then they do the changes then, so the guys will work together, a little bit, in training.

Then when they come back they rotate to the next unit, and they will stay on the next unit for six weeks. So when unit 1 falls in, they will do the same thing on unit 1, they will work six weeks on unit 1, six weeks on unit 2, six weeks on unit 3, and they will go right down the line in that organization.

MR. BARTON: Is it 8 hour shifts, or are you on 12s, or --

MR. R.G. JONES: It is 12 hour shifts. The only thing that we will change, any way at all, in that organization in that mix, is whenever we get within about the last six months of testing, we have a lot of testing going on, on unit 1, we will freeze, at least one of the operators, not all of them, but one of them, in that group, and rotate the other guys through, so you will have some consistency in what the guys do.

We do that with the SROs also. And we have done it before, and that worked very well for us, in going through that. The simulator, I think we showed you the two simulators.

The new one, it will look like unit 3, and it will match the units 2 and 3 configuration, and we will take the old one, prior to unit 1 startup, and we will be able to take the individuals and go through it, and we will uprate it, so it will look like the uprated plant, and they will be able to look at those, also.

CHAIRMAN SIEBER: Okay.

MR. R.G. JONES: I think another question you had was on the EPGs. Our emergency procedures are, when we startup unit 1, we will be under REV 2. And we use an EPG SAG REV-2, is what we will be under on that.

Each one of those are plant specific, or unit specific, when you look at our EPGs right now. So unit 2's is a little different than what unit 3's is, and it is really based upon, again we talked earlier about the RHR, and the unit 2's ability to cross-tie, back and forth.

That makes some of the set points a little different, because you have a little bit more flexibility in those that you wouldn't have if you are on unit 1 or unit 3, on the outside unit. So unit 3 is going to look a lot like what unit 1 does.

But as far as the format, and everything,

it will be the same. So when an operator is looking at it, and he has the EOIs laid out in front of him, going down through them, the only thing that will trigger him to do a response, is where the set point is, and it could be different on unit 1 than it is on unit 2, and unit 3, based on where we are.

But they don't go to that, they go through the procedure part of it, so they follow that right down through it.

MEMBER BONACA: You were saying something before, you are going to mix the crews? I mean, that is what I thought.

CHAIRMAN SIEBER: Rotate them.

MR. R.G. JONES: And let me tell you one thing, we have a large training class, we have large training classes currently in progress, right now, in order to meet the numbers that we are going to need to go to this right here.

We've got the SRO candidates in process now. We have a lot of assistant unit operators. And we are bringing them back, we do not put all the new guys together on one crew. They are separated throughout the crew.

So that you have experienced people with the new guys at the same time. And we make sure, when

that goes through, that that happens, also.

CHAIRMAN SIEBER: Is that it?

MR. R.G. JONES: That is it.

CHAIRMAN SIEBER: Okay.

MR. CROUCH: So RG has gone through and talked to us about the thought process, how he is going to make sure everything gets done, before we turn it over to the plant.

As we go through the testing, these functional tests, like he talked about, and make sure that the systems really will pump water around, that they will do every filtering, processing, whatever they are supposed to do.

Then we have the restart test program, to make sure that the safety related functions will function as designed, and as required by our licensing basis.

We will be testing all the way from open vessel, zero percent, all the way up to one hundred percent power. And we are prepared to operate three units, as he talked about. We are adding staffing as required, we are adding simulators as required, we are doing the training as required.

So we, as a site, will be ready to operate all three units concurrently.

CHAIRMAN SIEBER: So not only is it required to filter water, but it is supposed to get hot too, right?

MR. CROUCH: Why don't we take a break for a few moments?

CHAIRMAN SIEBER: Okay, I think that will be good.

MR. BARTON: Those guys run a meeting pretty good.

CHAIRMAN SIEBER: Yes, they do. See what happens when you -- Why don't we come back at 3 o'clock?

(Whereupon, the above-entitled matter went off the record at 2:45 p.m. and went back on the record at 3:00 p.m.)

CHAIRMAN SIEBER: It is about time for us to resume.

MR. CROUCH: The next section we are going to talk about is the actual license renewal application. We are going to have Rich DeLong, who is our Browns Ferry site engineering manager, talk about that to us.

During this he is going to talk about the actual license renewal application that was made at the current licensed thermal power, as we've talked

about, it is a progression type series.

So what he is going to talk about is at the current licensed thermal power. He is going to talk about the application, the aging management programs that go along with it. Due to the fact that unit 1 is being restarted, and brought up to the same licensing basis as units 2 and 3, there are some unit 1 specifics that he is going to talk about there, in terms of the effect of monitoring that we are doing, among other things, to bring the units together.

And then, finally, the issue that exists of why is it appropriate to apply for a license renewal for a unit that only operated for ten years. So with that I will turn it over to Rich.

MR. DELONG: Good afternoon. The license renewal application for units 1, 2, and 3, was submitted in December 31st, 2003.

The license renewal application for Browns Ferry is done, assuming current licensed thermal power. It is consistent with the generic aging lessons learned, or what is known as GALL.

And, also, our license renewal application results in the existence of 39 aging management programs.

MR. CROUCH: Let me interject one thing,

and correct one thing that I got told earlier. You asked, earlier, were we using GALL REV-0, REV-1, or whatever. And I told you REV-1.

CHAIRMAN SIEBER: Right.

MR. CROUCH: We have now confirmed that it is REV-0, and Ken will speak to this.

MR. BRUNE: Yes, it is REV-0, what was issued around 2001. We misspoke earlier.

MEMBER BONACA: Although you have addressed the ISGs?

MR. BRUNE: Yes, we have addressed the ISGs, that should be in the SER, also.

MEMBER BONACA: In the application, yes.

MR. BRUNE: In the application.

MR. LEITCH: Just one question I had, Rich, about this 1, 2, and 3. I thought I heard, earlier, that 2 and 3 were first considered, and then 1 was added later. But that was all done prior to the submittal, is that correct?

MR. BRUNE: Let me speak to that a little bit.

MR. LEITCH: Sure.

MR. BRUNE: Yes, units, we initially started the license renewal applications for units 2 and 3 only, and then unit 1 was, as we decided to

restart the plant, it was added on to the license renewal application, and then in development of the application we looked at it, at all times, with respect to a three unit application, after, you know, once they put unit 1 in.

We tried to get all the material and environments, and everything, as unit 1 would be at its final configuration.

MR. LEITCH: But my question, basically, is was it submitted to the NRC as just units 2 and 3?

MR. BRUNE: No, it was submitted as a three unit application.

MR. LEITCH: Okay. So the earlier thinking was all prior to the submittal?

MR. BRUNE: Yes, it was.

MR. LEITCH: Okay, thank you.

MR. DELONG: Going on to slide 36, again the application was submitted in December of 2003. We received a total of 230 requests for additional information, of which 30 were unit 1 specific.

The draft SER, with open items, was issued on August 9th of this year. And the two open items are related to, firstly, the dry well shell corrosion. And we are in the process of evaluating what will be required to do additional inspections on the dry well

shell.

The second is stress relaxation of core plate hold-down bolting. We submitted a response to that open item, and there are some additional questions that the Staff has, and we are preparing our responses to those additional questions.

Slide 37

MR. BARTON: Dry well corrosion question, the light bulb portion or what? Because you inspected above the floor, at the floor interface level? What is going on in the sand bed area?

MR. DELONG: It is also, I guess, in our case we do not have an issue with, for instance, felt liners, or felt overlays, or those kinds of things that some utilities have had difficulty with.

But we do have the, I guess, a similar design in terms of sand bed. As I mentioned before, on slide 37, we have 39 aging management programs, a total of 38 are common to all three units, and one of which is a unit 1 specific program, we have alluded to it and mentioned it a few times today, we will talk more about it here in a few slides.

Twelve of our existing aging management programs require no enhancements, since in their existing state they were consistent with GALL. Ten of

our existing aging management programs required enhancement for all units in order to make them comply with GALL.

Eleven of our existing aging management programs were revised to include unit 1. They were already consistent with the generic aging lessons learned, but because of when those requirements came about, in the course of time, unit 1 was shut down during that period, and had not been included in those programs, and needed to be added.

And there are six new aging management programs. On slide 38 is a listing of those programs that require no enhancement. Slide 39 is a listing of programs that required enhancement to comply with GALL.

MR. BRUNE: Rich, let me -- just going over this list again, I think we may have one correction on it. The vessel internals program --

MR. BARTON: Which page are you on?

MR. BRUNE: On page 39. You might want to look at the vessel internals program. The only enhancements that we put on that was for unit 1. So I think we may need to move to the next slide.

MR. DELONG: On the GALL compliance list? I see what you are saying.

MEMBER BONACA: This is the enhancement to bring it in line with the --

MR. DELONG: We already complied. What he is saying is that that one actually belongs on the next slide, which is adding unit 1 to our existing vessel internals program, which is fully compliant.

CHAIRMAN SIEBER: What did you do to the masonry wall program? You know, that has been an issue that has been around for a long time.

MR. BRUNE: Let me address that. The biggest part is we made sure we updated our procedures to include everything. Give me a second and I will tell you.

CHAIRMAN SIEBER: Okay.

(Pause.)

MR. BRUNE: The enhancement is -- we are going to be enhancing procedures for the maintenance rule to identify all structures and components that are in scope for license renewal. It is not that we are really -- we are just going to make sure all the procedures cover everything properly.

CHAIRMAN SIEBER: That doesn't sound like it is related to masonry walls.

MR. BRUNE: I'm sorry, let me read again. Essentially procedures will be revised so that

structures with masonry walls, within a scope of license renewal, are clearly identified in the qualification requirements for personnel who perform masonry wall walkdowns, within the scope of license renewal, is clarified.

So it is personnel requirements, and to make sure that all of the procedures are in place.

MR. CROUCH: So it doesn't sound like there are any real technical changes. What we were doing to masonry wall was simply a matter of making sure that all the masonry walls were included, and that all the requirements for people performing those inspections are clearly delineated.

CHAIRMAN SIEBER: And to me that represents no change, because you are already supposed to do that. That goes way back to the 1980s.

MR. BRUNE: This goes back to, probably, we may have been better off not having it as an enhancement, but that is the way the application was submitted.

CHAIRMAN SIEBER: Okay, thanks.

MR. DELONG: On slide 40, these are the existing aging management programs that require revision to incorporate unit 1 in their scope, where it was not previously recorded, or required.

CHAIRMAN SIEBER: Okay.

MR. DELONG: On slide 41, these are the new aging management programs created for all three units. And the bottom there, of the unit 1 only program will have a follow-on slide, to talk more specifically about the periodic inspection program for unit 1.

MEMBER BONACA: Just one comment we made this morning. We got into the one time inspection program, at least in the SER, but also I believe in the application there is a mention of a one time inspection prior to startup.

And to the degree to which we differentiate it is good to maintain of one inspection only associated with license renewal. Because it confuses.

MR. DELONG: Yes, there is the one time inspections that are, that is the program that all applicants for license renewal are dealing with.

MEMBER BONACA: That is the one in GALL, that is right.

MR. DELONG: Then there is the unit 1 periodic inspection program that includes a baseline inspection prior to startup. You are saying there are some issues where --

MEMBER BONACA: No, there are some locations, specially in the SER, where the actual inspections prior to startup are called one time inspections. And that is confusing.

Because if it is interrelated to license renewal, it should be separated. It simply is good to keep them separate, otherwise there is the confusion of what the purpose of the inspection is.

For example, you may have an inspection that you do on a piece of piping to determine that your lay-up was acceptable. And, you know, if you do it just for the purpose, and not for license renewal, you should not call it a one time inspection, because this is just a question of nomenclature for the purpose of clarity in the SER.

MR. KUO: Dr. Bonaca, I think we understand your comment, we are going to go back to the SER to look for --

MEMBER BONACA: Yes, I made it generally now, because I know that you understood that, and I want to make sure -- I think the application also had some use of words like that.

MR. KUO: We will clarify it.

MEMBER BONACA: Okay.

MR. DELONG: That was something that we

recognized, that we confused the terms occasionally. We used one, should we use the other one?

MEMBER BONACA: Yes, and what happened is that when I read one time inspection for startup verification, I'm thinking, wait a minute, are they doing the license renewal inspection now, so what are they doing later? So that was the confusion.

MR. DELONG: With respect to the unit 1 periodic inspection program, which is the program we said that is unique, and for unit 1 only, this program is directed at making sure, as we proceed, or approach the renewal period, and then proceed into the renewal period, that we have a way of understanding, or in fact refuting, whether there is any effect on that unit regarding our 20 year ideal period, which would otherwise be understood and detected through the other aging management programs.

MEMBER BONACA: So you are looking at aging degradation rate, you want to measure that?

MR. DELONG: That is right.

MEMBER BONACA: I mean, you want to know if there is a rate of degradation that is beyond what you expected?

MR. DELONG: That is, somehow, related to this extended idle period for the systems that --

MEMBER BONACA: Now, the bullet there says that will be performed prior to plant would be started, prior to the period.

MR. DELONG: Yes, there are really a couple of phases here. One is, of course, a set of baseline inspections which is occurring as we go through this recovery period for the unit.

Those will be followed by a first inspection. The first inspection is done prior to startup, or really, prior to the renewal period. Prior to the period of extended operation.

MEMBER BONACA: Okay, so --

MR. DELONG: Not necessarily prior to startup, but prior to the period of extended operation. And then that sets the stage for determining what the frequency of those inspections ought to be, as we proceed into the renewal period.

MEMBER BONACA: So I would expect to see at least one verification during the renewal period? If you do the base lining, say two years before you get into renewal, okay, then you would want to verify the rate of degradation, if there is any, and so you, say, we will do another inspection in ten years, or five years, whatever you decide to propose.

After that then you make a determination.

If there is no degradation taking place, you have two points. You can make a case for not performing additional inspection, but you have done one during the period of extended operation.

If you have degradation occurring then you would make it more, I mean, that is the way I view a periodic inspection.

MR. DELONG: I think that is correct. Enough data must be compiled, depending on what type of inspection program, to make a judgement about, number one, is degradation occurring, how fast is it occurring, and on what frequency do I need to make follow-on inspections.

It is conceivable that we may have cases where we don't see any degradation, and make choices to suspend inspections in some areas.

MEMBER BONACA: That is the periodic inspection only?

MR. DELONG: No, you can't create a line with one dot.

MEMBER BONACA: Well, the point I'm trying to make, however, we have discussed this for other applications, the importance of having the baseline happening close enough to operation, two years before, three years before, not immediately at startup.

Because otherwise you are not measuring the effect of operation at full power, you are measuring the effectiveness of the lay-up.

MR. BRUNE: Let me address it a little bit. The inspections we are going to do at startup, I guess we are now referring as restart inspections. And those will be, I guess, you will call them baselines. But where we will start from our initial set of data.

And then we will do one more set, as you pointed out. Rich said prior to the period of extended operation we will do another set of inspections. And then I guess, you know, we are looking at doing another set after we get into the extended period of operation to determine what frequency, to asses where we are at.

MEMBER BONACA: Well, that is fine, in fact.

MR. BRUNE: And that is going to be, some of the details we will be working out with the Staff on better defining what one time inspections are, what restart inspections are, and what periodic inspection is.

MEMBER BONACA: That was a good clarification. Because, I mean, when I read the SER

there is a good discussion there, that I understand that you have been reviewing with the Staff, where the distinction is made between an inspection that you do at startup that, really, asses impact of the lay-up, if you have any concerns with that, versus the ones you make to monitor the rate of degradation, due to aging at full power.

So you want to have, at least, a couple four years between restart and the time you make that inspection, there, to give it time to see what the effects of operation at full power will be.

I think we have an understanding of --

CHAIRMAN SIEBER: Okay.

MR. DELONG: On slide 42, which is really a lot of what we just talked about, and --

MEMBER BONACA: -- would be initiated prior to operation?

MR. DELONG: Right. I'm sorry, I missed the question.

MEMBER BONACA: On the third bullet it says, the periodic inspections will be performed prior to the period of extended operation.

MR. DELONG: You are talking about the first set.

MEMBER BONACA: Will be started.

CHAIRMAN SIEBER: Initiated.

MR. DELONG: Initiated, yes. It would have been a better thing to say the first set, or would be initiated, yes.

Slide 43, Appendix F, in the application, is related to the unit 1 differences. This is back to the issue related to the fact that at the time of application the licensing basis for unit 1 was physically different than the licensing basis for units 2 and 3.

This appendix, it delineates what those differences are in licensing basis. Again, our intent to start these units up, and run these units operationally identical. That doesn't mean they are physically identical, but they are operationally identical.

To meet this principle unit 1 current licensing basis at restart has to be the same as it is for the current licensing basis for units 2 and 3. And these differences that we have currently, and that we had at the time of application, will be eliminated prior to unit 1 restart, through some of the tech spec changes we have already, and licensing actions that we have already discussed, and modifications must accompany those, that are modification related.

MR. CROUCH: And recognize, too, that when we say that the unit 1 licensing basis will be same as for units 2 and 3, like we talked about earlier, unit 2 is moving towards EPU at virtually the same time as unit 1.

The unit 2 EPU outage will occur just shortly after unit 1 restart. So at unit 1 restart we will be slightly ahead by a period of just weeks, or so. But at the end of that short period we will have the same licensing basis as unit 2, and then unit 3 for the next outage, when it occurs.

We are considering that to be the same, since we are all moving at the same spot, as we talked about, with the outage modification sequence.

MR. KUO: Excuse me, if I may ask a question? The current licensing basis that you are talking about, right now, is that at the power level one hundred percent, or one hundred and twenty percent?

Are we mixing the uprate with license renewal now?

MR. CROUCH: The license renewal application addresses the current license power for unit 1, which is the 3291 megawatts. Obviously when we restart we will be at the 3952 megawatts.

And when we get to restart we will actually be at the same 3952 megawatts that unit 2 will be at, just weeks later.

MR. DELONG: However, appendix F is intended to show the differences at the time of application and not related to differences that will occur later in time, when we are working through extended power uprate implementation.

MR. CROUCH: Said another way, if we had restarted unit 1 at the very same power level as what units 2 and 3 are at right now, the items that are in appendix F would have had to have been resolved to make the licensing basis the same.

These do not have anything to do with the changes due to EPU.

MR. DELONG: Slide 44, I think that is what we are on, shows what those differences are, that are reflected in appendix F of the application.

MR. CROUCH: Primarily these are for modifications. There are a couple of program type things in there, like we have to implement maintenance rule for unit 1, but the rest of the stuff up there is BWRVIP.

But the rest of this is, primarily, just modifications that have to be made to make the plants

operationally the same. They are all within our scope, they were within our scope even before license renewal was started.

And with that I will turn it over to Joe McCarthy, to talk a little bit about operating expense.

MR. MCCARTHY: You've asked us to address the Statements of Consideration and the license renewal rule and operating experience.

In the Rule it says that an Applicant can't submit a request for license renewal until earlier than 20 years before the expiration of the current operating license.

Unit 1's operating license expires in 2013 and, therefore, we met the specific requirements of the Rule. From the Statement of Consideration, the basis for the 20 years, was to ensure a substantial amount of operating experience had been accumulated before the application was submitted, such that specific concerns regarding aging would be disclosed.

However, we need to note that operating experience is not limited to what the license renewal applicant has, it is based on the industry experience. And that was also discussed in the Statement of Consideration.

From the 1991 to the 1995, and to today, there has been a significant amount of regulatory history that demonstrates that 20 years of plant specific operating experience has not been required by the NRC.

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MEMBER BONACA: Wait, wait a minute. I know that it is getting late, but first of all, clearly the 20 years is something we do not have any particular hangup on. I mean, we have already a couple of cases where there were 19 years of operation and we have accepted it, that is not the issue.

Your definition of operating experience, however, has been only generic experience. I don't think that is the way that we have interpreted that. I mean, clearly the Statement of Consideration speaks of 20 years experience, or thereabouts, because at times units operate differently, historically, in part because of different environmental conditions, from unit 1, 2, or 3.

Or because of different materials in certain systems, between the three units. Or because maybe lay-up conditions, or whatever. Putting aside those other things, the outcome would be different.

In fact we have had with you a lot of

discussion on the issue of lay-up, and how you compensate for that, and the replacement pipes, and all those kinds of things have to do with compensating for the fact that you do not have operating experience specific to unit 1.

You don't have the same argumentation about lay-up conditions for unit 3. Why? Because you have enough operating experience to say that is behind us, we don't have to think about lay-up.

So it seems to me that, you know, that is not as clear-cut as you presented it.

MR. DELONG: I wasn't trying to present it as clear-cut. What I was trying to do is define what has happened in the Statement of Consideration, the five exemptions that the NRC has requested, and approved, and then go from there and try and discuss Browns Ferry, specifically, on the next slide.

MEMBER BONACA: Okay.

MR. DELONG: There has been five scheduled exemptions allowed by the NRC to date. Specifically Catawba, St. Lucy, Beaver Valley, Nine Mile, and Millstone III.

For Nine Mile 1 and 2, for example, the exemption was allowed based on common operation and maintenance, use of industry operating experience, and

the environment, even though they are two different BWR designs, a BWR2 and a BWR4 at Nine Mile.

During the public comment period the NRC specifically asked for comment on 20 years. DOE noted that in general aging effects are apparent after only a few years of operation and they further said that they didn't foresee any environmental or safety effects that would be allowed by renewing a license less than 20 years.

MEMBER BONACA: But in fact in a few had come with a license renewal application say, three or four years after restart. I don't think we would raise this issue.

MR. DELONG: Three or four years after restart we would be outside the window to apply. The statements require --

MEMBER BONACA: No, but I'm only saying --

MR. DELONG: -- less than 20, or less than 5.

MEMBER BONACA: I understand. I'm only saying on an issue of performance, okay? I don't think you need 20 years. I agree with DOE's perspective, that you do not need that long, particularly because you have the other units, too, that give you information.

So it would have been a different story. Right now this plant is not even complete yet, that is why the issue came up. But, anyway --

MR. DELONG: Well, I think also two considerations need to be aired here. I think the first one is related to the existing systems that are not replaced, and the ability for us to use unit 2, particularly unit 2 experience in aging, since it has run longest, to understand how the systems in unit 1, that have not yet been, or are not replaced, and will not be replaced, will perform.

And I think there is a strong correlation between our experience in unit 2 and, certainly, in unit 3 for those systems that experienced a ten year lay-up.

The combination of that experience gives us reasonable assurance that we will understand how unit 1 will age for those systems, and how well they will do over time as we proceed through the renewal period.

Now, let's talk, for a minute, about the replaced systems, for a moment. These are new piping systems, new components, etcetera. I see those aligned, those align very well with our ability to run an originally licensed plant, if you will, a newly

licensed plant.

And we will have experience with those systems operationally that we will deal with. You know, we talked about that. At Browns Ferry there will be times, there will be things that we experience with new components.

But from a piping system point of view, of materials point of view, those kinds of things, I see it no differently than, if you will, licensing a new plant, in those cases.

MR. CROUCH: When we did those replacements we used the same materials as what was in units 2 and 3. So that the experience that we have had in units 2 and 3 will, should be directly applicable, material-wise, over into unit 1.

MEMBER BONACA: Well, I have no problems with the new systems. You know, you have -- I raised this issue this morning because in the application, in the SER, there is nowhere that is being addressed this issue, okay?

MR. DELONG: I understand.

MEMBER BONACA: And yet through all the SER there are many considerations of all these issues here. For example, we are going to do this, we are going to inspect the systems, which really are

complimenting what we don't know about this plant from operating experience.

For example, the periodic testing is done, exactly, because we don't know exactly what is going to happen because of the lay-up. So we have periodic inspection that would allow to gather information and complement, or supplement what you get from operating experience.

So the point I made is somewhere there has to be an explanation of why the position taken is acceptable. And I think it is a question of documentation, probably, it is a question of pulling it together.

You have a number of arguments here, we discussed this morning. And I think it is important, from a perspective of public acceptance, you know, there has to be a document that is scrutable.

MR. DELONG: I appreciate that.

MR. CROUCH: And we will work with the Staff to get that information into the SER.

MEMBER BONACA: And a number of these issues, absolutely, I recognized them this morning as being important and useful.

MR. DELONG: I think the final slide summarizes some of your issues. The unit 3 was shut

down for ten years. We had extensive lay-up experience which we believe is directly applicable to unit 1.

We have no, when we started up unit 3 in 1995, and to date we have no post lay-up aging effects from that ten year period. We also used some of the lay-up experience, directly, to determine replacements that we should do on unit 1 that made prudent sense.

And we found, indeed, the degradation was there, and that was like the RHR service water pumps, RHR service water piping in the reactor building, that we mentioned, and some additional small bore piping.

And then there is the consideration that our unit 1 design, or configuration, or operating procedures, the technical specifications, and the one FSAR are all applicable to all units.

Appendix F ensures that the licensing basis will be the same for all units at restart. And we also have the periodic inspection program that we discussed at some length, where we get our baseline as a subset of restart, and prior to the period of extended operation we would do our first series of inspections, and determine when the next one should be done.

Do you have any questions on this section?

(No response.)

MR. DELONG: So here we talk about the fact that our license renewal application was prepared, submitted, consistent with the GALL, the aging management programs, and has been prepared consistent with the GALL, with the exemptions as we noted, there are a few places where we are actually using later documents than what the GALL suggests.

Those aging management programs have been prepared, they are all existing documents now. As a matter of fact, during this week, the region 2 is at our site doing an oversight inspection of those aging management programs.

The unit 1 uniqueness aspects have been addressed through both the fact that we have this license renewal application, that calls it out specifically. We have our unit 1 inspections that will be going on, that will be specific because of the fact that unit 1 has been shut down.

And we are addressing the differences between units as part of our recovery process. We talked about we think the operating experience we have from units 2 and 3, both true operations, as well as shutdown followed by operation, is directly applicable to unit 1.

And we will work with the Staff to make sure that that is properly documented in the SER. So overall, with the program documented the way it is, and with all the work that we are doing on unit 1, the condition of unit 1, and the condition of units 2 and 3, the license renewal program meets the requirements of 54.17.

So we think it is a sound program. Any further questions on the license renewal application, per se?

MEMBER BONACA: As I said, I think that some of these elements can be pooled together, as it is done in this slide, that we haven't seen before.

CHAIRMAN SIEBER: Okay, move on to the --

MR. CROUCH: The last part of our presentation, today, as we've talked about the meeting here, the reason we are meeting here is to actually talk about license renewal.

But when this subject comes up, the issue of extended power uprate has a way of figuring into this because, obviously, EPU does have some effect on the ability of the systems, the aging of the systems.

And so what we want to do today is to talk about what that impact is on license renewal, but recognize the fact that when we discuss license

renewal, and ACRS hopefully puts together their recommendation, or their approval for license renewal, you are really only approving license renewal at that time.

The official approval of EPU, and its direct effects on license renewal, actually occurs as part of the EPU application, which will be early next year.

So we want to make sure, we touched it now, since you were comfortable with it, and you understood how we see the impact of EPU on license renewal.

CHAIRMAN SIEBER: Let me address that. I think you can rest assured that we will address license renewal and we will hold in abeyance EPU questions until it is time to address those.

MR. COUCH: Right.

CHAIRMAN SIEBER: Okay.

MR. COUCH: That is my understanding.

MEMBER BONACA: I think that the importance of looking at EPU, in the context of license renewal, has to do with operating experience. You can't ask the ACRS, you know, we have a task, and a mission, which is a little different than the one on the NRC.

We are an independent committee, and we follow the rules, but we raise questions. And the day in which you will march into license renewal for this plant, this plant will be operating at 20 percent power higher than what is the evaluation done here.

So we are looking at all these aspects. Somewhere they have to be addressed. Now, again, we discussed the report that you are supposed to do prior to entering license renewal, the EPU, and that may be sufficient.

But from a perspective of thinking about operating experience, you have to think about this plant, that operated for ten years, sat down for 22 in lay-up, restarted, went up, and then it goes up 20 percent above the power level, it runs for four years, or five, before you get into the license renewal period.

That is the operating history that this plant will have by the time it marches into license renewal. So we are thinking about it that way. Now then you can ask us to box it in different licensing actions.

But I think we want to think about the issue and the safety issues associated with this operating history. So -- and that is the way that I

think most of the ACRS will think.

MR. COUCH: I understand.

CHAIRMAN SIEBER: Okay.

MR. COUCH: So our EPU submittal was made consistent with GE's licensing topical reports, the ELTR1 and ELTR2 that gives the overall process for how to do a license uprate, anywhere from your original one hundred percent power, up to as much as one hundred and twenty percent.

We utilized this for both unit 1 and units 2 and 3. We also submitted the information requested in the review standard for power uprates, dated December 2003. And that is, basically, a comparison of the various criteria related to EPUs, and show how you meet those criteria.

We've also included, as I mentioned this morning, the fact that when we did our EPU application, we went out and found the RAIs from all the other plants that have already made EPU applications, whether approved or not approved, included that information on the RAIs into our submittal.

One difference between the two plants is that unit 1 will be started up with GE-14 fuel. Units 2 and 3 is in the process of transitioning to the

Framatone A-10 fuel.

Page 49. This is a side by side type of comparison of unit 1 versus units 2 and 3, starting out the original thermal power, you can see was the very same for all three units.

The current thermal power for unit 1 is still the same as it was, because we have not done any power uprates. But we have uprated units 2 and 3 by five percent. We are going to request a thermal power of 3952, which represents a 20 percent increase over the original licensed thermal power, which will be approximately 15 percent increase for units 2 and 3 right now.

When we did the power uprate for units 2 and 3, the first five percent, we increased the reactor pressure 30 PSI. Even though GE has now decided that you do not have to raise the pressure in order to be able to get to EPU conditions, we are going to go ahead on unit 1 and raise the pressure up, so that we have the same operating condition on unit 1, as what we have on units 2 and 3.

Once again going back to the operationally similar, make sure that the operators see the same thing day in and day out, from one unit to the next.

Page 50. And this is basically the same

slide as what we showed you when you were at our site. There has been several modifications made to the plant in order to achieve the extended power uprate application.

I'm going to start with the reactor over on the red. The reactor itself did not require any modifications, except the recirc pump was required to be rerated. While you are not really pumping much additionally flow around, it requires some additional horse power due to the added pressure drop through the core.

So we had to uprate the motor on the recirc pump. The steam drier modifications that are coming out of the issues that --

MR. BARTON: Was that any change to those motors, or was that just penciled -- how did you rewrite them?

MR. DELONG: It was just a calculational rewrite.

MEMBER BONACA: Calculational rewrite?

MR. DELONG: That is correct.

CHAIRMAN SIEBER: The motor will run a little hotter now.

MR. COUCH: The steam drier modifications coming out of the issues, we're actively pursuing

that. And participating in various activities with GE, those modifications have not been completely finalized yet, but we will respond to the overall issue of the steam drier degradation, as it has been occurring.

Moving on down the steam lines, the main steam relief valves, that aren't shown here, they will be reset, and the set point increased 30 PSI, to accommodate the increased pressure.

High pressure turbine, we are replacing the high pressure turbine rotors to get the extra steam flow through the high pressure turbine. Next down the line is a moisture separators.

We are going in and upgrading the moisture separator internals to go into the new double-hooked veins, internals. The original moisture separators had about an 80 to 85 percent efficiency. When we go to the new more separator internals, it will go up to around 95 percent efficiency, that will help eliminate a lot of the moisture going down the steam lines and, hence, going to the turbine.

As a result of doing that not only will we get increased power because we are doing a power uprate, we will also pick up about seven megawatts because of just getting the extra moisture out of the

low pressure turbines.

The low pressure turbines, we will be replacing the rotors in them. That is not being done due to EPU, but it is just a big mod that is going on, that is compatible with the EPU.

The main generator has been rewound. We have replaced the fans on the ISO-phased buss duct cooling. Originally there is, or currently there is a single fan. We will be aging to dual fans.

We have upped the flow rate enough so that we make sure that there is adequate flow rate through the ducts. We have replaced the main bank and spare transformers out in the yard.

And there is also a substantial amount of substation upgrades off the site. Following the condensate path coming out of the condenser, the condensate pump itself, we are replacing the pump impeller, and the pump motor.

When you guys were there we took you down there and showed you the pumps. These are the pumps that are down imbedded in the concrete, and it was not feasible to replace those pump bowls. But we are replacing the impellers and the motors on them.

The next thing down the line will be the condensate demineralizers. In order to pass adequate

flow, and maintain adequate filtering of the water going back to the reactor, we are adding a tenth demin, in all the associated pumps and controls, and everything that is required to run those.

The condensate booster pump, in this case, we are replacing the entire pump, motor, everything. The next thing that we are doing major work on is the reactor feed pump turbine. And the pump in the turbine itself, we are replacing the pump and the turbine.

Now, when we replace the feed pump, and the condensate booster pump, we increased the size on them, enough, that we will be able to run with less pumps, if we have to, than what we currently do.

Right now you essentially have to run with three condensate pumps, three booster pumps, and three feed pumps. If you lose any one of the three, you've got to take the power down in order to keep up with the power.

With these new higher flow rate pumps, we will be able to run in a configuration with two feed pumps, two booster pumps, and three condensate pumps. So it provided extra margin to the plant, extra flexibility to accommodate plant transients.

Then on down to the feedwater heaters.

The number three feedwater heaters we're making substantial modifications to them. They are having steam impingement plates put in.

The steam duct going into the heaters is being moved, physically, down from the top to the middle, to make it a better thermal location for the heaters.

So lots of things going on in the plant that are all geared towards accommodating the steam flow, but also adding margin in, to get the power, accommodating the steam flow to get the power out, and adding margin to get the plant to run better.

And as we talked about earlier all these mods, as well as a lot of other mods that I haven't talked about, are included on the last four pages of your handout, for the list of modifications.

Turning over to page 51, if you start thinking about what does power uprate really do to your plant, what I try to show here was that when I go to the power uprate, where I'm going to raise the flow rates of the plant, and I'm going to raise the pressure, I tried to demonstrate what the impact on each system is.

The main steam system, obviously, you will see a slightly higher steam flow, about 15 percent for

units 2 and 3, or 20 percent for unit 1. There is a slight increase in the moisture content, also.

You go on down the system, the extraction steam has a steam flow increased moisture content. And you can read the list down through here. The reason for putting together this slide is the fact that when you look at all of these effects, these effects primarily occur in the area of flow accelerated corrosion.

The higher steam flows, the higher moisture contents would tend to increase the rate of flow accelerated corrosion. That is well within the guidelines, or the purview of our FAC program.

So the impact of going to the increased pressures, temperatures, flows, etcetera, are monitored by existing plant programs. So that if we are seeing any degradation due to the extended power uprate, on plant life, you would see it as part of this FAC program.

CHAIRMAN SIEBER: It is not clear, to me, though that the rate of the occurrence of FAC is linear with these increases in flow and moisture. Now, you may, up to a certain flow rate, you may get very limited amount of FAC, and then as you increase flow of moisture, beyond a certain point, it may

accelerate more than the linear projection might be.

So you are going to have to pay attention to the measurements that you get, and recognize that it may not be linear.

MR. COUCH: Right. We, when we go out for each outage, we go out and do the grading and the UT effective measurements. We take the information back, run it through our FAC program, which includes the FAC manager, and checkboards, and all those things.

And we trend all this so we can see what the trends are for the degradations. It is all a part of our standard program.

CHAIRMAN SIEBER: The two points don't describe a curve.

MR. COUCH: That is right. But as long as the two points, if you extrapolate them, and it is nowhere near failure, then you would continue to operate. And once you get the third point you can see, is it a parabler, or is it a straight line.

CHAIRMAN SIEBER: Right, okay.

MR. COUCH: Now, as we go through our FAC program, we project out each cycle, is there enough margin in the plants to operate not one cycle, but two cycles.

And so if we have a situation where it

looks like that the rate is rather high, then we would have to stop and address that before we went on with that particular physical location.

CHAIRMAN SIEBER: Okay.

MR. COUCH: So kind of in summary, on page 52, the impact of the EPU on the aging of the plant is controlled, and monitored, by the existing aging management programs, such as the FAC program.

The EPU submittal has been accepted by the NRC Staff, and we target an approval date of spring 2007. So even though you have to consider the effects of EPU, as you are thinking about license renewal, that is our official forum for where we would address the impact of EPU, as part of that EPU submittal.

And the ACRS review of the EPU has got to consider the review, the license renewal, you have to consider the impact of EPU, and that is what we are doing here today.

So that is the whole reason for presenting this.

CHAIRMAN SIEBER: That will require some discipline on our part, to consider the effects, and not consider the whole EPU. So we will endeavor to do that.

MEMBER BONACA: I mean, the -- for Dresner

and Quad Cities, we had the EPU before the license renewal.

CHAIRMAN SIEBER: Right.

MEMBER BONACA: So the GALL report documents a requirement for the licensee before he walks into license renewal to perform an evaluation of what impact, if any, there is on the EPU.

I don't think that that is relevant to which one comes first.

CHAIRMAN SIEBER: I don't either.

MEMBER BONACA: The important thing is that before walking into the license renewal period one looks at, potentially, what happened from the EPU. And if there are effects, that that could be addressed in license renewal, then they would be addressed.

I mean, I would consider license renewal a living program, anyway, because you are learning as you go, and you are factoring operating experience in it.

CHAIRMAN SIEBER: Right, I agree. In fact I think that the methods that you propose are the reasonable way to do things for all of us to keep all these issues separated, so we address the right issues for the right reasons.

So, for example, if we have a question

about a large transient testing, we will deal with that question at the time of EPU.

MR. COUCH: And when we get ready to talk about EPU, most of the same guys here will be back to talk to you.

CHAIRMAN SIEBER: Let's hope so.

MEMBER BONACA: That is an interesting point. One of the reasons why I think we made faces about not having those tests done, clearly, has to do with the fact that this is a unique case.

I mean, there is a lot of replacement of piping that took place, and so on and so forth. Because we have accepted not having measured transient tests, for all the EPUs we have reviewed to date.

So what is the difference with this? I think the reason why we cringed a little bit, as we are thinking about it, is because so much replacement has been done, so much restoring, refurbishing, and so on and so forth, that it is somewhat different from the others we have looked at.

I don't know we should talk about this.

CHAIRMAN SIEBER: Well, when we get there we will deal with it.

MEMBER BONACA: Yes.

MR. BARTON: I struggle why it is

separate. You do a test program, you have to restart this unit, as part of the test program you are going to go to a power level that this plant has never seen.

CHAIRMAN SIEBER: That is true.

MR. BARTON: I have trouble separating that question from EPU.

MEMBER DENNING: No, I don't think we are separating an EPU.

CHAIRMAN SIEBER: You have to have EPU as a license condition, before you go all the way through their startup test program. Otherwise you stop at 83 percent.

MEMBER DENNING: Exactly.

CHAIRMAN SIEBER: And so, to me, that is okay.

MEMBER BONACA: We will try to be as, you know, as structured as we can.

CHAIRMAN SIEBER: Yes.

MEMBER BONACA: On the other hand, I mean, again I think as statutory responsibility of the ACRS is that we are, we have a different kind of -- we can't be boxed by just simply the rules that says we have to look at a situation and address it.

CHAIRMAN SIEBER: Absolutely. And, in fact, that is why this committee is structured the way

it is. Okay, go ahead.

MR. COUCH: To do a little short summary here.

CHAIRMAN SIEBER: Okay.

MR. COUCH: Of where we have been today. We talked about the fact that there are these three major issues that have been approved by the NRC. There is the license renewal that we submitted, the current license, there is the EPU and unit 1 restart.

And while you, since we are all human, you can't totally divorce one from the other in your mind, you've got to consider the effects, back and forth between the two.

But, as we emphasized here, once we get to the point that we are going to write the SER, and approve the SER, at that point we do have to separate them because, from a legal standpoint, we cannot, as we have been instructed, we cannot approve license renewal based upon EPU conditions, because it is an implicit approval of EPU.

So we will go through these, we will be back to talk to you about EPU. And, obviously, if we need to address the ACRS as part of unit 1 restart, we will do that. But as we've talked, we do not think that the ACRS approval of unit 1 restart is required.

But we are, obviously, available to come talk to you if needed.

CHAIRMAN SIEBER: I guess that is a legal question, and since I'm not an attorney I can't give a legal opinion. On the other hand, that is my understanding, also.

MEMBER DENNING: But if they want to go above 83 percent power, obviously, there is going to be some approval for that.

CHAIRMAN SIEBER: Well, that is a different issue altogether. These are pretty bold steps, and the ACRS has a right and an obligation to review what it deems is important from the safety perspective, whether it is in the statutes, or the rules, or not.

And on that basis I think there is a lot of things that will happen during the restart. You have made a lot of changes to the plant for I'm sure many good reasons.

On the other hand I have asked for the restart panel's report to be sent to us for our review, and should we have any comments on it, we will provide it.

On the other hand this is not a legalistic roadblock that neither the Staff, or TVA can

anticipate being there. But if there are interesting things, where we have questions, we will certainly address it.

MR. COUCH: So the final point here, we are not lawyers, and we do have one lawyer in the room, but we are not lawyers. But it is our understanding that when we get to the point we are ready for restart, it will be a decision made by, an approval made by NRR and the regions, to give us approval to restart.

And then, obviously, this issue of going above 83 percent power --

CHAIRMAN SIEBER: That is a different issue.

MR. COUCH: -- is a different issue, it is post restart. So we will expect to have the approval prior to restart.

CHAIRMAN SIEBER: Right.

MR. COUCH: But you can't go above 83 percent power until after restart.

CHAIRMAN SIEBER: I'm going to write that one down.

MEMBER BONACA: This committee will be involved in reviewing the EPU very shortly, I mean, I imagine.

MR. COUCH: Yes. The EPU application is in. Eva, back here, has been working with us, getting the Staff's requests for additional information to us. We've got the first set of RAI's in draft form.

She is about to give me, I think she said, 54 more questions here shortly. And so we are in the process of writing the response to those, and so --

MEMBER BONACA: We will try to -- we will have to build three hats. We will change, interchangeably. But we will be reviewing all this in the same period of time. So it is --

CHAIRMAN SIEBER: Do we have three hats? You need three hats, right?

MEMBER BONACA: Yes. Just one note for the upcoming subcommittee on license renewal. Clearly we expect to see the scope typical of license renewal. I mean, typically addressed in the SER, etcetera.

Some points of interest, from today's presentation, for that meeting will be agaIN, this issue of operating experience, and you have some interesting slide here that you can use for that.

The issues of lay-up, and what you have presented to us regarding, you know, what you are proposing. I mean, lay-up conditions, you have a program as well. That information for unit 1 is very

important because I think the committee is going to be asking questions about that.

So that gives you a sense, I mean, what I would expect to see in addition to a normal license renewal agenda, these issues for unit 1.

MR. COUCH: We understand when we come back we will be addressing license renewal for all three units, not just unit 1.

MEMBER BONACA: That is right.

CHAIRMAN SIEBER: Right.

MEMBER BONACA: And you will have something specific for unit 1 regarding the lay-up, and the replacement, you don't have to go through this kind of detail.

MR. COUCH: We were not planning on giving you all the level of detail on what we are doing for unit 1 restart.

MEMBER BONACA: Of course.

MR. SUBBARATNAM: What Dr. Bonaca has said, that was kind of in force, but we don't have any docketed information on the operating experience slide. You probably have to have transmittal from you to us, formally, that we will put with the SER.

MEMBER BONACA: You don't have to change the documents now. The important thing is to

communicate this information, like you communicated to us today.

The reason why I raise this is that I know, and I know other members of the committee are interested in those things. They couldn't make today's meeting, but they are going to ask questions. So be prepared for those.

CHAIRMAN SIEBER: Well, what I would like to do now, I presume that you have concluded your presentation?

MR. COUCH: We are complete.

CHAIRMAN SIEBER: What I would like to do now is ask the members, particularly those who have early flights, as to their comments to the meeting. But before I do that I would point out that I certainly appreciate the work that TVA and its staff put into this presentation.

I thought that it was quite clear, and it contains a level of detail that I felt I needed to see, in order to understand fully what it is that you folks are doing. And I promise that that effort that you put into this was worthwhile as far as expediting our review, and the Staff's review.

So I give you my thanks, and that of my colleagues here for a good presentation, and for

putting forth the effort to make it work out. I thought it was well done.

MR. COUCH: Thank you.

CHAIRMAN SIEBER: What I would like to do is go around the table to other members, and our consultants, to ask for any opinions that they want to share with us, on the record, and I will start with you, Graham.

MR. LEITCH: I think it was very helpful presentation today, particularly was helped by straightening out a misconception I had regarding the list of modifications.

I guess I was confused that those modifications still needed to be done on units 2 and 3. Whereas the vast majority of those have already been done on units 2 and 3, except for those associated specifically with EPU.

It has really helped clarify for me. Because, as we say, there is three issues going around here, the restart, the license renewal, and the EPU. And it is just hard to get all these in clear focus. And that helped me.

I guess my one residual concern is the testing program. And admittedly this is an EPU issue. And my concern is the large scale transient tests. I

particularly am concerned about closure of the MSIVs, at the higher power level, and whether we are really sure that demonstration at essentially zero power level, or some lower power level, that they will close in 3 to 5 seconds.

Whether that translates into the fact that they will close in the prescribed time at the new one hundred percent power level, that may or may not be the case. I just don't know whether that has been demonstrated or not.

But I think it may be valuable to conduct such a test to demonstrate not only that they close, but to demonstrate the effect of such a transient on the rest of the plant equipment, pipe movement, and so forth.

But, as I say, that is an issue that will come up at the discussion of the extended power, and I just wanted to signal, in advance, that I do have some concern in that area. That is basically all I have.

CHAIRMAN SIEBER: That is it? Mr. Barton?

MR. BARTON: Well, I think the meeting helped me in really understanding what specifically is being changed in the plant prior to restart, how they are organized, what their restart program is all

about, which really was not that clear before today.

So I think they did a really good job of that. The questions that I had regarding what they were doing with inspections, and requalification of personnel, etcetera, were all answered.

And I think the only thing I have is the same question I related earlier, and the one that Graham just brought up, which is an EPU issue, so I will talk about it at EPU time.

CHAIRMAN SIEBER: Right. And I guess that is a concern of mine, also.

MR. BARTON: I am not familiar with any program that never really did a full power type of transient.

MEMBER BONACA: An issue with the LRA you had some comment before in writing?

MR. BARTON: I didn't have it on --

MEMBER BONACA: So you feel less concerned now?

MR. BARTON: What is that?

MEMBER BONACA: You feel less concerned about some of the issues that you raised?

MR. BARTON: Yes.

CHAIRMAN SIEBER: Okay. Is that it?

MR. BARTON: Yes.

CHAIRMAN SIEBER: Okay, Dr. Denning?

MEMBER DENNING: Well, today's meeting was really quite helpful for me, because I came in quite concerned about the separation of the EPU and license renewal, and I think that the position that Mario has taken is really quite honest, how we deal with that separability.

I think that operating experience is the key, and that we do need some additional assurance in the periodic inspection program and that is probably the key by which you get that.

So I think that as far as unit 1 is concerned, that I am no longer struggling with a logic of life extension before one is really addressed extended power, when in reality its life will be extended beyond that.

I do think that, from that logic, there is a potential that one could approve license renewal, but that it will never be approved at the power for which the plant is being redesigned.

I mean, it could, the Staff could not approve the full upgrade. I don't think that that is going to happen, but I think that is a possibility.

With regards to the EPU and startup separability, in one respect they are not separable.

And that is that in the power uprates, before we have addressed this question of just how do they get to power, and even the question of do they have to do a major trip.

And I think that -- but the conditions under which, I mean, these are different conditions from what we have seen before. It is premature to discuss that in detail.

But, Graham, I can assure you that this is an issue that is going to be high on our plate when extended power uprates are considered.

CHAIRMAN SIEBER: Okay, thank you.

MEMBER DENNING: Before you get to Tom, let me clarify something to Mario. He asked me whether I had strong issue with the LRA. I have an issue with the timing of the application, the operating experience piece. I still have a concern with that, 20 years operating. That is still open in my mind, also.

MEMBER BONACA: For the timing?

MEMBER DENNING: The timing, yes.

CHAIRMAN SIEBER: Okay. Dr. Kress?

MEMBER KRESS: Well, I will make it unanimous, in the meeting being very helpful in understanding the changes, and the differences between

restart, license renewal, and extended power uprate. So I add my thanks for a good presentation.

I guess I differ, a little bit, on the transient testing. I personally would have thought that it should be a condition for restart, even at the 83 percent level, because this thing has sat there a long time, and they have made substantial improvements and changes.

And I think it is almost equivalent to the initial startup. So I think the restart transient testing is going to be an issue, and I think it ought to be an issue with restart. But certainly an issue with extended power uprate.

At this point I don't really see any problems with their restart program. I think they have handled it very well, and they have the experience with units 2 and 3, and I think that is a very nice looking program.

The one thing that did bother me, and it is the same problem I have had with any power uprate, and any license extension, that is the PRA seems to be limited to the level 1s, and modified level 2.

And I know that is all the rules seem to require. But I would think, if I were going to add another plant to this site, I know it is already

licensed for three, and I'm going to uprate power at all three of them by 20 percent, I would do, if I were the operator, I would want to see a level 3, and see what effect it has.

Now, this may be part of the environmental impact statements, but once again, the SER doesn't seem to know the environmental impact statement exists, and vice versa.

I think the ACRS would like to know what impact it has on risk, and I'm not thinking just the individual risk, I'm thinking the whole environmental impact.

So that is one thing that bothers me, and I don't know what to do about it. But other than that I think that things look pretty good for the whole thing, the license renewal and the restart, and the power uprate.

CHAIRMAN SIEBER: I guess I will make a comment about the PRA. PRAs, to my knowledge, don't model aging, per se. It can't tell how thick the pipe is, and how close it is to failure.

And it doesn't model margin, because it uses a go, no-go success criteria for a lot of functions. So when you say I'm going to have an EPU, or some other change to the plant, and you don't model

the change, but you produce two different PRAs and say this is the delta, to me, I'm sort of unimpressed.

And I would like to see the whole art and science. And I think there is a little bit of both of that in PRAs. I would like to see that improved before we make decisions totally founded on PRA results.

On the other hand PRAs have really helped us a lot, and helped the industry improve the safety of the plant. And it puts things in perspective.

So I'm not here to say that it is no good, I'm just here to tell you that it needs continued development, in a lot of ways, in order to be useful in every application.

And so I will make that statement. And probably someone will tell me, but you are all wrong on that, right? I see --

MEMBER DENNING: You are only 60 percent wrong.

MEMBER KRESS: Maybe 70.

CHAIRMAN SIEBER: We will discuss this at a more appropriate time. But, in any event, what I would like to do now is ask Dr. Bonaca if he has any final comments.

MEMBER BONACA: I think I share pretty

much the views of the committee. I already raised my issues today. One is, again, the need for documenting the applicability of unit 3 and 2, but I think that is -- because it is not as simple as that.

There is much more that has been offered on the plate to make the license renewal acceptable. And what is offered on the plate is including, for example, the periodic inspection program. That is a critical item.

It seems to me that in license renewal all you are asking for, if you don't have enough information, is that you inspect. And you have a licensed program. And the licensee is offering that.

So, therefore, I think the substance of the issue, ultimately, is there. However, from a perspective of clarity, communication to the public, and so on and so forth, is important and this should be documented in the SER, so that we understand how it is being done.

So it is a question of documentation, more than anything else, in my judgement. Other members of the committee will have to accept that, too. But I think we have that strength of belief right now.

I think that that issue of committing to this periodic inspection is very good. I think, for

me, it addresses many of the substantive issues that I have with license renewal.

I think we have a clear understanding of what it means. We discussed the periodic inspection, and what it will mean, although it is not written right now.

Regarding the EPU and the testing, I tend to think like Tom, in a way. I mean, it is a significant change in this plant. I think that it is almost like rebuilding the plant.

And so I was thinking about, and I was support of operations, and I would think that it may be problem. I will think about that when it comes to the EPU. And then, again, I want to thank TVA for the presentation, for having come here.

Clearly we got a level of detail that we never got when we were in Browns Ferry. I mean, we simply didn't have the time. So this helps a lot.

CHAIRMAN SIEBER: Okay, thank you. And I guess I will just add a couple of last comments. I particularly endorse Dr. Bonaca's comments, and I again say that you folks have done a good job in things that were a couple of weeks ago, sort of mystifying, are now quite clear to me, and very helpful.

So I truly appreciate the effort. I also was concerned that the Staff and the licensee, and us, would end up with three different events going on, two applications, and the restart, that those issues would become mixed.

And I think that in order for us to do the right job on each application we have to only consider the parts of the application that apply to that licensing action.

And, to me, that clarifies things quite a bit, and it allows us to pay attention to the right issues, at the right time. So I think that TVA has really helped itself by putting things together the way that it has.

And I would also like to appreciate the Staff for getting out the SER for our review, and hopefully things will go well, as we progress through this final licensing action.

Do you have any comments that you would like to make about this meeting?

MR. COUCH: We appreciate the opportunity to come and talk to you, we are glad we have cleared up some things. And we recognized, when you all were there in August, that it was a tremendous amount of information to try to absorb.

We have been absorbing this now for four years. So this is second nature to us. And for you guys to step in there, basically, cold and understand the scope of all these three issues, and everything, we were not surprised that there were some misunderstandings and confusions, and things.

So we just appreciate the opportunity to come back now and hopefully to clear up a lot of this stuff.

CHAIRMAN SIEBER: Well, the issues in August were when we would ask a question, well what is it specifically that you are going to do, what are you going to change out. And the answer was almost everything, or it would be everything but, you know?

Maybe we won't do this and do that, and then you go out in the plant and see things, and obviously you weren't going to do everything. And all we think you ought to do are the right things, okay?

And so this additional detail that you provided us now has been very helpful, and at least to me, and I'm sure my other colleagues, in knowing exactly what it is that you intend to do, what you have already done, what the condition of the plant is, and what the issues are that we need to concern ourselves with as we go along.

And I think that we have accomplished that.

MR. LEITCH: And just to carry that thought one step further, October 5th we are talking about license renewal.

CHAIRMAN SIEBER: Right.

MR. LEITCH: And I think we can focus on license renewal for the October 5th. Now, in this section here, you touched briefly on license renewal, because that wasn't the purpose of today's meeting, and you talked mainly about aging management programs.

We will, obviously, have a lot of questions about scoping issues, and about TLAAs, and the various TLAAs that you went through, in addition to the aging management programs. But that will be focused on license renewal.

And I just wanted you to know that oftentimes a great number of our questions focus particularly on TLAAs.

CHAIRMAN SIEBER: In fact I might ask Dr. Bonaca, since he will be Chairman for the October 5th meeting, if there are any particular things that you want to see, or hear about during that meeting.

MEMBER BONACA: Well, I thought the application was pretty straightforward insofar as the

units 2 and 3. I mean, the big difference is from normal applications on unit 1.

So I will go through the normal presentation that we have regarding your application. It may be different from what you have right now in the application itself, because things have matured and changed since you came in.

But most of the time is spent by the Staff reviewing the SER. So one last comment I wanted to make, by the way, in regards to today's meeting, is the point that John Barton raised on the timing of your application, the concern he has.

And why it is so difficult to separate all these issues. I know other members also have the same concern. If the application had been submitted with a closure, say, to come on the year 2010, which means folding in experience after restart and power uprate, we would be asking questions about the results of the power uprate.

So it is hard for us to simply box ourselves in at the time when we are going to review all these things, one to the other. There are way to address this issue. I mean, we already have provided a way for Dresden and Quad Cities, which is endorsed now by the GALL report, which is, you know, before

walking into licensing you do your degradation and document it.

But that is one way I can see how you can address this issue. But it is hard for us not to think in terms of everything that is going to take place, because it is going to be taking place simultaneously.

I mean, it is going to go up, and go to EPU before it goes to the license renewal. So, anyway, I'm saying this because I know the concern with timing is in the mind of some members, and the full committee will have that question.

CHAIRMAN SIEBER: Any other comments by anyone?

(No response.)

CHAIRMAN SIEBER: I think we have met the requirements of the agenda and our schedule. So, with that, I would like to adjourn the meeting, and thank everyone who participated very much. The meeting is adjourned.

(Whereupon, at 4:20 p.m., the above-entitled meeting was adjourned.)

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 Plant License Renewal Subcommittee

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.

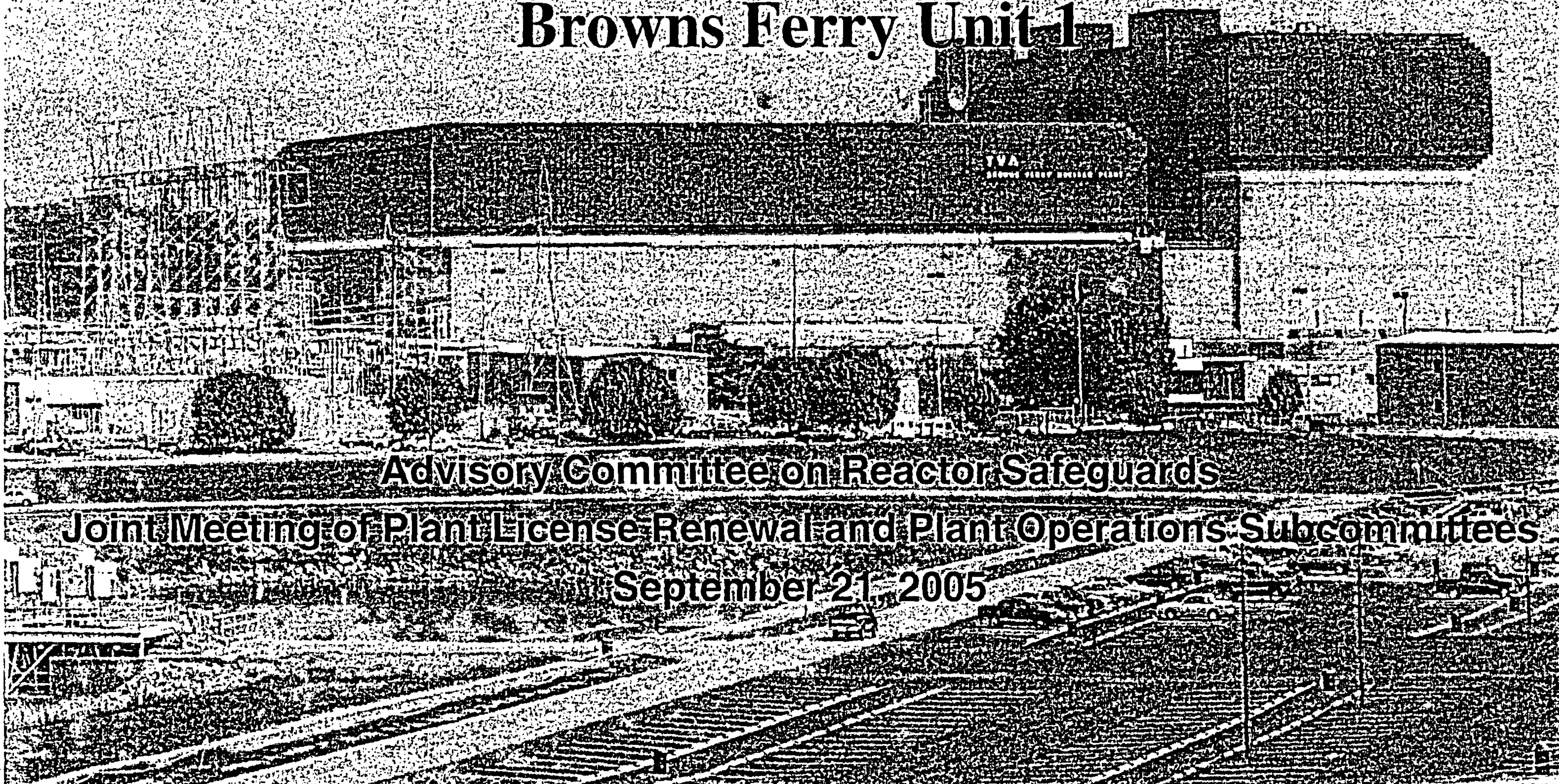
Donna Willis

Donna Willis
Official Reporter
Neal R. Gross & Co., Inc.

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT

TVA

Browns Ferry Unit 1



Advisory Committee on Reactor Safeguards

Joint Meeting of Plant License Renewal and Plant Operations Subcommittees

September 21, 2005

Agenda

- Regulatory Background
- Browns Ferry Unit 1 Fidelity with Units 2 and 3
- License Renewal Application
- Extended Power Uprate Impact on License Renewal

Summary

- Three Major NRC Approval Issues
  - License renewal at current power
  - Extended Power Uprate
  - Unit 1 restart
- Plan for Integration of the Three Issues Coordinated with NRC Staff
- ACRS Approval Needed for License Renewal Application and Extended Power Uprate
- NRC Staff Approval Required for Unit 1 Restart, License Renewal Application, Extended Power Uprate
- Final NRC Approval Required for Unit 1 Restart (NRR and Region II Administrator)

Regulatory Background

- All Three BFN Units are General Electric Boiling Water Reactor 4, with a Mark I Containment
- Designed and Constructed by TVA
- Units 1 and 2 Licensed in 1973 and 1974, Respectively
- Both Units Shutdown after March 22, 1975 Fire
- Units 1 and 2 were Returned to Service in 1976 and Operated until 1985
- Unit 3 Licensed in 1976 and Operated until 1985
- Approximate Years of Operation
  - Unit 1 – 10
  - Unit 2 – 23
  - Unit 3 – 18

Regulatory Background

- All Three BFN Units, Shutdown in March 1985, Because of Regulatory and Management Issues
  - NRC issued a "show cause" letter for all TVA nuclear plants in September 1985, under 10 CFR 50.54 (f), and requested TVA to specify corrective actions
  - TVA submitted the Nuclear Performance Plan in August 1986. It outlined the steps needed to restart the units.
    - Management and organizational changes
    - Process and program improvements
    - Special programs
  - TVA committed to obtain NRC approval prior to restart of any unit

Regulatory Background

- TVA Implemented the Unit 2 Restart Plan, Obtained NRC Approval, and Restarted Unit 2 in May 1991
- TVA Proposed Regulatory Framework for Restart of Units 1 and 3 in July 1991, Outlining Improvements to the Unit 2 Restart Plan Based on Lessons Learned from the Unit 2 Restart
- NRC Approved the Regulatory Framework in April 1992
- Unit 2 was Removed from the "Problem Plant List" in June 1992
- TVA Implemented the Unit 3 Restart Plan, Obtained NRC Approval, and Restarted Unit 3 in November 1995

Regulatory Background

- NRC Removed Units 1 and 3 from the "Watch List" in June 1996. Unit 1 Removal was Based on TVA Commitments to:
  - Implement the same special programs employed for Unit 3 restart
  - Not to restart Unit 1 without NRC approval

- First of Four Consecutive INPO 1 Ratings Received in 1998

- TVA Board of Directors Decided in May 2002, to Restart Unit 1 after Detailed Study and Supplemental Environmental Impact Statement

Regulatory Background

- TVA Submitted a Proposed Update to the Regulatory Framework for Unit 1 in December 2002
  - Addressed regulatory requirements (outstanding Bulletins, Generic Letters and Three Mile Island items deferred for Unit 1), special programs, commitments, and Technical Specification changes to be completed for restart
- Unit 1 NRC Oversight Governed by Manual Chapter 2509 "Browns Ferry Unit 1 Restart Project Inspection Program"
  - Applicable to Unit 1 through restart until all cornerstones are monitorable under the reactor oversight process
  - Establishes restart oversight panel (tentatively scheduled to begin in Fall 2005) to provide recommendation to Region II Regional Administrator and Director of Nuclear Reactor Regulation on Unit 1 restart approval

Regulatory Background

- License Renewal Application Submitted December 31, 2003 for Units 1, 2, and 3
  - Consistent with Generic Aging Lessons Learned
  - Applies to current licensed thermal power of each unit
- License Renewal Approval Expected in June 2006
- Extended Power Uprate Application Submitted June 28, 2004 for Unit 1 and June 25, 2004 for Units 2 and 3
  - Consistent with General Electric's Extended Power Uprate Topical Reports
  - Incorporated all lessons learned and requests for additional information from previous industry Extended Power Uprate applications
  - Separate submittal for Unit 1 since Units 2 and 3 previously uprated 5%
- Extended Power Uprate Approval Expected Prior to Unit 1 Restart (May 2007)

Unit 1 Project Objective

- Maximize Unit Fidelity
  - Utilize existing BFN design criteria, design process, design calculations
  - Utilize TVA procedures, programs, and processes *(Procurement, Work Control, Nuclear Performance Plan)*
  - Scope of Unit 1 restart project incorporated
    - The same restart programs as Units 2 and 3
    - Upgrades installed on Units 2 and 3 since restart
    - Capital projects on the Units 2 and 3 five-year plan through May 2007, including Extended Power Uprate and License Renewal
  - Unit 1 will be operationally the same as Units 2 and 3 (same systems, equipment, operating procedures, Technical Specifications, Updated Final Safety Analysis Report)
    - Obsolete equipment replacement
    - Extended Power Uprate lead unit
    - Deletion of Low Pressure Coolant Injection Motor Generator sets
    - Outage modifications sequence
- Return Unit 1 in a Better Condition than when it was Originally Licensed

Unit 1 Project Description

- Summary of Unit 1 Major Issues
  - Nuclear Performance Plan
    - °Component and piece part qualification
    - °Containment coatings
    - °Environmental Qualification
    - °Flexible conduit
    - °Instrument sensing lines
    - °Moderate energy line breaks
    - °Seismic design
    - °Design Baseline Verification Program
    - °Electrical issues
    - °Fire Protection – Appendix R
    - °Fuse Program
    - °Intergranular Stress Corrosion Cracking
    - °Restart test
  - Performance upgrades
  - License Renewal
  - Extended Power Uprate

Unit 1 Project Description

- Other
  - Station blackout
  - Anticipated Transient Without Scram Rule
  - BWRVIP
  - Generic Letters – 24
  - Bulletins – 14
  - Three Mile Island action items – 11
  - Technical Specification changes – 21

Unit 1 Project Description

- Lay-up Program
  - Purpose
    - Preserve the asset for potential restart of the unit
  - Criteria
    - EPRI NP-5106, "Sourcebook for Plant Layup and Equipment Preservation", Revisions 0 (1987) and 1 (1992)
  - Types of layup
    - Dry
      - Systems
      - Components
    - Wet

Unit 1 Project Description

- Systems in Layup
  - Dry
    - Core Spray
    - Reactor Core Isolation Cooling
    - High Pressure Coolant Injection
    - Residual Heat Removal
    - Condensate
    - Feedwater
    - Off Gas
    - Main Steam
  - Wet
    - Reactor Vessel
    - Recirculation
    - Control Rod Drive
- Results met or exceeded EPRI Guidelines
- No credit was taken for the lay-up program in determining the acceptability of structures, systems, or components for Unit 1 restart

Unit 1 Project Description

- Assessment of Unit 1 Condition
  - Identified attributes of structures, systems, and components necessary for engineering analysis to ensure design criteria and standards met
  - Performed walk downs and ultrasonic inspections of Nuclear Steam Supply Systems and Balance of Plant Systems
  - Additional visual inspections were performed during component replacement / refurbishment
  - Remote inspections of Core Spray, Residual Heat Removal pump suction, steam lines

Unit 1 Project Scope

- 39 Unit 1 Mechanical Systems in Scope of Unit 1 Recovery
- 47 Unit 1 Mechanical Systems in Scope of License Renewal
- 1 System Completely Replaced
- 33 License Renewal Systems Partially Replaced / Modified
  - 35% of large bore piping replaced
  - 25% of small bore piping replaced
  - 15% of valves replaced
- 8 Systems in Operation to Support Units 2 and 3
- List of Modifications
- Three Example Systems
  - High Pressure Coolant Injection
  - Reactor Water Cleanup
  - Feedwater

High Pressure Coolant Injection

- Function of System
  - The High Pressure Coolant Injection System provides core cooling / injection for small breaks and depressurizes the reactor coolant systems to allow low-pressure coolant injection and core spray flow.
  - Provides reactor vessel make-up, pressure control, and decay heat removal during transient events
- Modifications to System
  - Replace various cables, relays, pressure switches, and transmitters to resolve environmental qualification, separation, and breakage issues
  - Replace valves and motors for environmental qualification and Generic Letter 89-10 Motor Operated Valve testing requirements
  - Refurbish / upgrade GE supplied High Pressure Coolant Injection turbine / pump skid to include impeller replacement and seismic requirements

Reactor Water Cleanup

- Function of System
  - Maintains high reactor-water purity to limit corrosion, chemical interactions, fouling, and deposition on reactor heat transfer surfaces
  - Removes corrosion products to limit impurities available for activation by neutron flux and the resultant radiation from deposition of corrosion products
  - Provides a means for removal of water from the reactor vessel during normal operations
- Modifications to System
  - Remove and replace process piping
  - Replace Motor Operated Valves for GL 89-10 requirements
  - Replace pumps and regenerative heat exchangers
  - Reroute flow to the reactor water cleanup pump suction resulting in lower temperature water entering the pumps
  - Replace instrumentation

Feedwater

- Function of System
  - Provides water at an elevated temperature to the reactor vessel during normal plant operations
- Modifications to System
  - Replace valves due to stellite content
  - Install Digital Feedwater Control system
  - Install zinc injection passivation system
  - Replace Reactor Vessel Level Indicating System reference and sensing lines
  - Replace rotors on feedwater pump turbines to support Extended Power Uprate conditions
  - Replace reactor feedwater pumps, pump / turbine couplings, bearing temperature, and vibration monitoring instrumentation to accommodate increased flows for Extended Power Uprate

Unit 1 Project Scope

- Long-Term Passive Component Replacements
  - Condenser tubes
  - Extraction steam piping
  - Turbine cross-over / cross-under piping
  - Reactor Building Closed Cooling Water heat exchangers
  - Drywell structural steel and electrical penetrations
  - Large and small bore piping
  - Reactor Pressure Vessel safe ends
  - Residual Heat Removal Service Water piping in the Reactor Building

Unit 1 Project Scope

- Long-Term Passive Component Replacements
  - Drywell coolers
  - Cable tray, conduit, and support installation
  - Pipe hanger installation
  - GE in-vessel inspections
  - Torus coatings
  - Cables

Unit 1 Project Scope

- Other Modifications / Refurbishments
  - Control Room Design Review modifications
  - Recirculation pump variable frequency drives
  - Digital Electro-Hydraulic Control system
  - Main generator rewind and rotor balanced
  - Close in-fault protection in switchyard
  - Common accident signal
  - Reactor Core Isolation Cooling turbine reassembly and upgrade
  - Refueling bridge crane modifications
  - Large pump and motor refurbishment
  - Valve replacement / refurbishment

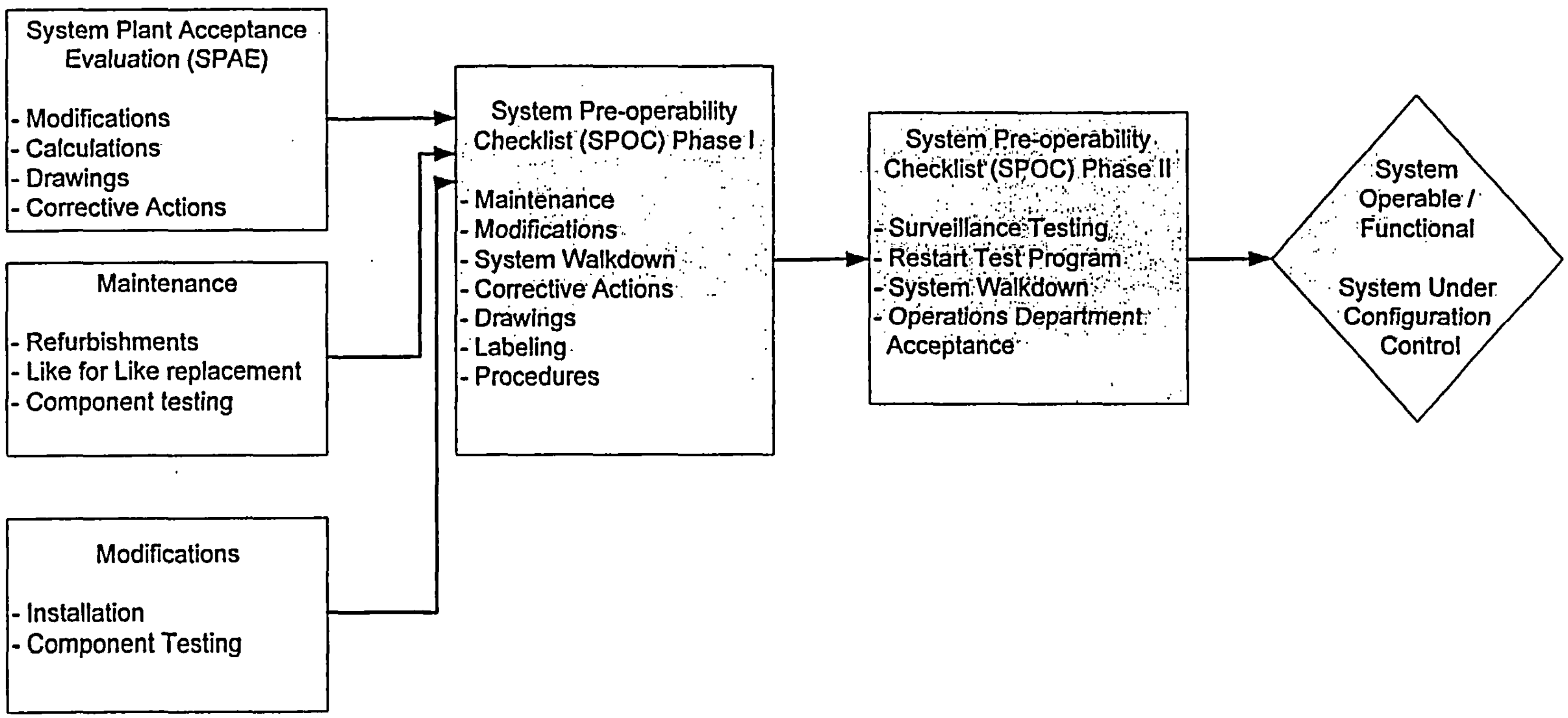
Unit 1 Project Scope

- Extended Power Uprate
  - Approximately 40 modifications to be discussed later
- License Renewal
  - No modifications required

System Return to Service Process

- Process to Ensure all Tasks are Completed Prior to Return to Service
  - Engineering
  - Maintenance
  - Modifications
  - Operations
  - Licensing
- Same Process as used on Units 2 and 3
- Six Systems Returned to Operation

System Return to Service Process



Restart Test Program

- Purpose – to Verify that Systems are Capable of Meeting Safe Shutdown Requirements for Each Mode of Operation as Defined by the Safe Shutdown Analysis
- Verify Design and Operation of Plant are within Licensing Basis
- Commitment to NRC to Test Safety Related Modes of Systems
- Non-safe Shutdown Functions Tested by Post Modification Tests / Component Tests
- Restart Test Program the Same as Performed on Units 2 and 3
- Significant Oversight of Testing by Nuclear Assurance, Restart Test Group, Plant Operations Review Committee, Nuclear Safety Review Board, and NRC

High Pressure Coolant Injection

- Post Modification Testing, Calibrations, Surveillances
  - Valve stroking and timing
  - Leak testing
  - Component calibrations
  - Cold quick start
  - Vessel injection test and tuning
- Restart Test Program Requirements Based on System Modes
  - Automatic High Pressure Coolant Injection system initiation on low water level or high drywell pressure. Includes auto transfer from condensate storage tank to suppression pool and verification of turbine stop valve closure on high reactor water level and that subsequent low water level will open stop valve.
  - Verify system minimum flow rate on auto initiation signal
  - Verify minimum flow bypass valve function and flow
  - Close High Pressure Coolant Injection steam supply on isolation signals

Reactor Water Cleanup

- Post Modification Testing, Calibrations, Surveillances
  - Functional testing of Reactor Water Cleanup pump interlocks
  - Valve stroking and timing
  - Local leak rate testing
  - Component calibrations
- Restart Test Program Requirements Based on System Modes
  - Close isolation valves on Primary Containment Isolation signal
  - Close isolation valves on Standby Liquid Control Initiation
  - Close isolation valves on high area temperature signal

Feedwater

- Post Modification Testing, Calibrations, Surveillances
  - Functional test and tuning of Digital Feedwater Control system
  - Functional test of reactor feedwater pumps and turbines
  - Functional test of zinc passivation system
  - Component calibrations
  - System leak test
  - Valve test for instrument line excess flow check valves
- Restart Test Program Requirements Based on System Modes
  - Verify pressure and water level signals to Reactor Protection System, Emergency Core Cooling Systems, Primary Containment Isolation System, Main Steam System, Feedwater Control System (main turbine and feedwater turbine trip), Recirculation System (Anticipated Transient Without Scram / Alternate Rod Injection), Diesel Generator start, and Automatic Depressurization System
  - System piping vibration test at full power

Integrated/Power Ascension Test Program

- Phase 1 Testing
  - Source Range Monitor and Intermediate Range Monitor testing
  - Control Rod Drive testing
  - Containment integrated leak testing
  - Reactor Pressure Vessel hydrostatic testing
  - High Pressure Coolant Injection and Reactor Core Isolation Cooling runs on auxiliary boiler
  - Backup control panel testing
- Management Assessment of Test Results with Plant Operations Review Committee and Plant Manager Approval Prior to Proceeding

Integrated/Power Ascension Test Program

- Phase 2 Testing (< 55% Power)
  - Initial criticality and shutdown margin testing
  - Source Range Monitor and Intermediate Range Monitor overlap
  - Thermal expansion walk downs
  - Reactor feedwater pumps overspeed testing and balancing
  - High Pressure Coolant Injection and Reactor Core Isolation Cooling testing
  - Safety relief valve cycling
  - Electrohydraulic control tuning / testing
  - Turbine roll / balancing
  - Core thermal limits / computer testing
  - Local Power Range Monitor calibrations
  - Average Power Range Monitor calibrations
  - Scram time testing
  - Reactor scram
- Management Assessment of Test Results with Plant Operations Review Committee and Plant Manager Approval Prior to Proceeding

Integrated/Power Ascension Test Program

- Phase 3 Testing (55% to 83%)
  - Reactor Feedwater Pump tuning / testing
  - Recirculation pump variable frequency drive tuning / testing
  - Electrohydraulic control tuning / testing
  - Recirculation flow calibration
  - High Pressure Coolant Injection and Reactor Core Isolation Cooling vessel injection and tuning
  - Recirculation pump variable frequency drive runback test

- Management Assessment of Test Results with Plant Operations Review Committee and Plant Manager Approval Prior to Proceeding

Integrated/Power Ascension Test Program

- Phase 4 Testing (83% to 100%)
- Performed in Plateaus of 2% to 5%
- Management Assessment at Each Plateau with Plant Operations Review Committee and Plant Manager Approval Prior to Proceeding
- Consists of the Following Testing at Each Plateau
  - Core power distribution
  - Pressure Regulator testing
  - Feedwater System testing
  - Process computer – heat balance and thermal limits verification
  - Reactor Vessel Water Level verification
  - Drywell Atmosphere Cooling System
  - Reactor Building Closed Cooling Water and Raw Cooling Water System monitoring
  - Radiation level monitoring
  - Reactor Pressure Vessel / Feedwater Chemistry monitoring
  - Off gas release monitoring
  - Main Steam Line moisture content monitoring
  - Main Steam, Feedwater, and Recirculation piping vibration monitoring

Large Scale Transient Testing

- No Large Transient Testing to be Performed
  - System functions / actuations tested by comprehensive component and system testing
  - Large scale transient system effects essentially decayed prior to mitigating system actuations
  - Large scale transient at operating conditions not as severe as licensing basis analytical transients
- Minimal Benefit from Test does not Justify the Risk

Other Items

- Three Unit Staffing
- Simulators
- Unit Separation

License Renewal

- Units 1, 2, and 3 License Renewal Application Submitted December 31, 2003
- License Renewal Application at Current Licensed Thermal Power for each Unit
- License Renewal Application Consistent with Generic Aging Lessons Learned
- License Renewal Application Results in 39 Aging Management Programs

Status

- Application Submitted on December 31, 2003
  - Requests for additional information:
    - Total: 230
    - For Unit 1: 30
  - Draft SER with open items issued on August 9, 2005
    - OI-2.4-3 (Section 2.4 - Drywell Shell Corrosion)
    - OI-4.7.7 (Section 4.7.7 - Stress Relaxation of the Core Plate Hold-Down Bolts) – TVA letter dated September 6, 2005

License Renewal
Aging Management Programs

- 39 Aging Management Programs Total
  - 38 are common to Units 1, 2, and 3
  - 1 is for only Unit 1 (i.e., Unit 1 Periodic Inspection Program)

- 12 Existing Aging Management Programs Require no Enhancement Since Consistent with Generic Aging Lessons Learned

- 10 Existing Aging Management Programs Require Enhancing for all Units in Order to Comply with Generic Aging Lessons Learned

- 11 Existing Aging Management Programs Revised to Include Unit 1. Already Consistent with Generic Aging Lessons Learned

- 6 New Aging Management Programs

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring No Enhancement
  - 10 CFR 50 Appendix J Program
  - Above ground Carbon Steel Tanks Program
  - ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program
  - ASME Section XI Subsection IWE Program
  - ASME Section XI Subsection IWF Program
  - Bolting Integrity Program
  - BWR Control Rod Drive Return Line Nozzle Program
  - Diesel Starting Air Program
  - Fuel Oil Chemistry Program
  - Inspection of Overhead Heavy Load and Light Load Handling Systems Program
  - Reactor Head Closure Studs Program
  - Systems Monitoring Program

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring Enhancement in Order to Comply with Generic Aging Lessons Learned (All Units)
  - Buried Piping and Tanks Inspection Program
  - BWR Vessel Internals Program
  - Compressed Air Monitoring Program
  - Electrical cables not subject to 10 CFR 50.49 Environmental Qualification requirements used in Instrumentation Circuits Program
  - Fatigue Monitoring Program
  - Fire Water System Program
  - Inspection of Water-Control Structures Program
  - Masonry Wall Program
  - Reactor Vessel Surveillance Program
  - Structures Monitoring Program

License Renewal
Aging Management Programs

- Existing Aging Management Programs Consistent with Generic Aging Lessons Learned Requiring Revision to Incorporate Unit 1
  - BWR Feedwater Nozzle Program
  - BWR Penetrations Program
  - BWR Reactor Water Cleanup System Program
  - BWR Stress Corrosion Cracking Program
  - BWR Vessel Inside Diameter Attachment Welds Program
  - Chemistry Control Program
  - Closed-Cycle Cooling Water System Program
  - Compressed Air Monitoring Program
  - Environmental Qualification Program
  - Flow-Accelerated Corrosion Program
  - Open-Cycle Cooling Water System Program

License Renewal
Aging Management Programs

- New Aging Management Programs (for all Three Units)
  - Accessible Non-Environmental Qualification Cables and Connections Inspection Program
  - Bus Inspection Program
  - Inaccessible medium voltage cables not subject to 10 CFR 50.49 Environmental Qualification Requirements Program
  - One-Time Inspection Program
  - Selective Leaching of Materials Program
- New Aging Management Program (Unit 1 Only)
  - Unit 1 Periodic Inspection Program

Unit 1 Periodic Inspection Program

- Targeted Unit 1 Periodic Inspections will be Performed after Unit 1 is Returned to Operation to Verify Aging Management Program Effectiveness for Piping that was not Replaced and to Verify no Additional Aging Effects are Occurring

- The Targeted Periodic Inspection Sample Locations will be a Subset of Non-Replaced Piping Locations Inspected for Restart

- The Periodic Inspections will be Performed Prior to Period of Extended Operation

Appendix F (Unit 1 Differences)

- The Basic TVA Principle for the Unit 1 Restart is that all Three BFN Units will be Operationally Identical upon Completion of Unit 1 Restart Activities
- To Meet this Principle, the Unit 1 Current Licensing Basis at Restart to be the Same as the Current Licensing Basis of Units 2 and 3
- Appendix F to the License Renewal Application Describes the Differences Between Unit 1 and Units 2 and 3
- These Differences will be Eliminated Prior to Unit 1 Restart

Appendix F (Unit 1 Differences)

- Appendix F Delineates 13 Areas of Difference
  - Main Steam Isolation Valve alternate leakage treatment
  - Containment Atmosphere Dilution System modifications
  - Fire Protection Program
  - Environmental Qualification Program
  - Intergranular Stainless Steel Stress Corrosion Cracking
  - BWRVIP Inspection and Flaw Evaluation Guidelines implementation
  - Anticipated Transients Without Scram
  - Reactor Vessel Head Spray removal
  - Hardened Wetwell Vent
  - Service Air and Demineralized Water Primary Containment Penetrations
  - Auxiliary Decay Heat Removal System
  - Maintenance Rule implementation
  - Reactor Water Cleanup System

Operating Experience

- 10 CFR 54.17(c):

  An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.

- Unit 1 Met This Requirement

- License Renewal Statement of Considerations (1991)
  - Provides the basis for the 20 years
  - Operating Experience not limited to that of the License Renewal Applicant
  - Regulatory history demonstrates that 20 years of plant specific Operating Experience not required by NRC

Operating Experience

- License Renewal Statement of Considerations
  - NRC indicated willingness to consider plant specific exemptions for application seeking license renewal prior to 20 years before license expires

- Schedular Exemptions Granted by the NRC to 10 CFR 54.17(c)
  - Progressive expansion of scope of Operating Experience justification for such exemptions
    - Reliance on Operating Experience of sister units, other utilities' similar units, and industry wide experience

Operating Experience

- Unit 1 has 10 Years of Operation
- Unit 2 and Unit 3 Operating Experience is Applicable to Unit 1
- Unit 3 Shutdown for 10 Years
  - Extensive layup experience with Unit 3 directly applicable to Unit 1
  - No post-layup aging effects during 10 years of ensuing operation
- Layup Experience from Unit 3 Incorporated into Unit 1 Recovery
  - RHR service water
  - Small bore piping
- Unit 1's Design, Configuration, Operating Procedures, Technical Specifications, and Updated Final Safety Analysis Report Identical to Unit 2 and Unit 3
- Unit 1's Licensing Basis will be the same as that of Unit 2 and Unit 3 at Restart (Appendix F)
- Unit 1 Periodic Inspection Program

Extended Power Uprate Impact on License Renewal

- Extended Power Uprate Applications Prepared Using GE's Extended Power Uprate Licensing Topical Reports (ELTR1 and ELTR2)

- Submittals Provided Information Requested in NRC RS-001, "Review Standard For Power Uprates," Issued December 2003

- Included Information to Address Request for Additional Information Received on Other Plant Dockets

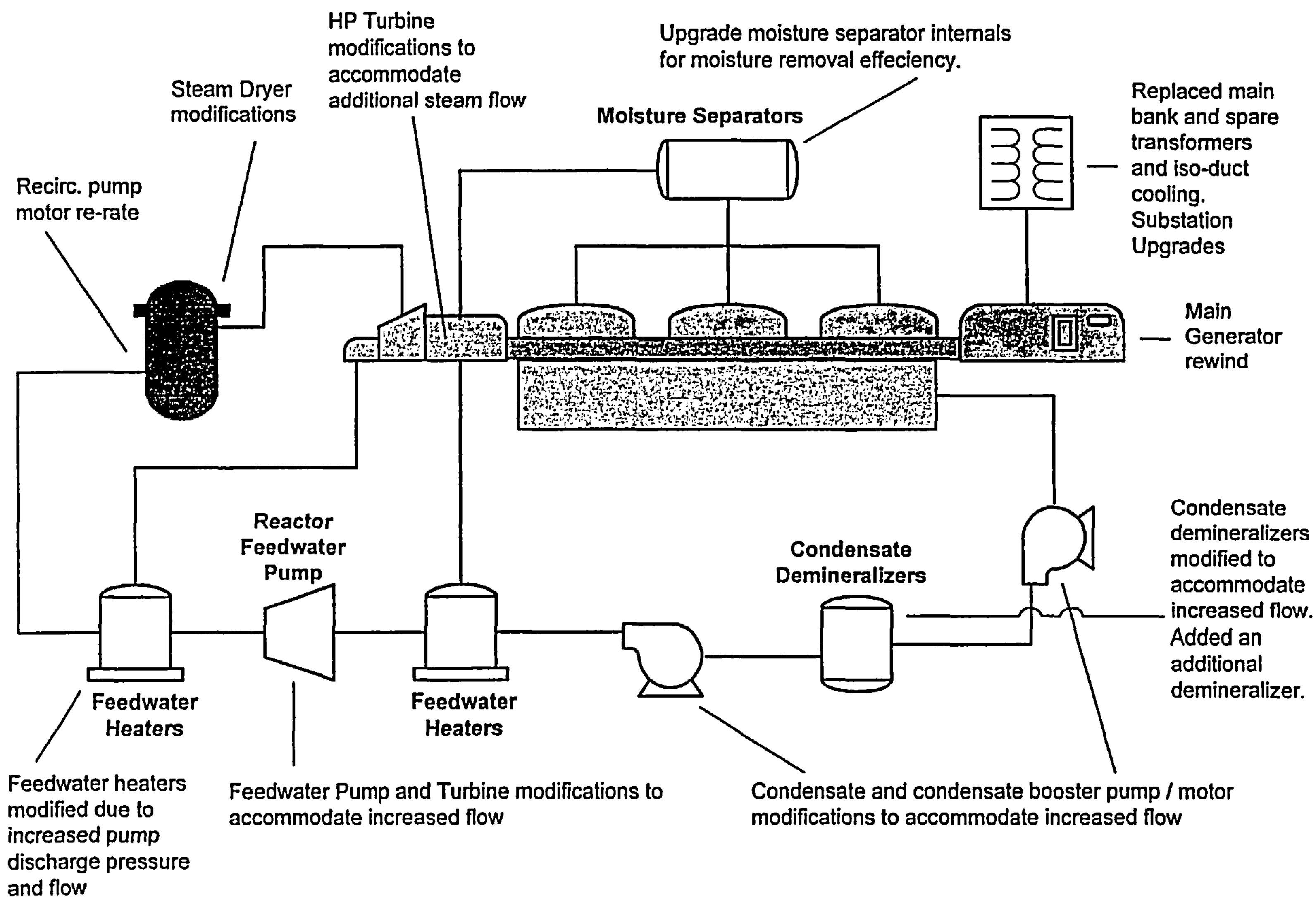
- BFN Unit 1 – GE14 Fuel

- BFN Units 2 and 3 – FANP A-10 Fuel

BFN Extended Power Uprate

	BFN Unit 1	BFN Units 2 & 3
Original Thermal Power	3293 MWt	3293 MWt
Current Thermal Power	3293 MWt	3458 MWt (5% Uprate)
Requested Thermal Power	3952 MWt	3952 MWt
RPV Pressure	30 psi increase	No change (30 psi increase with prior 5% uprate)
Operations	Operationally the same upon implementation of Extended Power Uprate in all three units.	

Modifications Overview



System Effects for Normal Operation

System	Parameter Increases
Main Steam	Steam Flow, Moisture Content
Extraction Steam	Steam Flow, Moisture Content
Heater Drains and Vents	Liquid Flow, Steam Flow
Condensate	Liquid / Steam Flow, Pressure
Feedwater	Liquid Flow, Pressure
Recirculation	Flow, Pump Motor Electrical Load
Primary Containment / Drywell Coolers	Heat Load
Electrical Distribution	Electrical Output
Electrical Supply	Electrical Load
Iso-phase Bus	Air Flow
Reactor Vessel	Steam Flow
Personnel and Equipment Dose Rates	Dose Rate

- No New Aging Management Programs Required to Monitor or Manage These Effects

System Effects for Normal Operation

- Summary
  - Impact of Extended Power Uprate monitored by existing Aging Management Programs such as Flow Accelerated Corrosion Program
  - Extended Power Uprate submittal has been accepted by NRC staff for review with target approval date in Spring 2007
  - ACRS review of Extended Power Uprate as part of Extended Power Uprate submittal and will consider impact on License Renewal

Summary

- Three Major NRC Approval Issues
  - License Renewal at current power
  - Extended Power Uprate
  - Unit 1 restart
- Plan for Integration of the Three Issues Coordinated with NRC Staff
- ACRS Approval Needed for License Renewal Application and Extended Power Uprate
- NRC Staff Approval Required for Unit 1 Restart, License Renewal Application, Extended Power Uprate
- Final NRC Approval Required for Unit 1 Restart (NRR and Region II Administrator)

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT

DESCRIPTION OF MODIFICATIONS PLANNED FOR UNIT 1 RESTART

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
SEPTEMBER 21, 2005

Description of Modifications Planned for Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Main Steam DCN 51112	Provide a seismically rugged alternative leakage treatment (ALT) path for MSIV leakage during a postulated LOCA.	Y
Main Steam DCN 51136	Add capability to place a standby Steam Jet Air Ejector (SJAE) into service from Unit 1 Control Room. Replace various instruments including Main Steam Line pressure transmitters, High Pressure (HP) Turbine 1st stage pressure transmitters, HP and Low Pressure (LP) Steam Flow Transmitters to Reactor Feedwater Pump Turbines, Steam Pressure Indicators to the Steam Jet air Ejectors (SJAEs), Control Valve Steam Chest Pressure Transmitter, Main Steam (MS) Header Pressure Transmitter, Steam Seal Header Pressure Transmitter, High Pressure Turbine Exhaust Pressure Transmitter, and Steam Pressure to Low Pressure Turbine A Transmitter. Replace Main Steam Line Tunnel Leak Detection Temperature Switches with new switches including EQ quick disconnects to prevent moisture intrusion. Install mounting brackets and supports for linear variable differential transformers (LVDTs) used to monitor steady-state vibration of MS piping outside containment during power ascension up to Extended Power Uprate conditions. Provide addition of Auxiliary Boiler steam supply to (SJAE) pressure switches (1-PS-012-80A & -80B), add root valves for new pressure switches, and add interlocks from Auxiliary Steam to SJAE shutoff valves.	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Main Steam DCN 51143	Modify and update the four inboard MSIVs by providing new poppet design, new larger stem, new bonnet, new bolting design, new larger actuator, spring housing modification, adapter plate for solenoid control panel, new limit switches (LS-1 & LS-5), and redesigned switch mounting plate to support EPU. Adjust inboard MSIV position limit switch (LS-5) from the 90% open position to the 85% open position per General Electric Service Information Letter (GE SIL) 568. Replace Main Steam Drain Isolation Valve (MSDIV) FCV-1-55, with an equivalent Flowserve valve due to higher leakage trends in Local Leak Rate Tests (LLRTs). Replace the MSDIV motor actuator with a new environmentally qualified motor (GL 89-10). Replace (4) Main Steam Relief Valve (MSRV) bodies with new bodies and new pilot assemblies. Install nine new pilot assemblies on existing bodies. Replace threaded couplings with socket welded couplings in MSRV tailpipes and install new temperature elements in new welded thermowells. Replace existing Main Steam (MS) System cables with new Class 1E and 10CFR50.49 (EQ) qualified cables between the Electrical Penetration Assemblies (EPA) and the Main Steam System components (inboard MSIV limit switches, MSRV pressure control valves and thermocouples, and MSDIV motor actuator and limit switches). Six (6) of the thirteen (13) Main Steam Relief Valves (MSRVs) are associated with the Automatic Depressurization System (ADS) portion of the Main Steam (MS) System (1-PCV-1-5, -19, -22, -30, -31, and -34). Re-label conduit/cables associated with the ADS MSRVs with the 'IS1' suffix. (Cable/conduit associated with the High Pressure Coolant Injection (HPCI) System will be labeled with the 'IS2' suffix per DCN 51150.) Calculation ED-Q0001-920589, (Division I Cables Requiring Separation to Maintain HPCI-ADS Independence Plus Significant ADS Modifications) has been issued to support this change. Replace the mechanical portion of the Standby Liquid Control (SLC) system inside the drywell consisting of (4) valves (1-SHV-63-12, -538, -539, & 1-CKV-63-526).	Y
Main Steam DCN 51162	Replace equivalent MSRV acoustic monitors, acoustic monitor charge converters, cables, conduit, and junction boxes. Replace equivalent inboard MSIV control valve manifold assemblies. Addition of cables/conduit for limit switches added per DCN 51143.	Y
Main Steam DCN 51173	Modify and update the four outboard MSIVs by providing new poppet design, new larger stem, new bonnet, new bolting design, new larger actuator, spring housing modification, adapter plate for solenoid control panel, and redesigned switch mounting plate. Replace Main Steam Drain Isolation Valve (MSDIV) FCV-1-56 with an equivalent valve due to higher leakage trends in Local Leak Rate Tests (LLRTs). Replace the MSDIV motor actuator with a new environmentally qualified motor (GL 89-10). Replace Control Air flex hoses for MSIVs 1-FCV-1-15, 27, 38, & 52. Provide live-loaded packing for outboard MSIVs and MSDV. Leak-off taps are deleted from new MSIV bonnet design.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Main Steam DCN 51211	Replace all safety-related limit switches associated with the outboard MSIVs. Replace cable and conduit in the Reactor Building associated with the outboard MSIV solenoid valves with new Class 1E and 10CFR50.49 (EQ) cable and splices. Replace cable and conduit in the Reactor Building associated with the inboard and outboard MSIV open/close limit switches with new Class 1E and 10CFR50.49 (EQ) cable (for inboard MSIV limit switches LS-3 and LS-4, see DCN 51162). Replace cables for the MSIV Drain Interlock circuit and reroute cables from a Div II Electrical Penetration Assembly (EPA) to a Div I EPA. Remove the Unit 1 outboard MSDIV local control station. Replace cable and conduit in the Reactor Building associated with the MSRV solenoid valves with new Class 1E and 10CFR50.49 (EQ) cable. Modify control switch locations to ensure required numbers of ADS SRVs are available in case of fire in any area of the plant. Replace cable and conduit in the Reactor Building associated with the MSRV acoustic monitoring with new Class 1E and 10CFR50.49 (EQ) cable. Delete temperature sensors TS-1-17A, -17B, 17C, & -17D from main steam tunnel vault. Replace cable and conduit in the Reactor Building associated with the Main Steam Line Leak Detectors with new Class 1E and 10CFR50.49 (EQ) cable.	Y
Main Steam DCN 51230	Equivalent replacement of each Main Steam Line Flow transmitter. Procure and qualify like-for-like outboard MSIV open/close control valve manifolds. Equivalent replacement of each Main Steam line high flow transmitter. Like-for-like replacement of Main Steam instruments located in the Reactor Building.	Y
Main Steam DCN 51333	Provide additions and modifications to the small bore instrument piping supports inside Drywell for Main Steam and HPCI systems (from respective flow element to Penetrations X-30A, -B, -C, -D, X-32E & F, X-34-A, -B, -C, & -D).	Y
Main Steam DCN 51408	Provide additions and modifications to the small bore instrument piping supports inside the Reactor Building for the Main Steam System (from Drywell Penetrations X-30A, -B, -C, -D, X-32E & F, X-34-A, -B, -C, & -D to the instrument panels in the Reactor Building)	Y
Main Steam DCN 51458	Remove Moisture Separator Drain Pumps (MSDPs) and modify the Heater Drain System to operate without MSDPs. Upgrade internals of each moisture separator to increase capacity and increase moisture removal efficiency from 85% to at least 95% at EPU conditions. Clear MSDP room of Heater Drain piping. Tap off of condensate booster pump discharge header to supply injection water to each drain from the moisture separators. Cut and cap Raw Cooling Water supply and return piping to the MSDP room. Remove handswitches and indication for MSDPs from main control board. Remove the closing feature of the flow control valves when the reactor feedwater to the associated high pressure feedwater heaters is manually or automatically isolated.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Main Steam DCN 60534	Implementation of MSRV auto actuation logic (will be safety-related on Unit 1).	Y
Condensate and Demineralized Water DCN 51113	Provide a drainage path from the reactor well to the condensate storage tanks when the condenser is out of service (GE SIL 427). Provide for oxygen injection into the Condensate System from the Hydrogen Water Chemistry System at suction piping of each condensate pump (GE SIL 136). Upgrade condensate demineralizer precoat pump seal equipment to improve pump seal operation. Add precoat inlet and outlet line pressure gauges to improve demineralizer precoat operation. Provide for hydrogen injection into the Condensate System from the Hydrogen Water Chemistry System into each condensate booster pump suction drain piping. Change valves 1-FCV-2-29A and 1-FCV-2-29B from "fail open" to "fail closed". Change system design conditions for temperature and pressure to support new booster pump pressures at EPU conditions. Modify Condensate pump inlet piping with T-section spool piece to accommodate pump suction strainers. Feedwater heaters A3, B3, and C3 and associated piping are re-rated, and the manway opening for Feedwater Heater C3 is reinforced to support new design pressure at EPU conditions.	Y
Condensate and Demineralized Water DCN 51137	Replace the Condensate Demineralizer Control Panel from existing analog to a new Digital Programmable Logic Control (PLC) panel and provide control capability for 10 vessels. Provide primary and alternate 120Vac power to the new panel via separate 480 V feeds, 480/120Vac distribution transformers, and an automatic transfer switch. Replace 27 existing transmitters with "smart" transmitters and replace associated flow elements. (EPU)	Y
Condensate and Demineralized Water DCN 51174	Modify Condensate/Demineralized Water System piping inside Reactor Building as follows: Remove the 20"X24" Y-connection, anchor the 20" return line, install a blind flange on the 20" carbon steel header, and reconstruct the 24" header. The Demineralizer Water supply line to the drywell is cut and capped downstream of SHV-2-1191 and cut and plugged upstream of Penetration X-20.	Y
Condensate and Demineralized Water DCN 51294	Provide for the retubing of the Main Condenser in the Turbine Building. Material substitution only of tubing from brass to stainless steel.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Condensate and Demineralized Water DCN 51335	Modify the support configuration for a portion of the Condensate Storage and Supply System piping outside the drywell in the Reactor Building.	Y
Condensate and Demineralized Water DCN 51344	Provide for modifications and additions to existing supports for a small portion of the Condensate Storage and Supply System piping in the Reactor Building (branch HPCI Pump Test line connecting to Condensate Supply System piping).	Y
Condensate and Demineralized Water DCN 51463	Upgrade the Condensate Demineralizer System air surge backwash system by adding quick-action type valves and upgraded compressors. This will result in higher tank pressures and improved air surge valve operating times. Crosstie capability for Unit 1 to Unit 2 backwash air systems is provided with the addition of manual valve 1-SHV-2-850A.	Y
Reactor Feedwater DCN 51076	Provide equivalent replacement and addition of cables as a result of design/programs. Revise setpoint and scaling calculations applying the effects of EPU, 24-month fuel cycle, and hydrogen water chemistry. Increase setpoint of instrumentation associated with reactor steam dome pressure. Extend channel calibration and logic system functional test frequencies to 24-months. Lower the Reactor Vessel Water Level -Low, Level 3 setpoint.	Y
Reactor Feedwater DCN 51114	Replace valves FCV-3-75, 76, 77, and others due to their stellite content. Replace sample probe and valve SMV-3-549 per GE SIL 257. Install mounting brackets and supports for linear variable differential transformers (LVDTs) used to monitor steady-state vibration of Feedwater (FW) piping outside containment during power ascension up to Extended Power Uprate conditions. Delete stem leak off valves LOV-3-540, 543, & 548 from valves FCV-3-71, 72, & 73 respectively and replace stem packing with Electric Power Research Institute (EPRI)-style packing. Replace 12 obsolete Hancock globe valves. Install a GE zinc injection passivation system to reduce Cobalt-60 build-up in piping systems where condensate water is utilized.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Feedwater DCN 51163	Replace Reactor Vessel Level Indicating System (RVLIS) reference and sensing lines (four each) to provide more reliable measurement (GL 84-23 and NUREG-0737, Item II.F.2). Replace Reactor Head Seal Leakoff reservoir line, level switch, and reservoir isolation and drain valves. Replace Reactor Head Vent sensing line and flow control valves. Replace Reactor Vessel Main Feedwater inboard isolation valve closed limit switches. Install FW piping vibration monitoring equipment permanent mounting hardware. Replace double vent and drain small bore valves associated with Reactor Vessel Main Feedwater inboard isolation valves.	Y
Reactor Feedwater DCN 51231	Relocate sensing lines associated with penetrations 17A, 17B, 26A, & 26B from penetrations 28A, 28D, 29A, & 29D respectively. Rework sensing lines due to slope concerns and separation of functionally redundant lines for various level instrument loops (of 10 sensing lines involved, 5 are being re-routed and 5 are being reworked). Two new 6-inch, core-bore penetrations are required. Penetrations X-28A, X-28D, X-29A, & X-29D are to be capped. Refurbish panels 25-5A, 5B, 5C, 5D, 5-1, 6A, 6B, 6C, 6D, and 6-1, to include replacement of drain valves, isolation valves, equalization valves, quick-connect fittings, and tubing. Add new panel 25-426 to house LT-3-206 & 207.	Y
Reactor Feedwater DCN 63792	Provide separate power supplies to U1 RFP min-flow valve control circuits.	Y
H2 Water Chemistry DCN 51115	Install a Hydrogen Water Chemistry (HWC) system to reduce intergranular stress corrosion cracking (IGSCC) of stainless steel components in the reactor coolant recirculation piping and lower reactor internals. Relocate Unit 2 valves 2-SHV-66-1135 and 1136 which are currently located in Unit 1. Remove existing Offgas hydrogen analyzer panels, associated Offgas sample tubing, Service Air tubing, Demineralizer water tubing, and sample cooler. Install Offgas monitor panel, sample supply/return piping, supports, and valves. Install four hydrogen area monitor sensors (HAMS) to detect hydrogen leakage. Install Offgas calibration gas supply tubing, valves, and interconnecting wiring, conduit, and pull boxes.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Heater Drains and Vents DCN 51116	Replace six tube side heater relief valves and modify piping such that valve inlets are mounted in the vertical direction. (Note: DCN 51464 replaces the associated shell side heater relief valves.) Replace six heater level control valves including operators, positioners, and pressure regulators to prevent unacceptable modulation of water levels (1-LCV-6-11A, -29A, -47A, -14A, -32A, -50A). Replace Number 3 Feedwater heater level control valves with valves that do not incorporate a fluid-filled stem snubber (1-LCV-6-7, -25, & -43). [EPU: Replace 4-inch moisture separator level control valves with 6-inch valves and new operators and positioners (1-LCV-6-62A, -62B, -73A, -73B, -84A, -84B). Expansion joints (bellows) in the No. 2, 3, 4, and 5 extraction steam piping located inside the condenser are being replaced with stainless steel expansion joints to address flow-accelerated corrosion]. Replace level control valves including actuators and positioners (1-LCV-6-1, -19, -37, -4A, -4B, -22A, -22B, -40A, -40B, -11B, -29B, -47B, -14B, -32B, -50B). Replace 4-inch moisture separator level bypass to condenser level control valves with 6-inch valves and new operators, local positioners, and limit switches (1-LCV-6-61A, -61B, -72A, -72B, -83A, -83B). Replace packing for various valve stems with graphite ring packing as described in EPRI Report NP-5967.	Y
Heater Drains and Vents DCN 51139	Provide for refurbishment of Reactor Feedwater heaters as follows: Addition of electronic level switches, addition of control cables from level switches to the associated heater extraction isolation valve, and addition of associated level transmitters. Existing glass level gauges are replaced with all metal gauges and test valves are added. Root valves and their instrument level piping from their connection points on respective heaters are replaced with stainless steel components. Replace existing condensate chambers with new chambers possessing approximately five times greater volume than presently installed chambers capacities.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Control Bay Panels DCN 51094 DCN 51095 DCN 51096 DCN 51097 DCN 51098 DCN 51099 DCN 51100 DCN 51101 DCN 51103 DCN 51104 DCN 51105 DCN 51106 DCN 51108 DCN 51109 DCN 51077 DCN 51111	Summary of changes to PNLs 1-9-3, -4,:-5, -6, -7, -8, -10, -18, -19, -20, -21, -22, -32, -33, -47, -53, -54, -55, 1-25-32 to resolve Control Room Design Review (CRDR) issues: Multiple component relocations within, to, and from other Control Room panels. Multiple indicator replacements as a result of loop signal changes and indicator obsolescence. Multiple indicating scale modifications to adhere to Human Engineering Standards. Installation of new component labels and switch escutcheon plates. Installation of new system mimics. Panel surface enhancements. Replacement of obsolete recorders with Westronics digital paperless recorders. Replacement of the HPCI and RCIC controllers and power supplies. Relocation of the Acoustic Monitoring System from panel 1-9-47 to panel 1-9-3. Installation of the Containment Isolation Status System (CISS) initiation and success indicators. Replacement of Recirculation Pump speed indicators with grouped pushbuttons and status lamps. Replacement of handswitches associated with the lube oil pumps that control Recirculation Drive Cooling Pumps. Replacement and recalibration of Condensate Pump and Condensate Booster Pump monitoring instrumentation. Delete redundant U2 and U3 electrical distribution controls that do not support Unit 1 operations. Installation of a new fiber optic Local Area Network (LAN) throughout the Main Control Room (MCR), connecting all MCR process recorders to a recorder host PC. Install controls and indication to support the new Hydrogen Water Chemistry system. Relocate all System 02, Condensate and Demineralized Water, (Condensate Storage and Transfer portion) controls, indicators, and meters from panel 1-9-20 to panel 1-9-22. Provide new indication for Fire Protection Header Pressure. Remove Circulating Water Traveling Screen Speed Indications. Provide new Standby Gas Treatment outlet flow indication. Remove Standby Gas Treatment Train operability indication. Deletion of IRM, APRM, RBM, & SRM selector switches. Removal of the annunciation for the Rod Sequence Control System. Removal of Core Spray System Testable check valves, indications, and controls. Removal of Residual Heat Removal (RHR) System Testable check valves, indications, and controls. Removal of the Primary Containment Isolation System (PCIS) Group 7, HPCI and RCIC valve indication from the PCIS mimic. Installation of equipment associated with the Hardened Wetwell Vent modification. Support activities for the annunciators, Common Accident Signal (CAS), and Unit 2 CAS. Upgrade analog flow controllers to digital loop controllers (1-FIC-84-19 & -20). Remove, replace, relocate, abandon power supplies and flow instrumentation for RHR, Core Spray, and RHR Service Water.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Boiler Drains and Vents DCN 51065	Provide modifications for the Main Steam Relief Valve discharge piping located in the drywell from the (13) MSRVs to the impingement barrier. Replace existing mechanical snubbers with new mechanical snubbers.	Y
Boiler Drains and Vents DCN 51067	Provide additions and modifications to the supports for the Reactor Head Vent and Reactor Bottom Head Drain piping located in the drywell. Provide for the addition of one new snubber to the Reactor Head Vent piping.	Y
Boiler Drains and Vents DCN 51144	Remove RPV low point drain valves (1-10-503, -504) and associated piping. Replace existing RPV drain line isolation globe valve (1-10-505) with a gate valve. Replace existing RPV head vent drain globe valves (1-10-500, -501, -502) due to obsolescence and leak potential. Replace some sections of RPV head vent piping with new piping of upgraded material and schedule to reduce pipe stresses and minimize the number of pipe supports. Upgrade Main Steam Relief Valve (MSRV) discharge pipe 10-inch vacuum breaker valves.	Y
Central Lube Oil DCN 51117	Install unit isolation valves between Unit 1 and the common header for all three units, including the new crossover line between Unit 1 supply and return headers, and reconnect Unit 1 piping to the common plant purifier header piping. Modify, replace, or add equipment, electrical components, foundations, and piping within the Central Lube Oil System and 480 V Turbine Building Vent Board System to support a new Unit 1 Turbo TOC purifier. Modify High Pressure Fire Protection System to add coverage for the new Turbo TOC.	Y
RHR Service Water DCN 51177	Install replacement equivalent thermocouple assemblies (1-TE-23-32, -35, -38, -41, -44, -47, -50, & -53) in existing thermowells (1-TW-23-32, -35, -38, -41, -44, -47, -50, & -53) respectively. Install new thermowells 1-TW-23-4100 & -4101 and new Resistance Temperature Detectors (RTDs) 1-TE-23-4100 & -4101 to accommodate temperature measurement on the outlet side of the heat exchangers. [EPU: Replace RHRSW Flow Control Valves (1-FCV-23-34, -40, -46, & -52) and their associated Motor Operators (1-MVOP-23-34, -40, -46, & -52)]. Replace relief valves on inlet and outlet of heat exchangers (1-RFV-23-509, -516, -529, -536, -549, -555, -568, & -574). Rework and upgrade Dresser couplings for A and C lines in the Service Water Tunnel. Revise large bore pipe supports for Loops A and C to meet current design requirements including EPU.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Raw Cooling Water DCN 51118	Install two (2-inch) injection lines to allow connection to the U2/U3 skid for chemical injection to the 42-inch Raw Cooling Water (RCW) Supply Header. Replace 1-TCV-24-40 existing 8-inch gate valve with an 8-inch globe valve of stainless steel and reroute control air piping to valve as necessary. Revise setpoints for RFPT bearing lube oil temperature controllers to allow operators to determine setpoint as process dictates. Upgrade 1-TCV-24-75 and install a bypass line for low-flow operation. Replace Stator Cooler outlet valves (1-THV-24-620A, & -620B) with stainless steel valves and replace associated downstream 8-inch piping with stainless steel pipe. Replace Henry Pratt butterfly RCW header isolation valves (1-24-523) 24-inch; and (1-24-534) 10-inch, with Flowserve butterfly valves. Perform underwater repairs on leaking return piping to Wheeler Reservoir. Revise RCW supply and return piping to Condensate Booster Pump area coolers. Refurbish instrument piping in Panels 1-25-178, -179, -182, & -182.	Y
Raw Cooling Water DCN 51178	Eliminate 2-inch RCW supply to H2-O2 Analyzer Panels 1-25-340 & -341. Remove piping, cut and cap just after valve 1-24-882 (2-inch). Install new thermowells 1-TW-24-80, -85, & -90 in Reactor Building Closed Cooling Water (RBCCW) heat exchanger 1A, 1B, & 1C outlets and replace thermocouples. Eliminate RCW supply to RHR Pump Seals and Room Coolers. Eliminate RCW supply to Control Bay Chillers.	Y
Raw Cooling Water DCN 51189	Replace and up size RCW piping, components, and supports to new Drywell Delta P Compressor.	Y
Raw Cooling Water DCN 51219	Installation of RCW supply/return piping to/from each Reactor Recirculation Pump Variable Frequency Drive (VFD) heat exchanger, associated flow and temperature instrumentation, cabling/conduit and supports.	Y
Raw Service Water DCN 51120	Replace existing pairs of CUNO filters with redundant abrasive separators and rough duplex strainers for the Raw Service Water supply to the Condenser Circulating Water (CCW) pump bearings.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
High Pressure Fire Protection and Detection DCN 51180	Replace HPCI Turbine room deluge valve 1-FCV-26-37 with a packaged pre-action valve station. Modify Reactor Building existing pre-action sprinkler system on floor elevations 565', 593', 621', and south half of 639' to achieve area wide coverage. Install pre-action water curtain at the equipment hatch openings between Elevation 565' and 639' at column line R5/R6-T/U. Install pre-action sprinkler water curtain at the RHR Heat Exchanger door openings at Elevation 565'. Install pre-action sprinkler water curtain in the openings in east and west RHR Heat Exchanger rooms on the ceiling immediately below floor Elevation 565'. Install pre-action sprinkler water curtain at the stair openings between Elevation 565' and 639' at column line R1-U. Install pre-action sprinklers beneath stair landings in the southwest stairway at Elevation 605 and 630. Remove the existing fixed-water spray systems on Elevation 565' and 593'. Remove and discard all components of the Aqueous Film Forming Foam (AFFF) system.	Y
Condenser Circulating Water DCN 51120	Design, procure, and install a debris filter for the inlet piping/water box for the Unit 1, C2 water box. Relocate the existing Nash vacuum priming valves and tie-in to the 4-inch water box vent piping. Replace sponge ball recirculation pumps with new pumps of 316SS wetted parts. Replace the collector inlet ball valves and associated motor operators. Replace collector discharge ball valves. Replace existing motor operators on the upper screen and lower screen of the strainer section in the tube cleaning system. Delete Control Air supply to the differential pressure indicating switches in the Amertap ball collection system. Modify valve operator circuitry for Vacuum Breaker valves (1-FCV-27-118A & -118B). Replace existing cables from each CCW pump to its associated capacitor bank. Revise the alarm circuitry for condenser water box level instrument loops (6). Evaluate operation of CCW system at EPU conditions.	Y
Condenser Circulating Water DCN 62015	Replace Cooling Tower No. 4.	Y (Common)
Ventilation DCN 51748	Facilitate the parallel operation of existing redundant air handling units (AHUs), on an as-needed basis, for the Condensate and Condensate Booster Pumps Area Ventilation System in support of EPU. Provide supplemental cooling to the new Hydrogen Water Chemistry (HWC) panel.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Control Air DCN 51122	Install an automatic actuated Unit isolation pressure control valve station on the Turbine Building between Unit 1 and Unit 2 to allow isolation of a leaking portion of the header in Unit 1 from the remainder of the system. Replace Secondary Containment Isolation Valves (1-FCV-32-28 & -29) and rewire associated solenoid valves (1-FSV-32-28A & -29A). Install manual isolation valves to future use with new Hydrogen Water Chemistry (HWC) panels in Turbine Building.	Y
Control Air DCN 51164	Replace pressure switches monitoring control air pressure to the Automatic Depressurization System (ADS) MSRVs (1-PS-32-31A thru -31F). Relocate ADS MSRV accumulators, re-size inlet and outlet lines, and re-route inlet line to top of the accumulator. Balance Control Air distribution between the two Drywell Control Air (DCA) header segments. Determine acceptable leak rate through check valves at the accumulator assemblies for the ADS MSRVs and MSIVs.	Y
Control Air DCN 51182	Delete Drywell Control Air Compressors A and B, and related aftercoolers, surge tanks, dryers, control instruments, piping, valves, and cables. Replace existing Drywell Control Air Receiver Tank Pressure switch (PS-32-70) with a non-mercury filled switch. Provide a source of nitrogen to the DCA system from a 1-inch Containment Inerting System branch connection at check valve (1-CKV-76-542). Nitrogen is regulated to 100 psig by a new DCA pressure regulator station on panel (925-0700). Remove Drywell Control Air prefilter and associated piping and instrumentation. Replace Primary Containment Isolation Valves (1-SHV-32-2160, & -2520 and 1-CKV-32-336 & -2521). Remove Primary Containment Isolation flow control Valves (1-FCV-32-62 & -63).	Y
Service Air DCN 51183	Remove all Service Air piping from the drywell. Piping to be cut between Penetration X-21 and check valve (33-785). Install air supervision system for piping downstream of valve (FCV-26-77). Air supervision supply will connect to existing Service Air header on Elev. 565'. Change Control Air Shutoff valve (1-SHV-32-1469) from Normally Open to Normally Closed. Cut associated line, plug, and label connection as "Spare".	Y
Sampling and Water Quality DCN 51126	Install a permanent tee and sample valve (1-SMV-43-852) in the generator breaker (1-PCBC-35-214) cooling water line to allow for sampling of the demineralized water, to verify proper conductivity. Provide seismically rugged anchors for the Main Steam Sample Station constant temperature bath. Replace generator breaker (1-PCBC-35-214) cooling water conductivity instruments with equivalent models, as was done on Units 2 and 3, in the water cooling plant (1-CLR-35-797).	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Sampling and Water Quality DCN 51140	Replace existing obsolete Generator Cooling Water Conductivity Cells (1-CE-43-16A, -16B, -16C) and associated transmitters (1-CIT-43-16A, -16B, -16C). Add sample test connections at same locations as conductivity elements to enable calibration. Add new oxygen analyzers (1-O2AN-43-12, & -13) using dp across the inlet and outlet of the Stator Cooling Water System Deionizer to drive flow.	Y
Sampling and Water Quality DCN 51168	Replace (1-FSV-43-13) due to age, time in harsh environment, and degraded components. Replacement valve to have stem seal packing which meets EPRI guidelines. Associated switches (1-ZS-43-13A and -13B) are being replaced. Existing globe valves (1-ISV-43-599, 1-TV-43-1054A and -1054B) with gate valves for enhanced performance and replacement valves to have stem seal packing which meets EPRI guidelines. Delete existing vent line from the Reactor Recirculation discharge piping to sampling and associated valves (1-43-812A, & -812B) which serve no design function. Rework instrument sensing lines for flow elements (1-FE-71-1A & -1B) to correct negative slope and provide accurate steam flow indication and line break detection.	Y
Sampling and Water Quality DCN 51478	Replace and relocate instrumentation from the Condensate Demineralizer Sampling Panel (25-148) to the Condensate Sample Panel (25-103). Add oxygen and hydrogen analyzers (1-O2AN-43-9 and 1-H2AN-43-9, respectively) to the new Condensate Sample Panel. Add a sample chiller unit (1-CHR-43-2060() to cool influent sample streams in support of new panel (25-103). Add a Feedwater roughing cooler (1-CLR-43-4B). Provide data feed from new panel (25-103) to the Integrated Computer System (ICS) See DCNs 51082 and 51137. Reroute ducts to provide exhaust capability for sample sink in new panel (25-103). Delete existing Feedwater turbidity instruments from panel (25-149).	Y
Feedwater Level Control DCN 51138	Replace existing Reactor Feed Pump Turbines (RFPT) governor control, lubricating and control oil, vibration monitoring, and trip components in conjunction with the addition of a Foxboro Digital Reactor Feedwater Control System (DRFWCS). Install new panel 9-97 in the MCR and add fiber optic cables from Aux Instrument room and Unit 1 Computer room to two local panels (925-562A & 925-562D). Remove existing RFPT controls including the mechanical linkage, Motor Speed Changer (MSC), and Motor Governor Unit (MGU); and replace with a Woodward Digital Governor and Final Drive.	Y
Standby Liquid Control DCN 51081	Modify loop (1-P-63-7) power supply from 10-50 mA to 4-20 mA in panel (1-9-19).	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Standby Liquid Control DCN 51166	Replace cable and conduit for SLC drywell inboard isolation valve zone switch.	Y
Standby Liquid Control DCN 51233	Modify/replace RTDs (1-TE-63-3 and -4) to upgrade obsolete equipment and ensure monitoring of tank solution instead of area ambient temperature. Replace (1-PI-63-7B and 1-PT-63-7) to remove obsolete equipment and add isolation valve, drain valve (1-ISIV-63-7BA and -7BB) and quick disconnect to facilitate calibration. Remove heat tracing from process lines and components in the SLC system. Replace and rescale temperature switches (1-TS-63-3 and -4) to comply with 10CFR50.62 ATWS equivalency requirements for B10 enriched sodium pentaborate. Revise SLC Storage Tank level alarm setpoints to support implementation of Alternate Source Term and associated Tech Spec change which increases the net injectable volume of sodium pentaborate from 3007 to 4000 gallons.	Y
Reactor Building Ventilation & PCIS DCN 51081	Provide for modification of Primary Containment Isolation System (PCIS) cabling from panel (1-9-15) to panels (1-9-42 and -43) to provide functional redundancy separation. Existing power supply (1-PX-74-51) feeding loops (1-L-64-159A and 1-P-64-160A) and new RTD temperature modifier (1-TM-64-52CA) are rewired to be segregated and powered from panel (1-9-42). In panel (1-9-19) modify loop (1-P-64-67) for conversion from 10-50 mA to 4-20 mA. Modify pressure switches (1-PDS-64-137A, B, C and 1-PDS-64-138A, B, and C) wiring to allow one loop to be removed from service without affecting the redundant loop.	Y
Reactor Building Ventilation & PCIS DCN 51166	Replace obsolete inboard Drywell Personnel Air Lock limit switch (1-ZS-64-53A), associated cable, and conduit. Replace Drywell Air Temperature elements (1-TE-64-52A & -52C) from thermocouples to RTDs and replace associated cable, conduit, and conduit seals. Delete the following Drywell Leak Rate instruments, associated cables and conduit: temperature elements (1-TE-64-82 thru -99) (18 total); humidity sensors (1-ME-64-111 thru -114) (4 total); and pressure sensor (1-PT-64-115) (1 total). Fabricate and install new Unit 1 Drywell Primary Containment Equipment Hatch Cover Lugs.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Building Ventilation & PCIS DCN 51189	Provide for modification of Drywell Vacuum Breakers (1-FCV-64-28A, thru 28M [except 28I]) by replacing hinge arms, hinge pins, bushings, and other parts per (NUREG-0661). Install Unit 1 Torus vent path to the common header portion of the Hardened Wet Well Vent (HWWV), including Primary Containment Isolation Valves (PCIVs) (1-FCV-64-221, & -222) and associated solenoid valves, air operators, 250V dc power, and Control Room handswitches and indications. Replace the following unqualified valves with 10CFR50.49 qualified models: (1-FSV-64-17, -18, -19, -20, -21, -29, -30, -31, -32, -33, & -34). Replace the following valves, including Bettis actuators (1-FCV-64-17 thru -21; -29, -30; 32, & -33) with new valves having closing times of 2.5 seconds or less. Replace cables/conduits, limit switches, terminal blocks, and other electrical components to satisfy EQ, Class 1E, and ampacity issues, and to resolve component reliability issues due to age, time in harsh environment, and degradation. Replace previously removed Drywell Delta P compressor, motor, aftercooler, and associated controls and cables/conduit. Replace two unqualified Drywell Penetrations (PA), containing airlock lighting, telephone, and door status circuitry, with (1) ASME Section III qualified penetration assembly.	Y
Reactor Building Ventilation & PCIS DCN 51190	Provide for fire damper installation in Reactor Building Ventilation ducts through floor penetrations (27 dampers). Provide for new Main Steam Vault Exhaust Booster Fan installation. Provide for replacement of Core Spray and RHR Pump Room Cooler motors, EQ associated cables, and room temperature instruments. Provide for replacement of Secondary Containment Isolation Valve cables, limit switches, and terminal blocks.	Y
Reactor Building Ventilation & PCIS DCN 51243	Modify/add/replace components and wiring internal to Emergency Core Cooling System (ECCS) Panel (1-9-81). Modify/add/replace components and wiring internal to ECCS Panel (1-9-82). Modify/add/replace components and wiring internal to Reactor Protection System (RPS) Panel (1-9-83). Modify/add/replace components and wiring internal to RPS Panel (1-9-84). Modify/add/replace components and wiring internal to RPS Panel (1-9-85). Modify/add/replace components and wiring internal to RPS Panel (1-9-86). Refurbish components and cabling to Panels (1-25-5A, -5B, -5C, -5D, -6A, -6B, -6C) and replace EQ cables. Refurbish components and cabling in Panels (1-25-31, -34, -57B, -57D, -213, -219, -220, -221, -222, -306, -307, and -308) and replace EQ cables.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Building Ventilation & PCIS DCN 51245	Replace torus wide range level transmitters (1-LT-64-159A & -159B), install quick-disconnect fittings, and splices. Replace torus narrow range level transmitters (1-LT-64-54 & -66) and associated flow controllers (1-FIC-64-54, & -66). Add level sensors (1-LE-64-54, & -66); sight glasses (1-LG-64-54, & -66) demineralized water connections, platforms, communications, lighting, and power.	Y
Reactor Building Ventilation & PCIS DCN 51318	Remove removable relief panels in Unit 1 to combine four Secondary Containment zones into one zone. One result of this change is the free flow of each reactor zone atmosphere with the common refuel floor atmosphere. For Elev. 639', 621', & 593', remove all vertical removable relief panels and steel frames surrounding the equipment hatch. Install removable handrails around the hatch. The handrails are Seismic Class II/I (position retention). For Elev. 593' to 580', remove all removable relief panels, however, steel frames are left in place. For Elev. 580' to 565', remove all vertical removable panels and vertical steel frames surrounding the truck bay. Remove horizontal roof panels, however, beams and steel frames are left in place. Add three new diagonal braces to the roof steel platform. Seal two (2) 4-inch Dirty Radwaste (DRW) floor drains with removable closure plates to prevent the flow of water from the SE corner of the Rector Building into the HPCI room. Provide for the installation of an 8-inch concrete curb and ramp in the labyrinth passage of the Main Steam Valve Vault (MSVV) to contain water within the vault. Provide for increasing the concrete curb at the entrance to the HPCI room from 12 inches to 18 inches to prevent water from entering the room.	Y
OffGas DCN 51128	Replace existing obsolete Catalytic Recombiner drain valves (1-FSV-66-73, & -88). Install test connections in suction and discharge piping of Vacuum Pumps (1-PMP-66-43A1, & -43B1) to support Condenser air inleakage tests. Install spring-operated piston check valves (1-CKV-66-922, & -923, respectively) on Service Air System connected to Offgas System Train 'A' and 'B', respectively. Replace SJAE inlet and outlet valves (1-FCV-66-11, -14, -15, & -18) with spark-proof seats. Modify Offgas sample connections to H2 & O2 analyzer containing valves (1-SHV-66-575, & -576). Add Chilled Water sample line at (1-PI-66-63). Replace Chilled Water relief valve (1-RFV-66-541). Replace Glycol Recirculation Pumps (1-PMP-66-104, & -105). Replace Offgas Stack discharge valve (1-FCV-66-28) with spark-proof seat and replace associated solenoid (1-FSV-66-28) and limit switches (1-ZS-66-28A, & -28B).	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
OffGas DCN 51142	Modify/upgrade Offgas flow to 6-hour holdup volume loops (1-F-66-111A & -111B): Relocate flow elements (1-FE-66-111A, & -111B) downstream of dehumidifiers to reduce moisture problems and replace with a Kurz combo FE/FT. Remove existing flow transmitters (1-FE-66-111A, & -111B) from panel 25-95. Add blind flanges where previous flow elements were located. Add two Kurz Instrument flow computers to replace existing (1-FI-66-111A, & -111B; 1-FX-66-111A, & -111B; 1-FM-66-111A, & -111B; 1-FS-66-111A, & -111B). Remove GE indicators (1-FIS-66-111A, & -111B) from panel 25-95. Add time delay relay (1-RLY-66-111) on panel 25-95. Upgrade Offgas flow to 6-hour holdup volume loop (1-F-66-20): Replace Fisher and Porter flow indicating transmitter (1-FIT-66-20) with a Rosemount transmitter connecting to the existing sensing lines from (1-FE-66-20) and providing a linear signal to (1-FR-66-20) on panel 9-8, negating the need for (1-FM-66-20). Remove (1-FM-66-20) from panel 9-29 and re-label (1-FT-66-20 to 1-FIT-66-20). Modify/upgrade Offgas Condensed level control loops (1-L-66-93, & -94): Replace existing 10-50 mA transmitters (1-LT-66-93, & -94) with 4-20 mA transmitters on panel 25-335. Replace existing 10-50 mA controllers (1-LIC-66-93, & -94) with 4-20 mA controllers on panel 25-95 that will also power the loops. Replace existing (two) 10-50 mA level switches (1-LS-66-93, & -94) with (four) 4-20 mA level switches (1-LS-66-93A, -93B, -94A, & -94B) on panel 25-95. Replace existing 10-50 mA I/Ps (1-LM-66-93, & -94) with 4-20 mA I/Ps located in the Recombiner Room. Remove existing power supply (1-PX-66-93). Provide standby level loop (94) with its own independent power by feeding power to (1-LIC-66-94) from non-preferred 120V ac from panel 9-9, BKR 522. Add new panel 25-96A. Modify Glycol Tank temperature loop (1-T-66-102) with programmable logic controller (1-TC-66-102) on new panel 25-96A. Modify Offgas Reheater Outlet Moisture Loop (1-M-66-110) to be an offline system with capability to be isolated from the Offgas system without isolating the Offgas system which it monitors. Modify Offgas Condenser outlet temperature loop (1-T-66-95) for higher temperature range (from 155 to 160 deg. F). Replace Offgas Recombiners A & B temperature controllers (1-TC-66-76, & -90). Revise setpoints: 6-hour holdup volume pressure switches (1-PIS-66-21C, & -21D) to 3.5 psig increasing. CNDR vacuum pump seal water temperature switches (1-TS-66-55, & -56) from 110 deg. F to 120 deg. F CNDR vacuum pumps 1A & 1B suction pressure switches (1-PS-66-37, & -41, respectively, from 27" Hg to 26" Hg.	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Emergency Equipment Cooling Water DCN 51192	Replace the following carbon steel valves with stainless steel valves: (1-Ckv-67-541, -542, -554, -584, -585,-597, -648, -649, -656, -657, & -598) (1-TV-67-236, -237, -243, -244, -251, -252, & -259) (1-SHV-67-550, -551, -569, -570, -593, -594, -596, -610, & -611) (1-VTV-67-746, & -751). Reroute 1-inch Emergency Equipment Cooling Water (EECW) line to H2 Analyzers that interferes with a permanent ladder required for access to (1-FCV-23-57) during performance of certain Emergency Operating Instruction appendices. Add EECW 1-inch flush connections with piping, shut off valves, and quick disconnects to the supply and discharge lines for RHR Pump Room Coolers 1A, 1B, 1C, & 1D. Add the following 1-inch valves at the flush connections: (1-SHV-67-817 & -818) at RHR Room Cooler 1A return and inlet connections, respectively; (1-SHV-67-827 & -828) at RHR Room Cooler 1B return and inlet connections, respectively; (1-SHV-67-819 & -820) at RHR Room Cooler 1C return and inlet connections, respectively; and (1-SHV-67-829 & -830) at RHR Room Cooler 1D return and inlet connections, respectively. Change motive fluid for valves (1-FCV-67-50 & 51) from water to air. Cut, remove and cap piping downstream of valves (1-RTV-67-6022A & -6009A) and up to the connection to the valve operators for (1-FCV-67-50 & -51) respectively. Provide new ½-inch connections to install pressure switches (1-PS-67-50 & -51) in the 8-inch header at the downstream side of valves (1-SHV-67-640 & -575) respectively. Add a travel stop to valve (1-FCV-67-50) to limit travel to 25%, +/-1% of maximum opening.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Water Recirculation DCN 51016	Modify the existing RHR Low Pressure Coolant Injection (LPCI) System signal isolation of the Recirculation Pump discharge valve logic so that the Div I RHR (LPCI) signal will only isolate the 1B Recirculation Pump discharge valve associated with the LPCI loop I injection line, while the Div II RHR (LPCI) signal will only isolate the 1A Recirculation Pump discharge valve associated with the LPCI loop II injection line. Delete the interlock signals from pressure switches (1-PS-68-93, & -94) to block the isolation of the LPCI injection valves (1-FCV-74-53, & -67) on a Group 2 PCIS initiation when reactor pressure is ≥105 psig. Pressure switches (1-PS-68-93, & -94) will continue to provide a (reactor pressure ≥105 psig) signal to relays (10A-K97A & 10A-AK97B) to isolation valve (1-FCV-74-48) which prevents shutdown cooling from being in service when reactor pressure is ≥105 psig. Modify Core Spray initiation & ECCS Preferred Pump logic so that U2 Core Spray (CS) Pumps 2A & 2C and Residual Heat Removal (RHR) Pumps 2A & 2C are load shed on a U1 accident signal initiation and U1 CS Pumps 1B & 1D and RHR Pumps 1B & 1D are load shed on a U2 initiating signal if the pumps were running with normal power available. Thus, CS Pumps 1A & 1C and RHR Pumps 1A & 1C are dedicated to U1 and CS Pumps 2B & 2D and RHR Pumps 2B & 2D are dedicated to U2 with either normal or DG power available. Add new load shed initiating signal from CS Relays (14A-K11A & -K11B) which will be redundant to Relays (10A-K73A & -K73B) to avoid single failure and overloading of (2) 4kV Shutdown Boards.	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Water Recirculation DCN 51045	Replace existing Reactor Pressure Vessel (RPV) recirculation outlet safe ends at nozzles N1A and N1B (total of 2) with those made of 316NG stainless steel. Replace existing (RPV) recirculation inlet safe ends at nozzles N2A, N2B, N2C, N2D, N2E, N2F, N2G, N2H, N2J, & N2K (total of 10) with those made of 316NG stainless steel. Remove and replace the existing 28-inch recirculation lines between the RPV recirculation safe end to the RPV recirculation ring headers, including flow elements for loops A & B, with those made of 316NG stainless steel. Remove and replace the existing recirculation risers (total of 10) at RPV nozzles N2A, N2B, N2C, N2D, N2E, N2F, N2G, N2H, N2J, & N2K, with those made of 316NG stainless steel. Remove and replace the existing ring headers in the pump discharge piping for loops A & B, with those made of 316NG stainless steel. Remove valves (1-FCV-68-33 & -35) and associated circuitry and controls inside the Drywell. Remove associated valves (1-68-530, -531, -532, -533, -535, -536, -537, -538, -68-NNN-1, &-68-NNN-2) and the 22-inch piping between loop A & B ring headers. Remove and replace existing Jet Pump Instrumentation (JPI) nozzle safe ends at RPV nozzles N8A & N8B, and proximity piping. Delete valves (1-68-292, -293, -294, & -295). Remove (8) 1-inch sensing lines installed between recirculation discharge risers at RPV nozzles N2A - N2H, and N2J, N2K and their associated containment penetrations. Cut and cap the penetrations. Replace the following thermowell/temperature element sets: (1-TW-68-2 & 1-TE-68-2; 1-TW-68-6 & 1-TE-68-6A & 1-TE-68-6B; 1-TW-68-78 & 1-TE-68-78; 1-TW-68-83 & 1-TE-68-83A & 1-TE-68-83B). Remove and cap the bonnet vent lines for valves (1-FCV-68-1, -77, & -79) and remove associated drain valves (1-68-502, -503, -511, -512, -517, -518, -526, -527). Add (3) new vent valves and piping routed to Clean Radwaste for each Recirculation Pump (valves 1-68-6601, -6602 & -6603 for pump 1A & 1-68-6604, -6605, & -6606 for pump 1B). Provide permanent radiation shielding (lead blankets) for vertical segments of the 12-inch and 28-inch recirculation piping. Replace 2-inch globe valves (1-68-505, -506, -520, & -521) in recirculation pump suction drain lines with valves of non-cobalt trim and EPRI-approved graphite packing. Replace rotating assemblies and seal cartridges for recirculation pumps (1-PMP-68-60A & -60B) including shafts, seals, impellers, and covers. Replace recirculation pump seal injection lines and associated valves.	Y
Reactor Water Recirculation DCN 51167	Replace existing Recirculation Pump/motor 1A & 1B vibration monitoring and speed indicating instrumentation, cabling and conduit. Refurbish and rewind recirculation pump motors.	Y
Reactor Water Recirculation DCN 51178	Provide Raw Cooling Water to Variable Frequency Drives (VFDs) which replace M-G sets (DCN 51219) for Recirculation Pump motors.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Water Recirculation DCN 51193	Replace existing inner and outer RPV head metallic O-ring seals with new spring-energized O-rings and associated retainer clips. Repair Intergranular Stress Corrosion Cracking (IGSCC) on and around the two Access Hole Covers (AHCs) in the RPV shroud support plate, to include installation of new AHCs if necessary. Install retaining clamps on jet pump instrument sensing lines (internal to the RPV) to resolve vibration issue. Replace the (48) shroud head bolts with newly designed bolts. Replace RPV core plate plugs as required. Replace the following Recirculation Pump seal injection line valves:; (1-CKV-68-550 & -555; 1-SHV-68-552 & -557; 1-VTV -68-551 & -556; and 1-RFV-68-553 & -558). Relocate flow indicators (1-FI-85-52, & -53) to downstream of the inlet connections of seal injection supply relief valves to provide a more accurate indication of seal injection flow to the Recirculation Pumps.	Y
Reactor Water Recirculation DCN 51218	Replace cables identified for replacement in Total Program Breakage Summary. Splice Reactor Water Recirculation System circuits on outboard (reactor building) side of Penetrations (EB, EC, & EE). Abandon/remove cables for components that are deleted. Determ/splice/reterm cables not replaced but requiring wiring changes. Modify breaker compartments, components, and panel wiring for power and control circuits of MOVs (1-FCV-68-3, -33, -35, & -79).	Y
Reactor Water Recirculation DCN 51219	Abandon M-G sets powering Recirculation Pump motors (in -place) and install new solid state Variable Frequency Drives (VFDs). Remove M-G set lube oil skids, heat exchangers, and foundations. Rerate Recirculation Pump motors from 8000 to 8550 hp.	Y
Reactor Water Recirculation DCN 51234	Install new panel (1-LPNL-925-412), vibration monitoring system, associated cables, and system panel to support EPU. Refurbish existing Reactor Water Recirculation System instrument panels/racks (1-25-7A, -7B, -51B, -52A, -52B, & 1-9-18). Replace existing GE Measurement & Control components with Foxboro Intelligent Automation (I/A) components. Refurbish existing affected panels (1-9-38, -18, & -19). Complete implementation of Recirculation Pump Trip (RPT) and portions of the (ATWS) modifications for Unit 1. Affected panels are (1-925-416, -612, -415, -613, -614, -616, -615, & -419). Perform Foxboro and Bentley-Nevada software verification and validation.	Y
Reactor Water Recirculation DCN 60072	Install control circuit isolation fuses in the positive legs of the 250 V dc trip circuits for Normal; and Emergency feeder breakers for Reactor Recirculation Pumps 1A (Breakers 1122 & 1436) and Pump 1B (Breakers 1124 & 1534). Also, a single fuse is added to the positive leg in the 250 V dc circuits for Reactor Recirculation Pumps 1A & 1B Overcurrent Relay and Transfer Selector Switch circuit (Appendix R).	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Water Cleanup DCN 51046	Remove and replace 6-inch process piping and valves from the 20-inch RHR piping connection to primary containment penetration X-14. Replace Motor Operated Valves (1-FCV-69-1, & -2) per TVA's GL 89-10 program and add valves/capability for Appendix J testing of (1-FCV-69-1). Replace system valves inside the Drywell (1-69-500, -583, -584, -503, & -504). Install a 2-inch decontamination flush connection with 2-inch gate valves (1-69-551, & -552) and a camlock male fitting. Replace cable to (1-FCV-69-1) to correct ampacity/voltage concerns and install (2) T-drains. Install instrument locations to measure piping vibration.	Y
Reactor Water Cleanup DCN 51194	Replace/upgrade various 4-inch and 6-inch piping segments to, from, and interconnecting regen and non-regen heat exchangers and from RWCU pump discharge to the tie-in to the RWCU demineralizer influent pipe. Replace regenerative heat exchangers. Replace RWCU recirculation pumps (1-PMP-69-4A, & -4B). Replace small bore vent, drain, and test connections branching off of the RWCU piping, including the associated valves. Replace instrument lines branching from replaced piping, up to the root valves. Replace flow elements on RWCU discharge lines. Replace various thermowells and temperature elements. Replace strainers (1-STN-69-800 & -801). Reroute RWCU flow from outboard isolation valve (1-FCV-69-2) through regenerative heat exchangers A, B, & C, and non-regenerative heat exchangers A & B, the to the RWCU Pump suction resulting in lower temperature water entering pumps and longer lasting pump seals.	Y
Reactor Building Closed Cooling Water DCN 50977	Complete the piping tie-in to the Unit 1 Reactor Building Closed Cooling Water (RBCCW) System from the existing Drywell Outage Chillers.	Y
Reactor Building Closed Cooling Water DCN 51148	Replace RBCCW System carbon steel piping within the drywell with stainless steel piping. Replace the drywell atmosphere cooling coils and blowers (Drywell Cooler) to improve cooling of drywell atmosphere. Replace the inlet and outlet RBCCW valves to each of (10) coils. Upsize Drywell Cooler blower motor power cables (See DCN 51195). Delete (60) cables, associated conduits and junction boxes due to new Drywell Coolers being completely factory wired. Modify RBCCW piping to new Recirculation Pump seal assemblies and reduce connections to one supply and one return per seal assembly cooler. Replace (44) cables inside the drywell with environmentally qualified (EQ) cables.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Building Closed Cooling Water DCN 51195	Install isolation, drain, and test valves to provide for LLRT of Primary Containment Isolation Valves (1-CKV-70-506 & 1-FCV-70-47). Replace thermowells and temperature elements for loops (1-T-70-3, -50, -51, -52, -53, -54, -56, -58, & -60). Document thrust requirements and switch settings for motor operated containment isolation valve (1-FCV-70-47) to meet GL 89-10 requirements.	Y
Reactor Core Isolation Cooling DCN 51149	Replace solid wedge gate valve (1-FCV-71-2) with a newer design double disc gate valve. Delete the associated leak-off valve and piping. Add a ¾" test line to bottom of new valve body for between-seat leak testing. Install new motor operator to meet EQ and GL 89-10 requirements. Replace existing cable, conduit, and conduit supports for this new MOV and bypass the torque switch in the motor operator control circuit.	Y
Reactor Core Isolation Cooling DCN 51196	Perform various mechanical modifications to the Reactor Core Isolation Cooling (RCIC) System valves from among the following: Upgrade valve packing to EPRI-approved graphite (live-load) packing, remove leak-off valves, cut, and cap or plug, leak-off lines. Replace solid wedge gate valve with a newer design double disc gate valve. Delete the associated leak-off valve and piping (excluding 1-SHV-71-14). Add a ¾" test line to bottom of new valve body for between-seat leak testing. Install new motor operator to meet EQ and GL 89-10 requirements, including T-drains and grease relief valve for gear case. Bypass the torque switch in the motor operator control circuit. Install test line with test and shutoff valves for 10CFR50 Appendix J testing. Applicable to (1-FCV-71-3, -6A, -6b, -7a, -7B, -8, -9, -17, -18, -25, -34, -37, -38, -39; 1-SHV-71-14 & 1-PCV-71-22). For check valves (1-CKV-71-597, -598, -599, & -600), install a 2-inch gate valve (1-SHV-71-520) in the RCIC turbine exhaust vacuum relief piping to facilitate Appendix J testing. Replace (1-CKV-71-520) with a new T-pattern globe lift check valve. Replace (1-FCV-71-40) with a new pneumatic testable check valve. Replace valve (1-FCV-71-59) and associated motor operator.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Reactor Core Isolation Cooling DCN 51220	Perform various electrical modifications to RCIC System valves (1-FCV-71-3, -8, -9, -10, -17, -18, -25, -34, -38, -39, & -59). Disconnect existing power and control wiring to the MOVs, remove or abandon cables/conduits and replace existing internal wiring with EQ wiring. Relocate power supplies. Remove local control switches. Remove power from valve (1-FCV-71-59) to maintain valve deenergized and open by opening associated 480V Reactor MOV Board 1A breaker. Replace limit switches for (1-FCV-71-10) for valve mid-position indication. Provide 250V dc power to new solenoid-operated RCIC steam line trap bypass valve (1-LCV-71-5); valve to fail closed on loss of power. Provide for automatic restart of RCIC System upon a reactor vessel low water level signal following a reactor vessel high water level trip per NUREG-0737. Remove the electronic overspeed trip function from the RCIC turbine per GE SIL No. 382. Replace existing GE relays (1-RLY-71-13A-K9 & -K42) with Agastat time delay relays and change setpoint of relay (1-RLY-71-13A-K42) in panel (1-25-31) from 30 seconds to 90 seconds to allow RCIC condensate pump to operate until low level is reached without activating annunciator (LA-71-29), RCIC GLAND SEAL VACUUM TANK LEVEL HIGH (XA-55-3B, Window 20). Replace and/or reroute electrical wiring/cables and replace components and instruments to meet EQ requirements, Appendix R breakage requirements, and to resolve electrical and instrument issues/concerns.	Y
Reactor Core Isolation Cooling DCN 51236	Equivalent instrument replacements: Replace existing (1-PDIS-71-1A & 1B) with (1-PDT-71-1A & 1B). Replace (1-PS-71-1A, 1B, 1C, & 1D) to meet EQ and Class 1E requirements. Replace (1-PS-71-21A) due to failed accuracy evaluation and obsolescence. Replace (1-FS-71-36) with (1-FIS-71-36). Replace RCIC Turbine Exhaust High Pressure switches (1-PS-71-13A & -13B). Replace flow solenoid valves (1-FSV-71-6A & -6B) due to obsolescence. Replace flow transmitters (1-FT-71-1A & -1B) due to obsolescence. Replace pressure transmitters (1-PT-71-4, -12, & -35) due to obsolescence. Replace pressure switches (1-PS-71-11A, -11B, -11C, & -11D) due to obsolescence. Replace temperature switches (1-TS-71-2A, -2B, -2C, -2D, -2E, -2F, -2G, -2H, -2J, -2K, -2L, -2M, -2N, -2P, -2R, & -2S) due to obsolescence. Refurbish instrument panels (1-25-7A & 1-25-58). Add new RCIC Turbine Control Panel (1-LPNL-925-672).	Y
Auxiliary Decay Heat Removal DCN 51197	Auxiliary Decay Heat Removal system was established in 1997 when Unit 1 was not operating. Provide auxiliary decay heat removal capability such that RHR system can be made available for maintenance soon after reactor shutdowns. Route new 12-inch and 14-inch piping and components to and from the fuel pool to provide decay heat removal.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
High Pressure Coolant Injection DCN 51083	Remove, abandon, reroute, replace various cables in the HPCI System to resolve Class 1E, Environmental Qualification (EQ), train separation, and breakage issues.	Y
High Pressure Coolant Injection DCN 51150	Replace solid wedge gate valve (1-FCV-73-2) with newer design double disc gate valve. Delete the associated leak-off valve and piping, as applicable. Add a ¾" test line to bottom of new valve body for between-seat leak testing. Install new motor operator to meet EQ and GL 89-10 requirements. Replace existing cable, conduit, and conduit supports for this new MOV and bypass the torque switch in the motor operator control circuit, as applicable. Upsize power cabling to new MOV operator due to larger motor, as applicable.	Y
High Pressure Coolant Injection DCN 51198	Replace motor actuator and spring pack for valves (1-FCV-73-36, & -40) and provide live-load packing and smart stem. Cut and cap stem leak-off lines, as applicable. Replace solid wedge gate valve (1-FCV-73-3) with newer design double disc gate valve. Delete the associated leak-off valve and piping, as applicable. Add a ¾" test line to bottom of new valve body for between-seat leak testing, as applicable. Install new motor operator to meet EQ and GL 89-10 requirements, including T-drains, as applicable. Replace motor actuator and spring pack for valve (1-FCV-73-18) and provide live-load packing and smart stem. Cut and cap stem leak-off lines, as applicable. This valve is changed from globe to a gate valve. Replace motor actuator and spring pack for valve (1-FCV-73-16) and provide live-load packing and smart stem. Cut and cap stem leak-off lines, as applicable. Opening time is increased from 20 seconds to 30 seconds. The new valve has body drain which is plugged. Replace existing EG-R hydraulic actuator (1-SM-73-190) for HPCI Turbine control valve (1-FCV-73-19) with a device qualified by GE. Replace HPCI booster pump suction relief valve (1-RFV-73-506) and lower set pressure from 150 psig to 55 psig per GE SIL No. 129. Replace previously removed HPCI pump test flow control valve 1-FCV-73-35 with a new valve and provide live-load packing and smart stem. Replace the motor operators and valve stem packing on valves (1-FCV-73-26, -34, & -44) and plug stem leak-off lines. Replace testable check valve and pneumatic operator on (1-FCV-73-45). Replace check valve (1-73-603) with a new 'T' pattern globe lift check valve. Add new 2-inch gate isolation valve downstream of check valve (1-73-24) and upstream of penetration X-222. Replace motor actuator and spring pack for valve (1-FCV-73-30) and provide live-load packing and smart stem. Cut and cap stem leak-off line. Add a 4-inch isolation gate valve (1-SHV-73-652) between (1-FCV-73-30) and the connection to the 18-inch RHR test line. Refurbish/ upgrade GE supplied HPCI turbine/pump skid to included impeller replacement and seismic qualifications.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
High Pressure Coolant Injection DCN 51221	Replace existing cables for new level switches (1-LS-73-56A, -56B, -57A, & -57B) (Ref. DCN 51237). Replace existing relay (23A-K17) with time delay relay (1-RLY-73-29-1) to retard the low suction pressure trip function of (1-PS-73-29-1) for 7 seconds. Replace HPCI booster pump suction pressure switch (1-PS-73-29-1) with a Class 1E, EQ device. Replace time delay relays (23A-K43 & -K51) for HPCI discharge pump and suppression chamber High Pressure, with (1-RLY-73-23AK43, & -51) in panel (1-9-39). Replace (LCV-73-5) HPCI condensate drain pot drain valve, with a manual valve. Replace various obsolete handswitches and temperature and level instruments, and upgrade wiring, splices, and connectors to Class 1E, EQ.	Y
High Pressure Coolant Injection DCN 51237	Equivalent instrument replacements: Replace existing (1-LS-73-56A, -56B, 57A, & -57B) Replace the following as a result of design/programs such as EQ & Class 1E requirements. Replace (1-LS-73-5). Replace (1-LS-73-8 with 1-LS-73-8A, & -8B) to allow separate alarm and control functions. Replace HPCI Steam Flow switches (1-PDIS-73-1A & -1B). Replace HPCI Steam Supply pressure switches (1-PS-73-1A, -1B, -1C, & -1D). Replace HPCI System minimum flow switch (1-FS-73-33) with a non-indicating switch and add indicator (1-FI-73-33B). Replace HPCI System flow transmitter (1-FT-73-33). Replace HPCI Turbine Exhaust disc ruptured pressure switches (1-PS-73-20A, -20B, -20C, & -20D). Replace HPCI Turbine Exhaust pressure switches (1-PS-73-22A, & -22B). Replace HPCI Booster Pump suction pressure switch (1-PS-73-29-1). Replace HPCI Turbine instruments (1-SE-73-51) turbine speed pick-up; and (1-TE-73-54B, -54H, & -54J), turbine bearing thermocouples. Replace Gland Seal Condensate Hotwell level switch high (1-LS-73-15A), and low (1-LS-73-15B). Replace HPCI Turbine Steam Line pressure transmitter (1-PT-73-4), Exhaust pressure transmitter (1-PT-73-21), Booster Pump suction pressure transmitter (1-PT-73-28), and Main Pump Discharge pressure transmitter (1-PT-73-31). Replace HPCI Steam Line Leakage temperature switches (1-TS-73-2A, B, C, D, E, F, G, H, J, K, L, M, N, P, R, & S). Refurbish instrument panels/racks (1-25-7B, -25-50, & -25-63).	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Residual Heat Removal DCN 51151	Refurbish valve (1-FCV-74-48) and install new motor operator. Replace existing cables and conduits with new cables. Replace and upgrade materials for the 20-inch suction line and (2) -24-inch shutdown cooling/RHR return lines from first weld inside the drywell to their respective connections to the Reactor Water Recirculation System loops A & B piping. Replace check valves (1-CKV-74-661 & -662) currently installed in vertical piping and unsuitable for this application. Replace large bore valves (1-FCV-74-54, -68, & 1-HCV-74-49, -55, -69). Install new 2-inch Decon connections on the 20-inch suction line and (2) -24-inch shutdown cooling/RHR return lines to allow for future cleaning/decon activities. Eliminate air-actuator and testable feature from check valves (1-FCV-74-54 & -68) and change unit identification numbers (UNIDs) from 'FCV' to 'CKV'. Remove associated solenoid valves, limit switches, cables, handswitches, and indicating lights. Delete piping, valves (1-FCV-74-78, -690, -691, -694, -695 & -697) and associated wiring from reactor vessel head (nozzle N6A) to the drywell penetration to eliminate the head spray function and support RVLIS modifications. Eliminate bonnet vents from valves (1-HCV-74-49, -55, &-69) and delete bonnet vent and body drain from (1-FCV-74-48).	Y
Residual Heat Removal DCN 51199	Replace pressure indicators (1-PI-74-117 & -133) on drain pump "A" suction and pressure indicators (1-PI-74-118 & -134) on drain pump "B" suction. Replace temperature elements (1-TE-74-81, & -82) and (1-TE-74-9, -21, -32, & -43) on the discharge and inlet of RHR heat exchangers. Modify instrument panels (25-2, -62, & -224A): Replace thermowells (1-TW-74-111, -112, -115, & -116). Cut and cap vent lines to valves (1-FCV-74-102, -103, -119, & -120). Install block valves, test connections, and vent lines to allow leak testing of the Core Spray isolation check valves. Replace obsolete system relief valves including (1-RFV-74-509A, -509C, -528A, -528B, -578C, -578D, -587A, -587B, -659, -677, -578A, -578B, -701, -709). Remove cross-tie flow control valve (1-FCV-74-46) actuator and gate valve. Install smart stems on the following GL 89-10 valves (1-FCV-74-7, -30, -47, -53, -57, -58, -59, -60, -61, -67, -71, -72, -73, -74, & -75). Install bypass around the RHR Pump Seal Injection Water Heat Exchangers "A" & "C" and shutoff valves between RHR pumps and the heat exchangers to allow servicing the heat exchangers without removing the associated RHR pump form service.	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Residual Heat Removal DCN 51222	Replace cables with EQ cables, replace internal wiring, replace EQ components, and reroute cables, as applicable, on the following: RHR Pump 1A suction valve(1-FCV_74-1) RHR Shutdown Cooling valve (1-FCV-74-2) RHR Pumps A&C Min Flow bypass valve (1-FCV-74-7) RHR Pump 1C suction valve (1-FCV-74-12) RHR Shutdown Cooling suction valve (1-FCV-74-13) RHR Shutdown Cooling suction isolation valve (1-FCV-74-48) RHR Outboard valve (1-FCV-74-52) RHR Inboard valve (1-FCV-74-53) RHR Pressure Suppression Chamber isolation valve (1-FCV-74-57) RHR Pressure Suppression Chamber spray valve (1-FCV-74-58) RHR Test valve (1-FCV-74-59) RHR Containment Spray valve (1-FCV-74-60) RHR Containment Spray valve (1-FCV-74-61) RHR System I flush valve (1-FCV-74-104) RHR System I testable check valve (1-FCV-74-54) RHR Pump 1C (1-PMP-74-16) (1-FCV-74-102); (1-FCV-74-1119); Panel (1-9-32) RHR Pump 1B suction valve(1-FCV_74-24) RHR Shutdown Cooling valve (1-FCV-74-25) RHR Pumps B&D Min Flow bypass valve (1-FCV-74-30) RHR Pump 1D suction valve (1-FCV-74-35) RHR Shutdown Cooling suction valve (1-FCV-74-36) RHR Discharge crosstie (1-FCV-74-46) RHR Shutdown Cooling suction isolation valve (1-FCV-74-47) RHR Outboard valve (1-FCV-74-66) RHR Inboard valve (1-FCV-74-67) RHR Pressure Suppression Chamber isolation valve (1-FCV-74-71) RHR Pressure Suppression Chamber spray valve (1-FCV-74-72) RHR Test valve (1-FCV-74-73) RHR Containment Spray valve (1-FCV-74-74) RHR Containment Spray valve (1-FCV-74-75) RHR System I flush valve (1-FCV-74-106) RHR System II testable check valve (1-FCV-74-68) RHR Pump 1B (1-PMP-74-28) & RHR Pump 1D (1-PMP-74-39) (1-FCV-74-103); (1-FCV-74-1120); Panel (1-9-33)	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Core Spray DCN 51152	Replace 10-inch and 12-inch Core Spray piping in Drywell from the RPV to containment penetrations X-16a & b. Remove 1-inch bonnet vent lines including (1-SHV-75-27 & -55) and (1-VTV-75-27 & -55) from (1-HCV-75-27 & -55). Plug or cap bonnet vents. Rename (1-HCV-75-27 & -55) to (1-SHV-75-27 & -55). Install improved valve packing and remove leak-off lines for (1-FCV-75-26, & -54). Install live-load packing and hardware for (1-FCV-75-27, & -55) and remove leak-off lines. Replace existing cables and associated conduits inside Drywell with new cables and route in new conduits between penetrations and end devices. Recertify valves (1-SHV-75-27, & -55) to design conditions of 1250 psig at 575 Deg F.	Y
Core Spray DCN 51200	Replace ECCS suction strainers to provide acceptable head loss under all plant design conditions. Replace relief valves (1-RFV-75-507A, -507B, -507C, -507D, -543A, -543B, & -583). Add block valves and test connections to provide for local leak rate testing of check valves (1-CKV-75-606, & -607). Replace check valves (1-CKV-75-606, -607, -609, & -610). Add block valve and test connection upstream of (1-FCV-75-57) to eliminate need for freeze-plugging of associated piping for maintenance. For (1-FCV-75-9, & -37), install new valve and EQ motor operator, including T-drains for the limit switch compartment and motor. New valve to be furnished with smart stem, upgraded gland packing and leak-off connection plugged. For (1-FCV-75-22, & -50) install new EQ motor operator, including T-drains for the limit switch compartment and motor and a new threaded stem nut. Upgrade gland packing and remove leak-off valve. For (1-FCV-75-25, & -53) install new EQ motor operator, including T-drains for the limit switch compartment and motor and a new threaded stem nut. Additionally, modify the valve by drilling a 0.25" hole in the high-pressure side disc face to eliminate pressure binding. Upgrade gland packing and remove leak-off valve. For (1-FCV-75-2, & -30) install new EQ motor operator, including T-drains for the limit switch compartment and motor and a new threaded stem nut. Upgrade gland packing and remove leak-off valve. For (1-FCV-75-11, & -39) install new EQ motor operator, including T-drains for the limit switch compartment and motor and a new threaded stem nut. Upgrade gland packing and remove leak-off valve. For (1-FCV-75-23, & -51) install new EQ motor operator, including T-drains for the limit switch compartment and motor and a new threaded stem nut. Upgrade gland packing and remove leak-off valve. Add sediment traps for PSC head tanks "keep fill" function. Remove Core Spray drain pumps.	Y
Core Spray DCN 51223	Provide new cables/conduit and abandon existing cables in place for SOVs/MOVs/controls and other Core Spray system components:(1-SHV-75-27, -55, 1-FCV-75-2, -9, -11, -22, -23, -25, -30, -37, -39, -50, -51, -53, 1-FSV-75-57 & -58).	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Core Spray DCN 51238	Replace pressure indicators (1-PI-75-4, -13, -32, & -41). Replace pressure switches (1-PS-75-7, -16, -24, -35, -44, & -52). Replace pressure transmitters (1-PT-75-20, & -48). Replace flow transmitters (1-FT-75-21 & -49). Replace flow switches (1-FS-75-21, & -49). Replace temperature transmitters (1-TTS-75-69A, & -69B) Refurbish panels (1-25-1, -57A, -60, & -256) Revise calculations and setpoints for EPU.	Y
Containment Inerting DCN 51169	Remove existing H2 & O2 elements, sample lines, cables, valves, and associated hangers from the drywell. Add (2) new lines for sampling both H2 & O2 with valves (1-SHV-76-74, & -84 and 1-TV-76-75, & -85) at penetrations X-27F & X-52D.	Y
Containment Inerting DCN 51201	Install shutoff valve (1-SHV-76-538) , check valves (1-CKV-76-551, & -552) and pipe branching off existing 1-inch Traversing Incore Probe (TIP) nitrogen supply line to Drywell Control Air to provide a diverse nitrogen source. Install new pressure regulator/indicator (1-PREG-76-50) on TIP nitrogen supply line to provide stable nitrogen supply to TIP purge system. Replace devices, components, and cables due to obsolescence and to meet Class 1E & EQ standards (1-FSV-76-17, -18, -19, -24, & -503); 1-ZS-76-17A, -17B, -18A, -18B, -19A, & -19B). Replace relief valves (1-RFV-76-543, & -656). Replace flow transmitter/totalizer (1-FT-76-25) and pressure transmitter (1-PT-76-14). Route/reroute associated electrical cables/conduit.	Y
Containment Inerting DCN 51369	Remove existing Drywell O2 and Torus sample lines and associated supports. Cap and spare associated penetrations. Replace existing valves (1-FSV-76-49, -50, -55, -56, -57, -58, -59, -60, -65, -66, -67, & -68). Replace existing H2/O2 Analyzers 1A & 1B with one new analyzer. Relocate PASS source connections for Torus and Drywell gas sample points. Install new valve (1-FSV-43-87) in the Division I Torus sample return line, to divert H2/O2 Analyzer discharge flow to PASS sample panel. Included with this new valve are limit switches to provide indication at Control Room Panel 1-9-54.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Radwaste DCN 51154	Remove valves (1-FCV-77-14A, & 14B; 1-DRV-77-666, & -667; 1-VTV-77-632) and associated cables/conduit. Replace and upsize Clean RadWaste (CRW) heat exchangers in drywell equipment drain sump and provide seismic supports. Replace check valves (1-CKV-77-600, -603, -625, & -628) with valves having a 1/16" diameter hole in the disc to prevent possible over-pressurization among Drywell Equipment Drain, floor drain sump pumps, and Primary Containment Isolation Valves (PCIVs). Replace drain sump bypass valves (1-77-602, -605, -627, & -630) and associated piping and shutoff valves (1-77-601, -604, -624, -629). Replace the following instruments: (1-LT-77-1A, -1B, -14A, -14B; 1-TE-77-14; 1-FS-77-51) and associated cables/conduit. With these changes, the temperature control signal is deleted and pumps will operate on level controls.	Y
Radwaste DCN 51202	Replace flow control valves (1-FCV-77-15A, -15B, -2A, & -2B) with air operated ball valves, solenoid controllers, limit switches, and switch mounting brackets. Replace the following small bore valves: (1-DRV-77-, 636, & -1355; 1-TV-77-619, -620, -643, & -644) including piping and fittings. Add relays in panel (1-9-4) and revise wiring such that flow totalizers for Drywell Equipment Drain sump pumps (1A & 1B) will only count when pumps are running. Replace flow transmitters (1-FT-77-6, & -16) and delete converters (1-FM-77-6, & -16). Replace the following instruments, associated cables/conduit: (1-FSV-77-2A, -2B, -3, -15A, & -15B); (1-ZS-77-2AA, -2AB, -2BA, -2BB, -15AA, -15AB, -15BA, & -15BB). Replace (1-FSV-77-17 & 1-TIS-77-17). Add lead shielding blankets to the 6-inch CRW unlimited access area drain header at Reactor building floor Elev. 565', Col. P/R-3, S/R-6, & S/R-2; and to the 4-inch drain header on Elev. 565', 593' & 621', Col S/R-2.	Y
Radwaste DCN 51597	Modify/upgrade RadWaste sump/pump controls to achieve the following: monitor and control sump level, replace elapsed time meters, replace alternating action relay logic, replace manual leakage detection methodology, detect level signal wiring problems, control sump pump operation per existing level setpoints, provide a manual mode of monitoring and controlling sump levels, transmit sump level information to plant computer, provide quantitative inleakage information, and provide future monitoring and control capabilities.	Y
Spent Fuel Pool Cooling and Cleanup DCN 51203	Replace the following (1-LS-78-1A, -1B, -1C, 1D, -1E, -1F, & -1G; 1-PS-78-9, & -14), including associated cables/conduits. Replace thermowells (1-TW-78-8, -13, & -18) and associated fittings. Cut and cap existing crosstie between (1-PIS-78-11 & -16) and rewire annunciator (1-XA-78-51) to differentiate when Pump 1A, or 1B, or both 1A & 1B are running. Remove power from valve (1-FCV-78-62) to preclude spurious opening.	Y

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Spent Fuel Pool Cooling and Cleanup DCN 62160	Replace flow switch (1-FS-78-51), and associated cables/conduit.	Y
Spent Fuel Pool Cooling and Cleanup DCN 63631	Install a 2-inch ball valve, a welded 2-inch nipple, a 2-inch threaded cap, and a 6-inch X 2-inch weldolet at various locations of Spent Fuel Pool Cooling piping (primarily at heat exchangers outlet to Radwaste) to facilitate hydrolazing and reduce dose rates.	Y
Fuel Handling and Storage DCN 51204	Add grating and handrails to improve safety on Refueling platform. Replace entire fuel handling control; system utilizing variable speed motor drivers, a programmable Logic Controller (PLC), a solid-state electronic load weighing system for main hoist, software defined boundary zone. protection, new position indication system, updated controllers, an operators cab mounted display, new main trolley motor, new main trolley and mono-rail hoist power tracks, new main hoist assembly, new fuel grapple, updated video equipment, upgraded air system (per GE SIL 272), and an isolation transformer	Y
Primary Containment Temperature Monitoring DCN 51148	Replace (32) thermocouples and relocate (1-TE-70-7, -8, & -9). Upgrade cables for replaced thermocouples to environmentally qualified cables.	Y
Primary Containment Temperature Monitoring DCN 51170	Remove/delete existing Humidity Sensors (1-ME-80-36A & -36B) and associated cables and conduits. These loops were originally intended to assist in determining drywell liquid leakage which is now monitored by drywell sump level/flow.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Primary Containment Temperature Monitoring DCN 51232	Remove/delete existing Humidity instruments (1-MIT-80-36A & -36B) and associated cables and conduits. Revise setpoint for (1-T-56-4, 2-T-56-4, & 3-T-56-4). Issue initial setpoint and scaling documents for temperature recorder loops (1-T-68-37; 1-T-56-2, -3, & -4) for Reactor Water Recirculation and Reactor Temperature Monitoring.	Y
Standby Diesel Generators DCN 51016	Complete the Unit 1 connections to the Unit 1/2 Diesel Generator Unit priority Re-Trip logic by wiring connections from the Unit 1 Re-Trip relay contacts in series with the Unit 2 Re-Trip relay contacts, Relays (10A-K132A, & B and 10A-K134A, & B). Complete the Unit 1 connections to the Unit 1/2 Diesel Generator for ECCS preferred pump logic.	Y
Containment Atmosphere Dilution DCN 51205	Replace the following valves: (1-FSV-84-8A, -8B, -8C, & -8D). Replace control and power cables associated with these valves, with EQ cables. New valves meet ASME Section III, Class 2, Seismic Category I, Class 1E, and 10CFR50.49 (EQ) requirements. Add test connections, block valves, and test valves to facilitate Appendix J leak testing. Provide a backup source of nitrogen from the Containment Atmosphere Dilution (CAD) System to Drywell Control Air system. Provide a backup source of nitrogen from CAD to the Suppression Chamber/Reactor Building Vacuum breaker valves (1-FCV-64-20, & -21). Provide a backup source of nitrogen from CAD to the Hardened Wetwell Vent PCIVs (1-FCV-64-221, & -222). Modify the CAD Vent Pipe Control loop that includes (1-FCCV-84-19), to add an expansion loop to reduce pipe stresses and pipe support loads. Replace various instruments, components, cables/conduit that are obsolete or to address EQ issues. Reconnect Trains A & B CAD nitrogen supply lines from their respective Nitrogen Storage Tank (A & B) to the U1 Drywell and Suppression Chamber. Replace Train A, CAD Vaporizer Power cable splice ($ES-153A).	Y
Control Rod Drive DCN 50985	Provide Control Rod Drive Housing (CRDH) lateral seismic restraints in lower pedestal cavity.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Control Rod Drive DCN 51078	Remove Rod Sequence Control System (RSCS). Remove components of instrument loops (1-P-85-61A, -61B, & -61C) from panels (1-25-110 & -111), and abandon or remove associated cables. Remove group notch logic module for the Rod Sequence Control logic from panel (1-9-28). Remove Logic Card and Aux. Buffer Boards for the Rod Sequence Control Logic and handswitch (1-HS-85-3A/S12) from panel (1-9-27). Replace existing Reactor Manual Control System (RMCS) Automatic Sequence Timer (1-TMR-85-3A/S4) with two Programmable Logic Controllers (PLCs) (1-PLC-85-3A/S4A, & -3A/S4B) with one PLC being an installed spare.	Y
Control Rod Drive DCN 51206	Replace obsolete CRD pump suction relief valve (1-RFV-85-505A). Replace valve (1-ISV-85-586) and relabel as (1-SHV-85-586). Replace packing for the following valves with packing to meet EPRI guidelines: (1-FCV-85-56; 0-SHV-85-500; 1-SHV-85-504A, -516A, -517, -552, -555, -556, -559, -561, -562, -563, -564, -565, -566, -568, -569, -572, -577; 1-BYV-85-519A, & -551; 1-THV-85-527). Replace seal injection flow control valves (1-FCV-85-54, & -55) based on GE recommendations. Replace CRD system flow control valves (1-FCV-85-11A, & -11B). Revise the N2 charging cart relief valves (1-RFV-85-604 & -609) setpoint from 1150 psig to 1200 psig. The system design temperature for a portion of the CRD hydraulics return to RWCU system is revised to 545° F. Install a second door to each Unit 1 Scram Discharge Instrument Volume (SDIV) cage. Modify SDIV level instrumentation to improve response time for inputs to the RPS scram logic by increasing diameter of piping, fittings, and valves for (1-LS-85-45C, -45D, -45E, & -45F) to 2-inches. Disable and abandon Unit 1 low scram pilot air header pressure switches and associated pressure indicators (1-PS-85-35A1, -35A2, -35B1, -35B2: 1-PI-85-35A, & -35B). Remove Scram Discharge Header ultrasonic level detectors (1-LE-85-85A, -85B, -85C, & -85D).	Y
Control Rod Drive DCN 51240	Replace obsolete pressure and level instrumentation of the Hydraulic Control Units with equivalent instrumentation. Replace scram pilot solenoid valves with qualified valves. Install a continuous backfill to the Reactor Vessel Level Instrumentation System reference legs. Install Alternate Rod Insertion system scram and vent valves to meet Anticipated Transient Without Scram (ATWS) requirements. Refurbish CRD local panels. Install a differential pressure indicator across the CRD Pump 1A strainer. Install a new permanent sample station to sample condensate flowing from the condensate storage tanks to the CRD drive water pumps.	Y
Radiation Monitoring DCN 50583	Replace obsolete flow (current) switches (1-FS-90-134B, & -134C) in panel (1-9-93)	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Radiation Monitoring DCN 51171	Remove existing Containment High Range Radiation Monitor (CHRRM) Detectors (1-RE-90-272C, & -273C) and associated cable and conduit from the drywell. Modify penetrations (X-46, & X-105A) by extending the penetrations 15-inches further into the drywell to house CHRRM detectors (1-RE-90-272A, & -273A).	Y
Radiation Monitoring DCN 51241	Replace Air Particulate Radiation monitors (1-RM-90-50, -55, -57, & -58). Replace Main Steam Line Radiation monitors (1-RM-90-136, -137, -138, & -139). Replace flow control valves with flow solenoid valves, rework sample lines, and add Appendix J test connections for:(1-FSV-90-254A, -254B, -255, -257A, & -257B). Replace Primary Coolant Leak Detection (PCLD) Continuous Air Monitor, (1-RM-90-256), replace heat tracing and controls: (1-TS-90-256, 1-RM-90-256, 1-RE-90-256-A, 1-RE-90-256-B, 1-FE-90-256, 1-HTR-90-256, 1-PMP-90-256, 1-PREG-90-256, 1-XI-90-256, 1-XX-90-256A, 1-XX-90-256B, 1-HS-90-256B, -256C, -256D, & -256E). Remove (1-RE-90-133, -133A, -134, -134A) and associated pre-amps, cabling and raceway. Rework sample lines for loops (1-R-90-133, -134, -131, & -132. Replace drywell Radiation Detectors (1-RE-90-272A, & -273A) and install new cables, as needed. Remove cables and raceways associated with (1-RE-90-272C, & -273C) in U1 Reactor Building.	Y
Neutron Monitoring DCN 51079	Replace existing Power Range Monitor electronics with new Nuclear Measurement Analysis and Control (NUMAC) digital Power Range Neutron Monitoring (PRNM) hardware to address GL 94-02. Install new Traversing Incore Probe (TIP) system devices (NUMACs) to replace existing Drive Control Channels A thru E. Install TIP isolation reset Hand Switch and a new relay for PCIS logic seal-in. Perform minor modifications to the Intermediate Range Monitors (IRMs) and Source Range Monitors (SRMs) chassis and SRM Test Switch.	Y
Neutron Monitoring DCN 51158	Replace Source Range Monitor (SRM), Intermediate Range Monitor (IRM), and Local Power Range Monitor (LPRM) cables, detectors, and associated equipment within the drywell and specific portions of the reactor building and reactor vessel.	Y
Neutron Monitoring DCN 61728	Replace existing obsolete Unit 1 Neutron Monitoring 24V dc battery chargers (4). The new chargers have current limit setting of 110%.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Traversing Incore Probe DCN 51172	Provide mounting, installation, and connection of Index Mechanisms (1-MCHR-94-101A thru -101E), to include replacement of Indexer incoming TIP tube from Penetration (1-MPEN-100-35A thru -35E) flange to indexer and Indexer outgoing TIP tubes from indexer to associated LPRM detector assembly connection. Replace blind flange on each indexer tubing penetration listed above and connect it to the Drywell TIP tube to each indexer. Rework N2 purge tubing at indexers and change connection from outboard to inboard side of each indexer.	Y
Traversing Incore Probe DCN 51242	Replace TIP Integrated Drive Mechanisms (1-MCHD-94-101A thru -101E) with upgraded units. Upgraded units to include: DC Drive Motor, allow use of existing field cables, allow use of Gamma TIP style detector, and externally mounted motor starter. Replace TIP Chamber Shields (1-SHDP-94-101A/A, -101B/B, -101C/C, -101D/D, & -101E/E). Replace Shear Valves (1-XCV-94-506, -507, -508, 509, & -510) due to age and valves can not be non-destructively tested. Perform cycle and leak tests on TIP Guide Tube ball isolation valves (1-FCV-94-501, -502, -503, -504, & -505).	Y
Reactor Water Recirculation Flow Control DCN 51219	Remove relays, indications, ammeters, resistors, fuses, instrument and power transformers, diodes, and handswitches from local control panels (1-LPNL-925-23, & -24). Install (3) Motor Management Relays (MMRs) per panel to provide Recirculation motor ground fault, overcurrent, phase reversal, and differential protective functions and trip the associated Variable Frequency Drive (VFD) and VFD feeder breakers. Install (3) Digital Frequency Relays (DFRs) per panel for redundant overfrequency protection. Replace Recirculation Pump Differential Pressure Transmitters (1-PDT-68-65, & -82) with transmitters that have a 4-20 mA output signal for compatibility with control system software.	Y
Reactor Protection DCN 51080	Remove condenser low vacuum trip logic. This was an anticipatory trip and no FSAR transient and accident analysis credit was taken for this feature. Delete CRD air header low pressure trip function. Replace obsolete time delay relays (1-RLY-99-1AK4, & -1AK4B in RPS MG Set Control Panels. Install test switches (1-HS-85-37AA & -37BA) for testing the Scram Discharge Volume Vent and Drain Pilot Valves (1-FSV-85-37A, & -37B).	Y
Penetrations DCN 51159	Replace primary containment electrical penetration assemblies (EPAs) (1-EPEN-100-110A, 100A, & -104F) with environmentally qualified EPAs.	Y
Penetrations DCN 51208	Inspect, document, and install as necessary, fire barrier seals for penetrations between fire zones (1-1, 1-2, 1-3, 1-4, 1-5, & 1-6) in Unit 1 Reactor Building. Replace Doors (490, 635, & 670), including frames and hardware, in Unit 1 Reactor Building, with fire rated doors and designations.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Cranes and Hoists DCN 51740	Install a jib crane above each of three (3) sets of Combined Intercept Valves (CIVs) and relief valves (1-FCV-1-96 & 1-1-553; 1-FCV-1-99 & 1-1-561; & 1-FCV-1-102 & 1-1-567).	Y
Main Generator DCN 51133	Provide back-up power source to the Main Generator Breaker Air Compressor System (MGBACS) to provide redundant capability for operation of the Replenishing Valve Control circuits. Add parallel diodes across Diodes R7D & R8D for Main Generator Exciter Firing Control Circuit to eliminate a potential single point of failure. Add a resistor onto the Maximum Excitation Limit Panel Component board and add a resistor onto the Transfer Panel Component board (43A & J2KX relays). The additional resistors increase the conditioning effect for the boards and eliminate noise in the ground circuit. Remove existing field isolators and install a programmable Field Temperature Module (1-TM-242-45) in generator exciter cabinet to recorder (1-TR-242-59).	Y
Process Computer DCN 51082	Provide for the installation of a new Unit 1 Integrated Computer System (ICS). This modification adds a new redundant process computer, operator work stations, printers, I/O cabinets, I/O wiring, and interface to package systems via data-link. Package systems include Foxboro IA System (includes Reactor Water Recirculation, Reactor Feedwater, Feedwater Heater Drains, Moisture Separator, and Generator Temperature Monitoring) Reactor Recirculation Pump VFDs, Condensate Demineralizers, Containment Isolation System, Neutron Monitoring, Generator Hydrogen, Radwaste Sump Level Control, Turbine EHC, MCR Annunciators, And MCR Recorders.	Y
Civil Structures DCN 51019	Provide modifications to the Drywell Platform structural steel at Elev. 584'. The modifications include horizontal rigidity bracing for the platform due to revised seismic analysis, revised piping loads, NRC IE Bulletin 79-14, added cable trays and conduit.	Y
Civil Structures DCN 51020	Provide modifications to the Drywell Platform structural steel at Elev. 563'. The modifications include horizontal rigidity bracing for the platform due to revised seismic analysis, revised piping loads, NRC IE Bulletin 79-14, added cable trays and conduit.	Y
Civil Structures DCN 51088	Provide for the installation of new cable trays and raceway components in the Cable Spreading Room, Auxiliary Instrument Room, and Control Room in Unit 1. Also, provide transition raceway components to interface with Reactor Building and Turbine Building cable trays.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Civil Structures DCN 51160	Provide design details for cables requiring coating or beta shielding, for junction boxes and terminal boxes requiring sealing against moisture, for junction boxes and terminal boxes requiring ventilation and drainage, and for sealing of conduits terminating at cable trays, all within the Unit 1 Drywell. Additionally, provide details for replacing various Drywell junction boxes with boxes made of stainless steel.	Y
Civil Structures DCN 51286	Provide modifications to the Drywell Platforms structural steel at Elev. 604', 616', & 628'. The modifications are due to revised seismic analysis, revised piping loads, NRC IE Bulletin 79-14, added cable trays and conduit.	Y
Civil Structures DCN 51374	Modify the Unit 1 Reactor Building Elev. 551' Torus Access Platform structural members and associated connections. Modifications are to resolve identified platform deficient items such as insufficient welds, structural members, and anchorage. Structural components are added, modified, or replaced and field cut-outs and unaccounted attachments are evaluated and resolved.	Y
Civil Structures DCN 51375	Provide modifications to various structural steel platforms within the Unit 1 Reactor Building based on evaluation of the steel members, connections, surface mounted baseplates, anchorages, and/or evaluation of embedded plates.	Y
Civil Structures DCN 51377	Provide modifications to the piping penetration anchor frames in the Reactor Building.	Y
Civil Structures DCN 51519	Implement structural modifications necessary to qualify Miscellaneous Steel Support Frames (MSSFs) in the Unit 1 Reactor Building zone, outside of the Drywell, to the requirements of GDC 50-C-7100 and Seismic Design 50-C-7102. The MSSFs serve as structural attachment points for pipe supports and for secondary loads such as cable tray supports and HVAC duct supports. No new frames are added.	Y
Civil Structures DCN 51520	Provide for the modification of various steel platforms for the Core Spray Valve Access platform and Control Rod Drive Relief Valve Access platform, and addition/modification of HVAC duct supports in the Core Spray and RHR pump rooms.	Y
Civil Structures DCN 51521	Provide for modifications to the Unit 1 Reactor Building structural components required for A-46 qualification of cable tray and conduit supports.	Y
Civil Structures DCN 51560	Provide modifications to the Reactor Pressure Vessel (RPV) insulation support frame (base ring supported at Elev. 640') to ensure that frame displacements are within acceptable limits for support of Seismic Class I piping.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Civil Structures DCN 51669	Modify Seismic Class II items located in the Reactor Building, outside the drywell which, if not modified, would degrade the integrity of Class I items as identified by Seismic II/I Spray Evaluation Program. A total of eighteen outliers will require modification. One outlier identified by MSIV Seismic Ruggedness Verification Program, and located in the Reactor Building, is added to the scope of this modification.	Y
Civil Structures DCN 60268	Provide steel frames for permanent shielding at CRD suction/discharge lines, strainers/filters on Elev. 565' & 541' in NE quadrant of Unit 1 Reactor Building to reduce dose rates.	Y
120/208 VAC Electrical Distribution DCN 51085	Replace the existing 1KVA ECCS Analog Trip Unit (ATU) Inverters with 5KVA inverters. Replace the Unit Preferred Motor-Motor-Generator (MMG) Sets with an rectifier/inverter Uninterruptible Power Supply (UPS). Replace the Unit Preferred Transfomer with a regulating type transfomer. Install/Replace various 120V Distribution system fuses and breakers for proper coordination, protection and/or support of downstream load changes. Modify breaker settings for proper coordination and protection. Structural support modifications are made associated with USI-A46 and Seismic IPEEE Programs for the Control Building.	Y
120/208 VAC Electrical Distribution DCN 51214	Various cables in the 120V Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, App R, voltage drop/ampacity/short circuit, Design Criteria Requirements and cable separations analysis.	Y
250 VDC Electrical Distribution DCN 51110	Various cables in the 250V Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, App R, voltage drop/ampacity/short circuit, Design Criteria Requirements and cable separations analysis. Modify the internal components in the 250V Motor Control Center (MCC) cubicles to support changes to the loads and cables. Modify breaker settings for proper coordination and protection.	Y
250 VDC Electrical Distribution DCN 51215	Various cables in the 250V Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, App R, voltage drop/ampacity/short circuit, Design Criteria Requirements and cable separations analysis. Modify the internal components in the 250V MCC cubicles to support changes to the loads and cables. Modify breaker settings for proper coordination and protection.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
480 VAC Electrical Distribution DCN 51131	Various cables in the 480V Distribution System are replaced as required to support voltage drop/ampacity/short circuit and Design Criteria Requirements. Modify breaker settings for proper coordination and protection. Modify the internal components in the 480V MCC cubicles to support changes to the loads and cables.	Y
480 VAC Electrical Distribution DCN 51090	Various cables in the 480V Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, Appendix R, voltage drop/ampacity/short circuit, Design Criteria Requirements and cable separations analysis. A new isolation switch is installed for the Electric Board Room Air Handling Units 1A and 1B to satisfy Appendix R requirements. Modify the internal components in the 480V MCC cubicles to support changes to the loads and cables. Modify breaker settings for proper coordination and protection. Modify the 480V Load Shed Logic for the Drywell Blowers for both Units 1 and 2 and the Control Bay Chilled Water Pumps A and B to satisfy Diesel Generator Loading requirements.	Y
480 VAC Electrical Distribution DCN 51216	Various cables in the 480V Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, App R, voltage drop/ampacity/short circuit, Design Criteria Requirements and cable separations analysis. Modify the internal components in the 480V MCC cubicles to support changes to the loads and cables. The 480V Shutdown Boards 1A and 1B oil filled 750KVA transformers are replaced with dry type 1000KVA transformers to meet system load requirements. Isolation fuses are installed in 4160V Shutdown Board BD power feed to 480V Shutdown Boards 1E transformer to eliminate an associated circuit concern for Appendix R requirements. Remove LPCI Motor-Generator Sets and abandon in place the Reactor MOV Boards 1D & 1E.	Y[1]
4kV AC Electrical Distribution DCN 51087	Unit 1 4KV breakers are replaced with new vacuum style breakers. Fuses are installed in 4KV Shutdown Boards to provide isolation of control circuit cables to satisfy Appendix R requirements.	Y

1 The removal of the LPCI M-G sets is unique to Unit 1.

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
4kV AC Electrical Distribution DCN 51217	Various cables in the 4KV Distribution System are added, replaced, rerouted, retagged or abandoned as required to support 10CFR50.49, Appendix R Ampacity/Voltage Drop and Cable Separations analyses. Replace the Terminal Blocks for the U1 Shutdown Board Cooling Units to complete documentation for the requirements of 10CFR50.49	Y
500/161kV Off Site Power DCN 51084	Add a provision to trip the Generator exciter field breaker when the turbine is tripped to prevent reverse power relay operation. Add a redundant Generator Backup Relay for tripping of the Generator to eliminate a single point failure of the Generator. Remove the Unit 1 Main Generator and Turbine trip initiations which are generated by the operation of the 64GF Generator Field Ground relay and add an additional alarm in the control room for operator action upon actuation of the relay to prevent unnecessary Generator trips. Install a blocking contact from Loss of Potential (Voltage Balance) Relay 160 into the Generator overcurrent trip circuit to prevent false tripping.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Miscellaneous DCN 50995 DCN 51012 DCN 51065 DCN 51066 DCN 51067 DCN 51068 DCN 51069 DCN 51254 DCN 51261 DCN 51263 DCN 51335 DCN 51336 DCN 51338 DCN 51339 DCN 51340 DCN 51341 DCN 51342 DCN 51343 DCN 51344 DCN 51345 DCN 51346 DCN 51347 DCN 51349 DCN 51351 DCN 51352 DCN 51353 DCN 51419 DCN 51420 DCN 51441	Evaluate piping supports and their configurations against applicable requirements from General Design Criteria, UFSAR Seismic Class I requirements, existing calculations, walkdown data, and NRC Bulletins IE 79-02 and 79-14. Perform piping support modifications as necessary to ensure piping and branch connections are qualified for deadweight, seismic, and thermal loads.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Miscellaneous DCN 51255 DCN 51256 DCN 51257 DCN 51258 DCN 51260 DCN 51262 DCN 51264 DCN 51334 DCN 51348 DCN 51408 DCN 51409 DCN 51410 DCN 51411 DCN 51412 DCN 51413 DCN 51414 DCN 51415 DCN 51416 DCN 51417 DCN 51418 DCN 51448 DCN 51449 DCN 51450 DCN 51452 DCN 51453	Evaluate piping, piping supports and their configurations against applicable requirements from General Design Criteria, UFSAR Seismic Class I requirements, existing calculations, and walkdown data, for all Seismic Class I piping/tubing less than 2.5-inch diameter. Perform piping and support modifications (including addition and deletion) as necessary to ensure piping and branch connections are qualified for deadweight, seismic, and thermal loads at EPU conditions.	Y

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Miscellaneous DCN 51091 DCN 51642 DCN 60073 DCN 60074	Replace safety related, quality related, and non-safety related fuses in the Unit 1 Control Bay, Reactor Building, and Turbine Building with like-for-like equivalent fuses. There are no changes to circuitry, no addition or deletion of any fuses, and no fuse-holder replacement, within the scope of this DCN. Unit 1 fuses, which are within the Operating Boundary of Units 2 or 3, are excluded from the scope of these DCNs. Fuses with common, Unit 2, or Unit 3 UNIDs, are excluded from the scope of these DCNs.	Y
Generator Cooling DCN 51140 (EPU)	Addition of flow and temperature switches (1-FS-35-65A, -B, -C and 1-TS/TW-35-71A, -B, & -C) to provide two out of three logic based turbine trip instrumentation. The new flow switches provide for a turbine trip on loss of cooling water flow to the generator. Provide for an increase in generator hydrogen pressure from 65 to 75 psig to support EPU conditions. Replace pressure switches (1-PS-35-18A, 18B, and -19) and revise setpoint (EPU). Recalibrate (1-PCV-35-5A, -5B, and -9) in support of EPU conditions. Eliminate Flow Integrator (1-FQ-35-8) to preclude potential hydrogen leakage. Add an excess flow check valve at the location where (1-FQ-35-8) was removed, to comply with fire protection code requirements. Replace obsolete Generator Seal Oil Vacuum Pump motor and gear box. Replace under-sized Generator Emergency Seal Oil Pump motor power cable to ensure minimum acceptable voltage. Replace Generator Exciter Flexible coupling per GE recommendation. Install Litten Veam Connectors/penetrations and Generator flux probe on generator housing. Add Foxboro I/A monitoring capability for generator stator and other related thermocouples.	N (EPU)
Condensate DCN 51401 (EPU)	Replace Condensate pump motors and impellers to accommodate increased flows required for EPU. Add an orifice plate downstream of FCV-2-29A to minimize pressure drop through the valve. Upsize associated motor power feed cables, replace switchgear ammeters with appropriately sized meters, and revise protective relay settings.	N (EPU)
Condensate DCN 51402 (EPU)	Replace Condensate Booster pumps and motors to accommodate increased flows required for EPU. New pump motors are water to air cooled and Raw Cooling Water heat exchangers are added. Upsized current transformers and power feed cables for the associated pump motors are provided. HVAC air flows are increased to the Condensate pumps/motors as due to the increased heat loads of larger motors being installed. HVAC air flows are reduced to the Condensate Booster pumps/motors due to the reduced heat load from the new water-cooled motors.	N (EPU)
Feedwater DCN 51403 (EPU)	Replace Unit 1 Reactor Feedwater (FW) Pumps (3), the FW pump/turbine couplings, and associated bearing temperature and vibration monitoring instrumentation to accommodate increased design flows required for EPU.	N (EPU)

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Main Steam DCN 51456 (EPU)	Retrofit the high pressure turbine with Advanced Design Steam Path (ADSP) to include a new rotor with new custom-designed diaphragms and buckets for EPU. Modify the size of the steam seal unloader valves and associated piping to accommodate the larger steam flow requirements.	N (EPU)
Main Steam DCN 51481 (EPU)	Provide GE designed and supplied turbine replacement components, including monoblock rotors and diaphragms for 3 LP turbines, in support of EPU.	N (EPU)
Condensate and Demineralized Water DCN 51457 (EPU)	Install a tenth Condensate Filter-Demineralizer and associated components such as, resin filter, holding pump, instrument panel/instruments, access platform, and demineralizer vessel shielding. Replace nine existing holding pumps with new, lower rpm pumps. These changes will maintain condensate flow below the 4000 gpm max flow rate for each Filter-Demin vessel at EPU conditions with one vessel out of service.	N (EPU)
Condensate and Demineralized Water DCN 51459 (EPU)	Replace the existing 16" line and 16" air-operated butterfly valve that provide for condensate to bypass the steam packing exhauster (SPE), with a 24" line and a 20" motor-operated butterfly valve. Permanently block the orifice contained within the SPE in the partition plate that separates the inlet and outlet of the waterbox.	N (EPU)
Condensate and Demineralized Water DCN 51462 (EPU)	Replace 71 Condensate demineralizer System valves and their associated pneumatic actuators with upgraded valve/actuator assemblies. Requires minor piping modifications to adjust face to face distances between flanges to accommodate the new valve bodies. Install new tube rack supports.	N (EPU)

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Heater Drains and Vents DCN 51464 (EPU)	Modify the shells, nozzles, and relief valves for Feedwater Heaters 1, 2, and 3 to be ASME Code compliant under EPU conditions. Provide the Feedwater Heaters 1, 2, 3, 4, and 5 pass partition plate modifications and manway stiffeners required for higher EPU pressures. Relocate the Extraction Steam nozzles on #3 Feedwater Heater and add a steam duct/impingement plate internal to the heater to protect the shell and to provide improved steam distribution within the heater. Modify the Extraction Steam piping to match the new nozzle locations.	N (EPU)
Main Steam DCN 51466 (EPU)	Make changes to the instruments identified in the BOP Instrument Study in support of EPU. Replace various local pressure gauges with new gauges and pulsation dampening snubbers. Re-calibrate various flow and pressure transmitters such that their ranges encompass new EPU operating conditions. Re-calibrate various pressure switches with new setpoints to account for new EPU operating conditions. Revise setpoint for pressure switches monitoring steam supply to Steam Jet Air Ejectors (SJAEs) from 180 to 187 psig.	N (EPU)
Main Generator DCN 51470 (EPU)	Upgrade Main Transformer system for plant operation at EPU conditions. The rating for each Main Transformer is increased from 400 to 500 MVA. Revise circuit for actuation of Lock-Out Relays (LORs) 186 & 186C to actuate on a signal from Qualitrol Multi Function Pressure Monitor (2 out of 3 logic) instead of from the sudden pressure relays. Add an interlock in the transformers cooling control circuit from LOR 186 & 186C. Delete interlocks from undervoltage relay 127T, to meet single failure criteria for loss of Relay 127T. Replace fire protection ring header for Unit 1 Main Transformer due to new transformers configuration and to comply with present code requirements. Relocation of existing heat detectors and addition of (3) detectors.	N[(2)] (EPU)
Condensate and Demineralized Water DCN 51477 (EPU)	Modify the Unit 1 condenser instrumentation to provide for improved performance monitoring under EPU conditions. Improve the accuracy of condenser pressure inputs to the Integrated Computer System (ICS). Provide additional Condenser Cooling Water (CCW) supply and return temperature data to the ICS and provide CCW flow input to ICS.	N (EPU)

2 Already installed on Unit 2.

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Feedwater DCN 51482 (EPU)	Replace rotors for each Unit 1 Feedwater Pump Turbine (FWPT) to include new stages 1 & 2 buckets per current design and newly designed stages 3-6 buckets to support EPU conditions. Included will be newly designed stage 6 diaphragms and (3) new mechanical overspeed trip governors, all furnished by GE.	N (EPU)
Feedwater DCN 62024	Revise thermal ratings of the Feedwater System for EPU.	N (EPU)
Feedwater PIC 63881 (EPU)	Upgrade seal injection for new Feedwater pumps.	N (EPU)
Gen Bus Duct Cooling DCN 60598 (EPU)	Replace Isolated Phase Bus (IPB) duct cooling coil (1-CLR-262-1) with the new coil sized for 200 gpm flow and 2.5 million BTU/hr cooling to support EPU. Replace existing IPB duct cooling air supply fan (1-FAN-262-1) and motor (1-MTR-262-1) with two new fan/motor assemblies (1-FAN-262-1A, & -1B; 1-MTR-262-1A, & -1B). Delete existing wiring, cables, and control switches and replace with new wiring, cables, and control switches to power the new fans/motors. Raw Cooling Water piping is modified to make the existing dual inlet and outlet piping to cooling coil, a single inlet and outlet configuration. Add Raw Cooling Water hydraulic calculations.	N (EPU)
Sampling and Water Quality DCN 51185	Install a scaled-down Post Accident Sampling System for Unit 1. See Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler TSTF-413. The modified system provides a means to sample reactor coolant, suppression pool, and containment atmosphere at a sample station (1-LPNL-925-365). Included are additions of RHR liquid sample line and H2/O2 monitoring gas sample line for the Post Accident Sampling System (PASS). Replace existing solenoid valve (1-FSV-43-14) with a Class 1E and EQ solenoid valve. New valve to be supplied with stem seal packing which meets EPRI guidelines.	N
Sampling and Water Quality DCN 51235	Replace selected RWCU related instruments as a result of design/programs, age, degradation, & obsolescence. Replace RWCU Sample panel & provide sampling capability from Drywell sump pumps discharge to aid in monitoring identified & unidentified leakage & investigations. Install qualified leak detectors for RWCU & related pipe rupture.	N

Description of Modifications Planned for BFN Unit 1 Restart

System and Design Change	Description of Change	U2/U3 Related DCN(Y/N)
Annunciators DCN 51107	Replace Unit 1 Annunciation System. New system to fit into existing panel spaces and has added capability to provide alarm status and sequences from Integrated Computer System (ICS) displays using Programmable Logic Controllers (PLCs). Remove existing annunciator hardware, circuit cards, lamp holders, and wiring, inside and outside the annunciator window boxes. Install a mounting plate with two PLCs, ladder logic programmed Input/Output (I/O) cards, relay cards, fuses, and terminal blocks with multi pin connectors mounted inside each original Annunciator Window Box facing the rear of each Main Control Room (MCR) panel. Existing field wiring will land on new terminal blocks and be jumpered to allow both PLCs to have identical auctioneered inputs. Modify MCR front panels, above each Annunciator Window box, to accommodate four Light Emitting Diode (LEDs), long-life bulbs. Existing 48V dc to 120V ac inverters are removed and replaced with two 48V dc to 24V dc power supplies per MCR panel. Replace the current annunciator power supply 48V dc distribution system and Automatic Bus Transfer (ABT) switch in Panel (1-9-9, CAB 1) with two fused distribution panels. Replacement of the Operations Recorder equipment will occur at one time using PLC based equipment Real Time Products (RTP) system and this installation will affect all 3 units. This system consists of two high density I/O racks and processors located in Bay 94 in the Communications Room. Existing light bulbs in the window box on panel (9-8) will be replaced with 24V LED bulbs on all three units. The 120V ac RTP will be powered from Unit 3 ICS distribution panel (25-525).	N
Temperature Monitoring DCN 51165	Provide for equivalent replacement of system 003, (Reactor Feedwater), system 056, (Temperature Monitoring), and system 068 (Reactor Water Recirculation) thermocouples, mounting hardware, and associated cables/conduits to satisfy component reliability due to age, time in harsh environment, and degradation.	N
Temperature Monitoring DCN 51232	Replace obsolete Control Room temperature recorders (1-TR-56-2, -3, -4, and -37) with digital paperless recorders.	N
Radiation Monitoring DCN 61999	Delete Off Gas monitor (1-RM-90-160) and both Torus Area Monitors (1-RM-90-272B, & -273B). Replace Off Gas monitor (1-RM-90-157) with a suitable drawer detector to detect early onset of fuel failure.	N
Radiation Monitoring DCN 62861	Turbine Building Radcon Continuous Air Monitors (CAMs) (1-RM-90-51, -53, -54, -56, & -59) will not communicate with the upgraded Control Room module.	N

UNIT 1 PROJECT SCOPE

COMMODITY	APPROXIMATE PROJECT TOTAL
Piping - Large Bore	16,366 feet
Hangers - Large Bore	1,745
Piping - Small Bore	27,630 feet
Hangers - Small Bore	6,132
Conduit	162,159 feet (31 miles)
Conduit Supports	19,299
Cable Terminations	102,788
Cable	844,319 feet (160 miles)
Large Pumps	21
Large Motors	19
Large Valves	1,066
Small Valves	~8,000

NDE EXAMINATIONS PERFORMED FOR ORIGINAL, NON-REPLACED PIPING (sheet 1 of 3)

SYSTEM	LR DRAWING	LOCATIONS	TYPE EXAM	COMMENTS
RHRSW (A&C loops in tunnels)	1-47E858-1-LR	8 piping areas	UT thickness	Scanned grid blocks at susceptible areas [1]
Drywell Liner		4 areas	UT thickness	Maintenance activity scheduled every 3 years during lay-up period
Fire Protection	1-47E850-5-LR	41 piping areas (~200 feet of pipe)	UT thickness	Scanned circumference of pipe at susceptible areas [2]
EECW[3]	1-47E859-1-LR	3 piping areas	UT thickness	Scanned grid blocks at susceptible areas [1]
		~30 feet of dead leg pipe	UT thickness	Scanned grid blocks at approximate 1 foot intervals [2]
RCW[3]	1-47E844-2 LR	~60 feet of dead leg pipe	UT thickness	Scanned grid blocks at approximate 1 foot intervals [2]
CRD	1-47E820-2-LR	6 welds	UT shear wave and surface exam	
	1-47E820-6-LR	6 welds	UT shear wave and surface exam	
CORE SPRAY	1-47E814-1-LR	14 welds	UT shear wave and surface exam	

NDE EXAMINATIONS PERFORMED FOR ORIGINAL, NON-REPLACED PIPING (sheet 2 of 3)

SYSTEM	LR DRAWING	LOCATIONS	TYPE EXAM	COMMENTS
FEEDWATER	1-47E803-1-LR	27 welds	UT shear wave and surface exam	
		17 piping areas	UT thickness	Scanned grid blocks at susceptible areas [1]
HPCI	1-47E812-1-LR	20 welds	UT shear wave and surface exam	
	1-47E813-1-LR	4 piping areas	UT thickness	Scanned grid blocks at susceptible areas[1]
MAIN STEAM	1-47E801-1-LR	58 welds	UT shear wave and surface exam	
		34 piping areas	UT thickness	Scanned grid blocks at susceptible areas[1]
RCIC	1-47E813-1-LR	8 welds	UT shear wave and surface exam	
		6 piping areas	UT thickness	Scanned grid blocks at susceptible areas[1]
RHR	1-47E811-1-LR	35 welds	UT shear wave and surface exam	
RBCCW[3]	1-47E822-1-LR	1 Weld	UT shear wave and surface exam	

NDE EXAMINATIONS PERFORMED FOR ORIGINAL, NON-REPLACED PIPING (sheet 3 of 3)

Notes:

1. The piping was laid out with 4" x 4" grid blocks around the circumference of the pipe. Thickness readings correspond to the lowest reading taken in each grid block.
2. The piping was scanned around the entire circumference. Thickness readings correspond to the lowest reading taken around the circumference. Readings taken at approximate 1 foot intervals.
3. The majority of this system was in service with water flow in the system during the layup period.

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Main Steam 001	Drywell	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Refurbishment of Containment Isolation valves • Replace drain line isolation valve
Main Steam 001	Reactor Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Refurbishment of Containment Isolation valves • Replace drain line isolation valve
Main Steam 001	Turbine Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged except for the cross-under/cross-over piping described below • Refurbishment of turbine control and stop valves
Main Steam Cross-Under / Cross-Over 001	Turbine Building	Maintenance Work Order	• Unit 1 operational history • Cleanliness Verification	• All of the Cross-Under piping (HP Turbine to Moisture Separators) replaced due to improper material in initial piping • Selected portions of the Cross-Over Piping (Moisture Separators to Combined Intermediate Valve) replaced • Replacement piping was 2-1/4% Cr. material
Condensate 002	Turbine Building	DCN 51401 & DCN 51402	• System component integrity wall thickness measurements • EPU impact on equipment requirements	• Piping system remains unchanged • Condensate pump impellers and motors replaced for extended power uprate operation • Condensate Booster pumps replaced for extended power uprate operation
Reactor Feedwater 003	Drywell	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Feedwater check valves replaced for Stellite reduction
Reactor Feedwater 003	Reactor Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Feedwater check valves replaced for Stellite reduction

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Reactor Feedwater 003	Turbine Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Minimum flow valves replaced due to wear experience on Units 2 and 3 • Minimum flow piping to condenser replaced with stainless steel to prevent FAC • Remaining piping inspected satisfactorily and remains unchanged
Extraction Steam 005	Turbine Building	DCN 51116 & Maintenance Work Order	• Units 2&3 Restart Lessons Learned • Units 2&3 FAC program results • System component integrity wall thickness measurements • Cleanliness Verification	• Heater's 2, 3, 4 & 5 piping inside and outside of the condenser replaced with 2-1/4% Cr. material to prevent FAC • Heater 1 piping remains unchanged
Heaters Drains & Vents 006	Turbine Building	DCN 51116 & Maintenance Work Order	• Units 2&3 Restart Lessons Learned • Units 2&3 FAC program results • System component integrity wall thickness measurements • Cleanliness Verification	• Pipe sizes typically 2" and smaller replaced with 2-1/4% Cr. material to prevent FAC • Selected sections for inspections/replacements based on FAC experience from Units 2 and 3 • • Replaced Heater Drain and Moisture Separator Level Control valves for improved flow control and reliability
Residual Heat Removal Service Water 023	Reactor Building	DCN 51177	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements on Loops "A" & "C" • Loop "B" & "D" in operation supporting Units 2 & 3	• Complete like-for-like replacement of Loop I carbon steel piping • LoopII inspected with no replacement required (continuously operated in support of Unit 2/3 operation • Replacement of all four discharge flow control valves for improved flow control

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Raw Cooling Water 024	All Buildings	Maintenance Work Order	• Portions of system remained in operation to support operation of Units 2 and 3	• Satisfactory inspection of large bore piping. Large bore piping remains unchanged. • Approximately 3000 feet of small bore piping replaced like-for-like due to corrosion caused by improper layup • Selected dead legs removed from the plant due to piping no longer required due to equipment changes. • Other dead legs remain in place to support intermittent operations.
Fire Protection 026	Reactor Building	DCN 51180 & Maintenance Work Order	• System component integrity wall thickness measurements at selected locations of vertical main risers which were not replaced	• Replacement of the header and branch piping in reactor building with galvanized carbon steel to bring system into conformance with NFPA code
Condenser 027	Turbine Building	DCN 51113	• Replacement of tubes containing Copper • Cleanliness Verification	• Satisfactory inspection. Piping system and condenser structure remain unchanged • Replaced and upgraded condenser tube material to Sea Cure stainless steel to remove copper from the system.
Emergency Equipment Cooling Water 067	Reactor Building	DCN 51192	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Replacement of 4" & smaller piping with material changed from carbon steel to stainless steel (316/316L)
Reactor Water Recirculation 068	Drywell	DCN 51045	• IGSCC Issues	• Complete large bore replacement with IGSCC resistant 316NG materials • 2" and smaller piping replaced with stainless steel (316/316L) • Pumps and large bore valves refurbished

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Reactor Water Cleanup 069	Drywell	DCN 51046	• IGSCC Issues	• Complete replacement of piping with IGSCC resistant 316NG materials • Complete replacement of valves with 316L material
Reactor Water Cleanup 069	Reactor Building	DCN 51194	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Complete replacement of hot piping (316NG) and regenerative heat exchangers (316L) (3 heat exchangers) • Piping rerouted to cool water before water enters pumps to increase pump seal life • Complete replacement of valves with 316L material in hot segments of piping
Reactor Building Closed Cooling Water 070	Drywell	DCN 51148	• Units 2&3 Restart/Operational Lessons Learned • System component integrity wall thickness measurements	• Complete replacement with material changed from carbon steel to stainless steel (316/316L) to eliminate corrosion materials in the system and drywell. • All new valves installed
Reactor Building Closed Cooling Water 070	Reactor Building	DCN 51195	• Units 2&3 Restart/Operational Lessons Learned • System component integrity wall thickness measurements	• Replaced "A" & "B" Heat Exchangers with upgraded heat exchanger tube material. Entire heat exchanger replaced in lieu of retubing existing heat exchanger due to cost considerations.
Reactor Core Isolation Cooling 071	Reactor Building	DCN 51196	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Steam trap drain line replacement with 2-1/4% Cr. materials to prevent FAC • In lieu of refurbishment, replaced several large bore valves
High Pressure Coolant Injection 073	Reactor Building	DCN 51198	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Steam trap drain line replacement with 2-1/4% Cr. materials to prevent FAC • In lieu of refurbishment, replaced several large bore valves

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Residual Heat Removal 074	Drywell	DCN 51151	• IGSCC Issues	• Complete replacement with IGSCC resistant 316NG materials • Large bore valves refurbished
Core Spray 075	Drywell	DCN 51152	• IGSCC Issues • System component integrity wall thickness measurements	• Complete replacement with IGSCC resistant materials • Stainless steel material (304) was replaced with a high toughness carbon steel material A333, Gr. 6 • Large bore valve materials are stainless steel
Core Spray 075	Reactor Building	DCN 51200	• IGSCC Issues • System component integrity wall thickness measurements	• Very short section of stainless steel material (304) was replaced with a high toughness carbon steel material A333, Gr. 6 to eliminate a weld overlay

Table 2 – Browns Ferry Unit 1 Restart Project - Piping System Inspections		
Program	**Inspection Classification**	**Inspection Scope**
Reactor Pressure Vessel (IVVI)	• Component Integrity Inspections will be performed • Partial IVVI examinations were conducted in 2001to determine any major conditions. • The visual examinations will be completed after vessel flood up and water clarity has been re-established.	• BWRVIP-18 - Core Spray • BWRVIP-25 - Core Plate • BWRVIP-26 - Top Guide • BWRVIP-27-A - Standby Liquid Control • BWRVIP-38 -Shroud Support • BWRVIP-41 - Jet Pump • BWRVIP -47 - Lower Plenum (CRD, Incore) • BWRVIP-48 Vessel Attachment Welds • BWRVIP-49-A Instrument Penetrations • BWR-74-A - Reactor Pressure Vessel (license renewal only) • BWRVIP-76 - Core Shroud
Section XI Re-Baseline Inspections	• IWB Class 1	• 25% of piping welds accessible without removal of supports or permanent features for those systems not being replaced. Selection basis: system distribution, welds that had not been examined in the 1st Interval • 100% of component supports • RPV vessel head and longitudinal shell welds • 100% bolting • 100% accessible RPV interior and interior attachments (VIP)
	• IWC - Class 2	• 7.5% sample of welds on each system • 100% component supports
	• IWD- Class 3	• 100% component supports including attachments

BROWNS FERRY UNIT 1
NUCLEAR PERFORMANCE PLAN SPECIAL PROGRAMS

The Browns Ferry Nuclear Plant (BFN) Nuclear Performance Plan Special Programs are subdivided into two categories: those that require completion prior to Unit 1 restart and those that were completed for all three BFN units before the start of the Unit 1 restart project. The Special Programs that require completion prior to Unit 1 restart were evaluated and designed for Extended Power Uprate and License Renewal requirements which were applicable to each structure, system or component.

Special Programs to be completed prior to Unit 1 restart:

- Component and Piece Part Qualification
- Configuration Management – Design Baseline and Essential Calculations *
- Containment Coatings
- Electrical Issues
- Environmental Qualification
- Fire Protection – Appendix R
- Flexible Conduit
- Fuse Program
- Instrument Sensing Lines
- Intergranular Stress Corrosion Cracking (IGSCC)
- Moderate Energy Line Break *
- Restart Test
- Seismic Design Program

** - TVA has notified NRC that the Unit 1 program has been completed.*

Special Programs considered closed before the Unit 1 restart project started:

- Heat Code Traceability
- Secondary Containment Penetrations
- Thinning of Pipe Walls (Bulletin 87-01)
- Welding
- Probabilistic Safety Assessment (Generic Letter 88-20)

A summary of each special program that requires completion for Unit 1 restart is provided below.

COMPONENT AND PIECE PART QUALIFICATION

The objectives of this program are to:

- Verify that previously environmentally qualified equipment was not degraded on Unit 1 through the use of spare and replacement parts, and
- Have programs and practices in place to ensure that previously seismically and environmentally qualified equipment, and any equipment qualified by other programs in this restart effort, will not be degraded in the future through the use of spare and replacement items.

To accomplish these objectives for Unit 1, the following tasks will be performed for any EQ equipment not replaced during Unit 1 recovery:

- Review of maintenance history to identify activities that included replacement of safety related components,
- For any replacement item that has not been qualified as part of the EQ Program, an evaluation will be completed to determine qualification,
- Evaluation of inventoried commercial grade spare parts to assure their subsequent use will not degrade previously qualified equipment, and
- Unit 1 procedures and processes will include all of the work developed as part of the Unit 2 and 3 restart efforts to ensure current and future qualification of components and piece parts.

CONFIGURATION MANAGEMENT – DESIGN BASELINE AND ESSENTIAL CALCULATIONS

The Browns Ferry Design Baseline Verification Program (DBVP) was established with the objective of reestablishing the plant design basis and to evaluate the plant configuration. This DBVP reestablishes the plant design basis. The system boundaries were selected by determining systems and portion of systems used to mitigate design basis events, as described in Chapter 14 of the Updated Final Safety Analysis Report (UFSAR), provide for safe shutdown and any other safety related function. Design basis changes resulting from later programs such as extended power uprate, Generic Letter 89-10, 10 CFR 50.49 Environmental Qualification of Electrical Equipment and the license renewal program have been addressed under separate programs. The DBVP evaluations ensure:

1. Plant configuration satisfies the design basis.
2. Configuration of systems and components within the scope of the DBVP is supported by engineering analysis and documentation.

3. Plant configuration is in conformance with TVA's licensing commitments.

This was accomplished by four major tasks, as follows:

1. Establish Design Basis Input

   This task consisted of developing a series of key products, which ultimately formed the design bases of the plant. These items are:

   - Databases containing licensing commitments made throughout the life of the plant and design requirements necessary to achieve safe shutdown.

   - Design Criteria Documents developed from the above database and input from senior engineers were used to establish the required configuration.

   - A Safe Shutdown Analysis (SSA) of the FSAR requirements for identification of accidents, abnormal operational transients, and special events from which the plant must be able to achieve safe shutdown.

   - Essential calculations needed to verify the adequacy of the design within the safe shutdown boundary.

   - Test requirements which verify system capability using Baseline Test Requirements Documents.

   Much of the data gathered in the Unit 2 and 3 efforts was applicable to Unit 1 and, in fact, most of the products identified above were built largely by revising Unit 2 and 3 documents to be Unit 1 specific.

2. Establish Configuration

   This task was accomplished by implementing the following activities:

   - Walkdown of systems within the DBVP boundary to verify functional configuration. Flow diagrams were evaluated and corrected as required based on the walkdown results. Review of input from walkdowns for other programs not related to DBVP, such as EQ and Appendix R was used to verify the correctness of associated drawings.

   - Verification of control/single line/elementary/schematic diagrams has been partially accomplished through a review of existing documents and walkdowns. Where walkdowns were not performed, the diagrams were modified via the Design Change Notice (DCN) process. Implementation of the Unit 1 Restarte DCNs will provide configuration control prior to restart of Unit 1. Final verification will be accomplished by the restart test program.

- Testing performed during the Restart Test Program to ensure specifications verify required functions.

3. Evaluate Configuration

This task consisted of the following activities:

- Develop as-built drawings based on field walkdowns. These are known as the Configuration Control Drawings (CCD). Review of CCDs to ensure they accurately depicted system functions, and differences dispositioned.

- Review of Corrective Action Program documents to ensure adequate corrective actions were taken.

- Evaluation of other programs to ensure the appropriate corrective actions are incorporated into the applicable DCNs from the programmatic reviews such as EQ, Appendix R, and Generic Letter 89-10. This effort is not a part of the DBVP scope but is performed in conjunction with it.

- Evaluation of unimplemented or partially implemented changes for significance with respect to design basis.

- Units 2/3 DCNs were used as a basis to formulate the scope of effort required to return Unit 1 to service. The Units 2/3 DCNs were used as a representation of the current status of an operating BFN unit. It was the intent of the Unit 1 restart effort to make Unit 1 functionally identical to the operating units so that they would have a common design basis. This effort is not a part of the DBVP scope but is performed in conjunction with it.

- Evaluation of components to ensure they perform their design basis function.

- Evaluation of test specifications to ensure that tests adequately verify specified characteristics.

4. Issue Design Output

This task included issuing the following documents:

- Configuration Control Drawings.
- Calculations.

As in Unit 3, the DBVP for Unit 1 utilized a consolidated approach which was completed prior to restart. NRC was notified of the Unit 1 program completion on May 19, 2005.

CONTAINMENT COATINGS

This program will establish the condition of the qualified protective coating on the surfaces of the drywell and torus and quantify the amount of unqualified coatings on equipment or structures inside primary containment.

The presence of unqualified coatings is established through a combination of walkdowns, testing and review of contracts, vendor manuals and work orders. All applicable coated equipment and structures will be evaluated. Existing coatings that do not qualify must be either removed, reduced in film thickness to less than 3 mils or accounted for in the Uncontrolled Coating Log.

The condition of qualified coatings inside primary containment is established through walkdowns by qualified inspectors. The condition is recorded and unacceptable areas are repaired.

Torus coatings below the immersion area were sandblasted to clean metal and a new qualified coating system applied. Torus coatings above the immersion area have been repaired.

ELECTRICAL ISSUES

The Electrical Issues Program consists of seven individual programs. These programs are:

- Cable Ampacity
- Cable Installation
- Cable Separation
- Cable Splices
- Flexible Conduit
- Fuse Program
- Thermal Overloads

Each of these is described below.

Cable Ampacity

In 1986 an audit revealed inadequacies in TVA's electrical design standards, creating the potential for undersizing of safety related cables at Browns Ferry. TVA developed a new standard, "Ampacity Tables for Auxiliary and Control Power Cables", which corrected all inadequacies. This standard addressed all ampacity requirements of Appendix R. TVA used this standard to determine the extent of non-conformance and to implement corrective action for any non-conformance on Units 2 and 3. This program ultimately assured that cables at Browns Ferry Units 2 and 3 are not utilized above their rated temperatures and will be capable of performing their intended safety functions under normal, abnormal and accident conditions.

The replacement of V4 (480V power cable) and V5 (4160V) cables on Units 2 and 3 was minimized and the use of original cable maximized through sampling and statistical analysis, aging analysis, and ampacity calculations utilizing tray loading profiles. Assumptions were made that Unit 1 cables included in trays containing primarily Unit 2 and/or Unit 3 cables will not be energized. Approximately 3500 V3 (120VAC or 250VDC) cables were reviewed during Unit 2 restart, with none requiring ampacity evaluations. For Unit 1, the intent is to abandon in place all V4 and V5 cable installed in tray and install new cable end to end. V4 and V5 cables in conduit will be evaluated and replaced, as determined by evaluation. Unit 1 cables previously evaluated in support of Units 2 and 3 restart will be excluded from these considerations.

Based on the results of the Unit 2 evaluation, Unit 1 V3 cables will not be evaluated.

Cable Installation

Based on concerns that had previously been identified at the Sequoyah Plant, TVA identified several potential installation issues that would be evaluated on Unit 2 to assure the adequacy of cable installations. These included sidewall pressure, jamming, pullbys, vertical conduit, cable bend radius and pulling cable through flexible conduit and condulets. Since the program established at Sequoyah demonstrated the adequacy of TVA installation practices in maintaining the integrity of cables during installation, it was used as a baseline for the Unit 2 evaluation. This evaluation included the following activities:

- Comparison of the cable installation requirements at Browns Ferry with those throughout the industry, including Sequoyah, during the period of Browns Ferry's construction,

- Comparison of the safety-related cable and conduit materials used at Sequoyah and Browns Ferry, and

- Plant walkdown inspections to assure the cable installation practices and quality of installed cables.

Three additional issues were identified during the Unit 2 recovery effort. There were use of conduits as pull points for large 600 volt cables, missing conduit bushings, and Brand Rex cables. The Unit 2 tests and inspections resulted in limited replacement and concluded that Unit 2 was successfully enveloped by the Sequoyah program, with two exceptions; bend radius and vertical supports. These two installation issues were evaluated separately, largely found acceptable and limited corrective actions taken.

The Unit 3 program included a review of issues evaluated for Unit 2, application of lessons learned, confirmatory walkdowns in lieu of the evaluation program identified above, and focused evaluations based on Unit 2 results. The Unit 1 program will be the same as the Unit 3 program.

Cable Separation

Cable separation problems were first identified in 1988 and TVA subsequently established a program to determine the extent of separation non-conformance, and to take the necessary corrective action. Discrepancies were grouped in the following categories:

- Non-divisional circuits associated with more than one safety division,

- Cables with an IE or IES suffix, or Q-List cables that were designated as either divisional or nondivisional and with questionable raceway routing, and

- Inaccuracies in cable and conduit schedules.

For Unit 2, TVA first validated the cable and conduit schedule, then identified populations of cables with one of the above discrepancies. Cable separation criteria were developed and the populations were evaluated against the criteria. Corrective actions were implemented as required.

The Unit 3 program applied lessons learned from the Unit 2 program in the following manner:

- Applied an integrated walkdown approach,
- Used Unit 2 programs which evaluated Units 1 and 3 cables, and
- Evaluations were performed concurrent with Q-List development.

The Unit 1 separation scope will be performed in accordance with the Unit 3 criteria and implementation precedent.

Cable Splices

Based on concerns about improper installation of heat-shrinkable tubing over electrical splices and terminations, TVA initiated a program consisting of two elements:

- Revision of the General Construction Specification G - 38 and standard drawings to address installation problems.

- Walkdowns to identify and inspect all 1E cable splices and terminations located in harsh environments. Splices which did not conform to standards were replaced.

For Unit 1, the scope of the splice program includes all 10 CFR 50.49 cables and all safety related cables below flood elevation. These will be identified via the EQ program and walkdowns. The total cable population will be walked down to locate splices; all of which will be replaced.

Flexible Conduit

Original construction specifications at Browns Ferry did not adequately address the requirements for minimum and maximum flexible conduit lengths to allow for thermal and seismic movement. The current Construction Specification, G-40, defines the minimum conduit length for accommodating thermal and seismic movement.

For Units 2 and 3 TVA inspected all flexible conduits attached to electrical equipment covered by 10 CFR 50.49 to verify that the lengths of flexible conduit satisfy G-40 requirements for accommodating thermal and seismic movement. Conduits not satisfying G-40 were documented and technically justified as acceptable, or reworked to satisfy requirements. For unit 1, conduits will be inspected during the walkdown of 10 CFR 50.49 cables. The results will be documented and evaluated, with the disposition documented.

Fuse Program

The Browns Ferry fuse substitution list in place prior to Unit 2 recovery conflicted with the fuse substitution list contained in the Design Standards revised just prior to the recovery effort. Thus, there was insufficient evidence that installed fuses would provide adequate overload protection for Unit 2. TVA's program to address this issue included the following steps:

1. Revise the Browns Ferry fuse substitution program control document to reflect the appropriate standard.
2. Perform calculations to the revised standards to specify and tabulate correct fuses for each application.
3. Perform walkdowns to determine and document installed fuses and compare with tabulations.
4. Resolve and document inadequate fuses based on comparison.
5. Replace fuse ratings on design drawings with fuse identifications.

For Unit 1, the fuse tabulation will be developed from existing common Unit 1, Unit 2 and Unit 3 tabulations. Unit 1 fuses will not be included in the walkdown. Instead, DCNs will be issued to identify required fuses and replace applicable Unit 1 fuses, as required, based on calculations.

Thermal Overloads

TVA identified the fact that design drawings for 480V ac and 250V dc motor control centers (MCC) did not specify thermal overload ratings for the heaters which provide electrical protection for the motors. The Thermal Overload (TOL) Program for Units 2 and 3 consisted of the following activities:

- Developed criteria for sizing the TOL heaters for MCC circuits.
- Performed walkdowns of the MCCs to determine and document the installed TOL heater element sizes and nameplate data for each load.
- Prepared calculations using revised design standards (criteria) to specify the appropriate heaters for each application.
- Reconciled walkdowns with calculations.
- Replaced or adjusted improperly sized heater elements.
- Updated drawings to reflect current heater elements.

The Unit 1 program will use the same approach, utilizing existing Unit 2 and 3 calculations and worksheets. All Unit 1 TOLs will be replaced based on calculations.

ENVIRONMENTAL QUALIFICATION

The Code of Federal Regulations requires that equipment used to perform a necessary safety function is capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. TVA determined that there was a systematic lack of qualification documentation for a significant part of the required equipment. TVA also determined that the significance of the problems and the programmatic nature of the root causes required not only a program that demonstrated compliance to 10 CR 50.49 for all required equipment, but the development of an EQ program infrastructure.

To demonstrate compliance, TVA committed to subjecting all equipment within the scope of 10 CFR 50.49 at BFN to new review, which was independent of previous EQ efforts. TVA will use the infrastructure developed for the Units 2 and 3 restart efforts to perform these reviews for Unit 1. The following items or actions will support this effort as well as the long-term qualification of equipment for Unit 1:

- Existing EQ program procedures provide the basis for maintaining EQ over the operating life of the plant.

- Consistent documentation requirements, including the list of all electrical equipment located in harsh environments and required to function after an accident, and the EQ Documentation Package provide documented evidence of the qualification of equipment for its specific application and environment.

- Incorporation of EQ maintenance elements into ongoing maintenance activities for equipment.

- Training of EQ personnel on specific EQ related subjects.

The elements of the EQ review effort for Unit 1 include the following:

1. The 50.49 List

   This list will include electrical equipment located in harsh environments and required to function after an accident. This list is developed through the following steps:

   a. A systems analysis to determine for each Design Basis Accident (DBA) those equipment items ("end devices"), which must either operate or "stay-as-is", to ensure completion of a safety related function.

   b. For each end-device, a review of drawings is conducted to identify those ancillary devices and cables required to operate or maintain electrical integrity to ensure completion of the end-device's safety related function. The end-device and the items added by this review comprise the Component Master List (CML).

   c. The CML is reduced by performing a failure analysis which eliminates those components whose failure would not prevent achievement of the required safety action.

   d. The elimination of equipment from the list that is located in a mild environment.

   e. An evaluation to determine if any components on the CML are located in a harsh environment, but do not experience it when they are required to function, and thus can be eliminated.

2. The EQ Documentation Packages (EQDPs)

   TVA has a documented process, including a detailed checklist, to direct the completion of documented evidence of qualification of equipment for its specific application and environment. A package will be developed for each Unit 1 equipment type.

The package will include:

- Items comprising the equipment type,
- Checklist for evaluation of qualification,
- Analysis and justification of qualification,
- Qualification documents,
- Field verification data, and
- Qualification Maintenance Data sheets.

These packages will be subjected to a systematic verification process.

3. Collection of all data necessary to support EQ activities including design drawings, purchase contracts, vendor information, test reports and field verification checklists.

4. Long-term support of equipment qualification via maintenance, training, warehouse inventory / spare parts and modifications / installations.

The implementation of the Unit 1 EQ program will be performed in accordance with the Units 2 and 3 criteria and implementation precedents.

FIRE PROTECTION – APPENDIX R

The Fire Protection Improvement Program for Unit 2 included the following elements:

- Compliance to 10 CFR 50 Appendix R, and
- Plant Fire Protection Program, which addressed:
  - Organization and staffing
  - Fire protection procedures and administrative controls
  - Evaluation of compliance with regulatory and industry standards and corrective actions to address deviations

A report on improvements to the Browns Ferry Fire Protection Program to satisfy Appendix R requirements was submitted by TVA in April 1988. The report contained the "Fire Protection Plan for the BFN", the "10 CFR 50 Appendix R Safe Shutdown Analysis", and the Fire Hazards Analysis for Fire Areas and Zones in the BFN". During the restart effort, TVA proceeded with implementation of the modifications for compliance, based on the submittal. The modifications included items in the following areas:

- Fire detection,
- Fire suppression,
- Compartmentation,
- Circuit modifications,
- Cable modifications,

- Breaker and fuse upgrades,
- Addition of main steam relief valve backup air supply,
- Battery backup power supply for communications, and
- Emergency lighting

The Unit 1 scope will focus on these evaluations and the modifications necessary to gain compliance with Appendix R and NFPA standards. The major tasks that make up this scope are:

- Preparation of a Fire Hazards Analysis for Unit 1,

- Preparation of a Unit 1 Baseline Appendix R Analysis,

- Performing modifications necessary to be in compliance with regulations and standards,

- Preparation of Safe Shutdown procedures utilizing existing procedures already in-place for Units 2 and 3, and

- Preparation of a Site Fire Protection Report to include Unit 1.

The intent of these activities is to achieve compliance with Appendix R while maintaining commonality between the units.

INTERGRANULAR STRESS CORROSION CRACKING (IGSCC)

The objective of the IGSCC Program is to address all of the instances of Intergranular Stress Corrosion Cracking with long term resolutions. The scope of IGSCC susceptible piping and components was established by the guidelines of GL 88-01 and includes:

- Reactor Recirculation from the recirculation inlet and outlet nozzles to the connections with residual heat removal,

- Residual Heat Removal (RHR) from the recirculation system to the first isolation valve outside of the drywell penetration,

- Reactor Water Cleanup (RWCU) from its connection to the RHR system to first isolation valve outside of the drywell penetration,

- Core Spray from the core spray inlet nozzles to the drywell penetration, including the core spray inlet safe ends,

- Recirculation Inlet Safe Ends, and

- Jet Pump Instrumentation Safe Ends.

The head spray systems are not included, because they will be removed from Unit 1 before plant startup. The Unit 1 program is implementing the following mitigating actions:

- Full replacement of all IGSCC susceptible piping, safe ends and penetrations with resistant material,
- *Stress improvements applied to new weldments, and*
- Implementation of hydrogen water chemistry

Additionally, TVA has already replaced all jet pump beams on Unit 1 and will inspect shroud head bolts, which have shown evidence of cracking at Browns Ferry and other BWRs, and replace them, as required.

INSTRUMENT SENSING LINES

The program to qualify Unit 2 and common instrument sensing lines was developed to address concerns with regard to slope, physical separation and quality classification relating to material control. The Unit 2 approach involved scoping out instruments and their associated sensing lines based on System Requirements Calculations, FSAR Chapter 14, Emergency Operating Instructions, equipment related parameters and maintenance history. Safety significance and equipment vulnerability screening criteria were developed using this information. The lines selected based on these criteria were walked down and evaluated using established acceptance criteria. Lines not satisfying these criteria were evaluated via calculations, and those not qualifying were modified. Reviews and assessments identified no specific cases of inadequate physical separation and this was supported by all Unit 2 reviews performed. Additionally, there were no specific cases of inadequate quality classification identified and the reviews supported this as well. Based on these results and on the review of physical plant, criteria documents and design specifications for Unit 3, the Unit 3 program reviewed instrument sensing lines only for slope problems. The Unit 1 restart program will use the same approach.

MODERATE ENERGY LINE BREAK

Moderate Energy Line Breaks (MELB) are those breaks in liquid systems that are not high energy lines, but if they break could cause damage to safety related structures, systems or components due to the effects of flooding. A MELB evaluation has been performed for Unit 1 using the same methodology used for the Units 2 and 3 MELB evaluations. The Unit 1 MELB evaluation also considered design changes made for the planned Extended Power Uprate. The conclusions of the MELB evaluation were that

BFN Unit 1 conforms to the original licensing basis and the existing flooding studies and protective measures are adequate.

TVA notified NRC on June 25, 2004, that the Unit 1 MELB program had been completed.

RESTART TEST

The Restart Test Program is conducted to ensure that plant systems are capable of meeting their safe shutdown requirements. The elements of the program are:

1. Review of documentation relating to operating, maintenance and modification history, as well as vendor recommendations to provide key input to development of system test requirements.

2. Development of baseline test requirements (BTRDs) for each required plant system to define scope of testing required, identify additional testing requirements beyond routine testing, and to identify requirements for tracking testing and evaluating test results.

3. Development of Test Instructions for each required system to identify specific testing to verify system performance consistent with specification requirements, and to track and verify completion of each test and evaluate results. These instructions, as well as the specifications, will work within the framework of existing procedures.

For Unit 1, administrative controls will be used to ensure that the status of operating units is considered during planning and scheduling of restart tests, as was done for the Unit 3 restart tests.

SEISMIC DESIGN PROGRAM

Two of the issues that comprise the seismic design program were closed for all three BFN units as part of the Unit 2 restart effort. These were secondary containment penetrations, whose physical work was completed due to its common nature, and miscellaneous civil issue, which was combined with other programs. The remaining programs that must be completed to support Unit 1 restart are:

1. <u>Torus Modifications</u> includes a re-inspection of torus attached piping and modifications to torus and torus internal structural components to verify that design drawings reflect the as-installed configuration. Discrepant items are identified, evaluated, and modifications performed as required.

2. Large Bore Piping and Supports (Bulletins 79-02 and79-14) involves completing the verification of as-built versus as-designed piping and supports. It includes field walkdowns of existing piping configurations, analysis to the current design criteria, and the required modifications to existing piping and supports to establish compliance with the design criteria.

3. Cable Tray, Conduit Supports, and the Seismic II Over I / Water Spray programs address seismic qualification of the supports using the Generic Implementation Procedure developed by the Seismic Qualification Utility Group (SQUG).

4. HVAC Ductwork involves inspection of ductwork for attributes important to seismic qualification and analyzing them against design criteria to ensure as-built versus as-designed discrepancies are reconciled.

5. Small Bore Piping and Instrument Tubing programs are required to address concerns about design criteria, incomplete support details and missing calculations for piping, and the need to consider thermal stresses for tubing. The resolution methodology for both piping and tubing on Units 2 and 3 included identifying generic attributes, performing rigorous analysis of 10 - 15% of the piping within the safe shutdown boundary to verify the attributes, and performing walkdowns based on these attributes. Outliers were identified, evaluated and modified when design criteria were not met. The criteria and implementation precedent used for Unit 3 will be used for Unit 1.

6. Control Rod Drive (CRD) Hydraulic Piping program addresses a concern raised about the adequacy of CRD insert and withdrawal piping and piping supports to carry design basis loads. Units 2 and 3 tubing were qualified via conservative bounding calculations to current design criteria, supported by confirmatory evaluations. Unit 1 tubing are being qualified using the same bounding calculations.

7. Drywell Steel Platform - Concerns addressed by this program were:

   - As-built versus as-designed discrepancies,
   - Structural behavior not completely evaluated or documented, and
   - Steel had not been evaluated for loads added since original design.

   The Unit 1 drywell program will use the methodology and design criteria developed for Units 2 and 3.

8. Miscellaneous Steel program addresses configuration problems on miscellaneous framing installed throughout the Reactor Building during construction. The framing supports large bore piping and other commodities. The Unit 1 program will utilize the same design criteria, methodology and analysis tools used on Units 2 and 3.