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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 3, 2004

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY,

NOVEMBER 3, 2004

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 1:30 p.m., Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA	Chairman
RICHARD S. DENNING	Member
GRAHAM M. LEITCH	Consultant
VICTOR H. RANSOM	Member
WILLIAM J. SHACK	Member
JOHN D. SIEBER	Member
GRAHAM B. WALLIS	Member

ACRS STAFF PRESENT:

CAYATANO SANTOS

OTHER NRC STAFF PRESENT:

KENNETH C. CHANG, NRR

CAUDLE A. JULIAN, Region II

PT KUO, NRR

SAM LEE, NRR

TILDA LIU, NRR

ALSO PRESENT:

JAN FRIDRICHSEN, Southern Nuclear Operating Company

PARTHA GHOSAL, Southern Nuclear Operating Company

WAYNE LUNCEFORD, Southern Nuclear Operating Company

MICHAEL MACFARLANE, Southern Nuclear Operating Company

CHARLES PIERCE, Southern Nuclear Operating Company

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

1:30 p.m.

DR. BONACA: Good afternoon. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee. The members in attendance are Richard Denning, Victor Ransom, Steven Rosen, William Shack, Jack Sieber, and Graham Wallis. ACRS consultant Graham Leitch is also present. Cayatano Santos of the ACRS staff is the designated federal official for this meeting.

The purpose of this meeting is to discuss the license renewal application of the Joseph M. Farley Nuclear Station Units I and II. We will hear presentations from the NRC Office of Nuclear Reactor Regulation, the representatives of the Southern Nuclear Operating Company.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on October 5, 2004.

We have received noted incumbent's request for time to make oral statements from members of the public regarding today's meeting. The 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 themself and speak with sufficient clarity and volume so they made be readily heard.

We will not proceed with the meeting. I call upon Mr. Kuo of the Office of Nuclear Reactor Regulations to begin.

DR. KUO: Thank you, Dr. Bonaca. Good afternoon. For the record, I'm P.T. Kuo, the Program Director for the License Renewal and Environmental Impacts Program. On my right is Dr. Sam Lee who is the Second Chief for Project Management Section. To my extreme right is Tilda Liu who is the Senior Project Manager for this project.

As you indicated, today the staff will brief the committee on the Farley License Renewal Application Review. You may recall that Farley is the first power plant that uses what we called audit review process for the Aging Management Program parts

that are consistent with GALL, consistent with our previous staff approved positions.

This presentation will have three parts. The first part will be led by Tilda who will discuss the general review of the whole project. And the second part will be the inspection review that will be lead by Caudle Julian from Region II. He is the team leader of the inspection. And then the third part is audit review process led by Dr. Kenneth Chan who is a team leader for the audit team.

Because the audit process is new and this is the first plant, I would really like to say a few words specifically about the audit process. As you may recall, we have briefed the committee some time ago that we generally have a team that consist of about seven to 10 people that include both the staff members and contractors with different enduring disciplines that includes material structures, mechanical, and electrical.

They will stay on site about two to three times during the audit. Each time is about a week. They stay on site, perform their review. When they come back they prepare the report, address all the issues that they have discussed with the applicant.

We believe this process so far as been

very successful. From the feedback we got from the industry, I think all the feedback appears to be pretty positive. We applied this process to all our recently received applications. So for that purpose we really appreciate if you have any comments on this process and we would like to have them.

MR. LEITCH: PT, one of the measures of success was going to be, at least in part, the number of RAIs. Did this result in less RAIs than previous?

DR. KUO: Well, we have been successful to some extent. We have not reached the degree that we really like to see. For Farley I think we had about 186 or 187 RAIs. 153, okay. That's even better. Previously we had between 200 and 300. The reduction is not as significant as I would like to have but because this is the first audit plan, I give it some time. I would expect that the RAIs will go down somewhat more.

MR. LEITCH: I'm a little confused. I read a report that was about in the April 2004 time frame, the result of a team. I think it was led by Jimi Yerokun that looked at the process and looked for ways to improve the process. They had a number of recommendations, coordination, communication, and some improvement to the flow of the process. Is this a

result of that report or is there still some further improvement to the process based on the recommendations of that report? Are you familiar with the report I'm speaking of?

DR. KUO: Yeah, I know. They are separate. Jimi Yerokun's assessment team was to assess the effectiveness of these scoping and screening part of review. That is being done by another division. The process that I'm talking about now is the process that deals with the Aging Management Program.

MR. LEITCH: Okay. Is there a plan to implement the recommendations, or at least consider the recommendations that were in that April report?

DR. KUO: The recommendations are being implemented right now.

MR. LEITCH: Okay.

DR. KUO: Actually, the Browns Ferry -- I'm sorry, Brunswick will be the first implementation. For instance, at the end of the recommendation we talk about the 54.4(a)(2) issue that would be probably better to be done by the region because they are at the site. They look at the spacial arrangement of all the hardware.

MR. LEITCH: Largely dependent on spacial.

DR. KUO: Right. That would be done by the region for Brunswick. We are, of course, improving our coordination and communication among our different groups.

DR. BONACA: You were asking about this report, our opinions. This is the report that was the audit review of the report. Right?

DR. KUO: Right.

DR. BONACA: Okay. I think it's a very good audit actually. I think it was very insightful. For a reviewer such as me complicated life because it was repetition within the SER and this report so it wasn't clear how you incorporated. I was sure that you did but I had to look at it separately. The question I would have is for the future are you planning to still have a separate report like this or are you trying to document it within the SER?

DR. KUO: No, separate audit report. Every audit we will produce a report.

DR. BONACA: But you're reflecting these insights already also in the SER because you are referring to that.

DR. KUO: Right.

DR. BONACA: So you plan to maintain it as an audit document.

DR. KUO: Yes, sir.

MR. LEITCH: I had kind of the same question as Dr. Bonaca. I had the audit and review report before I had the draft SER and I reviewed it and found it very helpful, by the way. I thought it was well organized, easy to follow. Perhaps -- not perhaps, it definitely was somewhat repetitive but it was easy to follow and navigate one's way through. I sort of thought when I got the draft SER what I might find is this almost as a section in its entirety just inserted in the SER because it did seem to be repetitive to a lot of the information that was in the SER.

DR. KUO: Some of it may be repetitive but it was purposely done. We wrote the report with the mind that this is going to be transferred to the SER. The audit team is responsible for about 50 to 70 percent of the review consistent with GALL and previously approved staff positions.

If after the audit report if we have to write another SER, that is just too consuming and not the efficient use of time. We prepared the audit report with the mind that some of the content could be transferred to SER so that we don't have to spend time to just simply write in this SER. But they did report

it has more details in it.

MR. LEITCH: I was thinking of just further improvements in the efficiency of the process. It seemed to me that this could almost be lifted and become the major part of the SER.

DR. KUO: Maybe. We are constantly looking at it and see if we can still improve on it. If it turns out that we really don't have to prepare an audit report and just go into the SER, we will do that but what I'm afraid of is that some of the details that now is currently in the report will somehow not be seen.

DR. BONACA: Yes. Let me just say that this has nothing to do with Farley specifically, of course. For the purpose of a reviewer, I go in with very specific operating interest in experience for this plant, any plant, what they have gone through and the applicable operating experience from other sites and plants.

Second, the site characteristics, which are unique to that site, which should make for the kind of challenges there may be to the buried cable, buried structures, the licensee's actions to improve the plant, to maintain it, all those things. The more paper we get, the more difficult it is to focus on the

same issues because that's really the same issues. To the degree to which it can be streamlined by including one document into the other, I really wish you well. I would like you to attempt it.

DR. KUO: Thank you.

DR. BONACA: Anyway, I don't want to criticize the report. I thought it was an excellent audit and, in fact, it provided a lot of good information about the aging management problems.

DR. KUO: Thank you.

DR. SHACK: On the other hand, let me just say I thought the SER was very good. This was really one of the best SERs that we've seen on the license renewal process. I thought it was very well organized that a person reviewing the process could go through and get all the information in a rather compact form.

DR. BONACA: It even had sections separations, tabs.

DR. KUO: Thank you very much. Tilda will be happy to hear that.

DR. BONACA: Okay. Well, with that --

DR. KUO: With that I would call the Farley Southern Services to make a presentation first and then the staff briefing will follow.

MR. PIERCE: My name is Charles Pierce.

I'm the manager for the License Renewal Program for Southern Nuclear, and specifically for Farley. Jan Fridrichsen, who is the license renewal licensing manager for us, is now walking up to the front to make his presentation. To my right now is Mike MacFarlane who is our license renewal technical manager for Farley as well.

I'm just going to make one or two quick remarks. One, I do appreciate the opportunity to speak to you all today. I do think that the NRC's review has been very, very comprehensive. I think consistent with the GALL process that was developed has been a factor in that. I think if we go through that you'll see how it has worked to improve the overall process.

As another note, I've been working in license renewal now since 1994. I'm an old timer here. I've been working in licensing since the early '80s off and on in various projects. Just as a point of note, I do find that on the license renewal project for the NRC that the NRC has been very progressive in considering changes both internally in the industry and moving ahead with those changes.

I think you see that with things consistent with GALL issues that we have today, and

overall improving the process over time. I think that speaks to their efforts and I'm glad to see that. I think there are other changes that are being considered now that I think would further improve the process as well. Thank you very much.

MR. FRIDRICHSEN: Good afternoon. My name is Jan Fridrichsen and I'll be conducting our part of the presentation. Just to give you a rather quick introduction of what we're going to talk about, we'll talk a little bit about the application and its background. Talk a little bit about the description of Farley Nuclear Plant and features of the plant. A little bit of our operating history. Talk a little bit about the scoping process that we went through for developing our application.

How we applied the GALL to developing our application. We understand there's some interest in the commitment process and how we manage commitments and I'll have a little discussion on that and then touch on some of the basic industry issues that are of note before us this day and give you a little briefing on what Farley is doing on those.

We submitted the application on September 12, 2003. Our original license exploration dates are in 2017, 2021 for Units I and II respectively. The

application itself was a new process. It consisted of -- it had to be consistent with GALL audits. It was the first of its kind.

We had three inspections or audits and it was focused on assessing our determinations consistent with GALL adequate for the staff. We felt like, as was commented before, it was a very successful process. A lot of information was brought forward and a lot of clarity was brought to the process.

What is Farley Nuclear Plant? It's a three-loop, Westinghouse pressurized water reactor. We had dual engineering services on the construction of the plant. Bechtel was the interface between Westinghouse and they did the engineering of the Westinghouse systems and their integration plant.

Then Southern Company Services was our power generation end of the plant, term building and outside structures. They engineered that. Initial operations, Unit 1 in 1977 and Unit 2 in 1981. We generate approximately 910 megawatts per unit.

MR. LEITCH: Jan, perhaps this would be a good time to raise this question while you have the photograph there. I have a little trouble understanding just what the general circulating water versus safety service water, essential service water

or whatever you call it, is. Is there a lake some place? In other words, I couldn't quite understand. All the circulating water system and so forth is not in scope. I guess that's primarily for the condensers. Could you just talk about the essential service water?

MR. FRIDRICHSEN: Okay. Not seen in that photograph but the supply source water for plant Farley is the Chattahoochee River. It's on the Georgia/Alabama border. From that we pump to the seismic, safety-related service water pond. From that pond we supply essentially all the plant water needs, safety-related needs and the makeup to the circulating water system.

MR. LEITCH: Okay, but the circulating water itself.

MR. FRIDRICHSEN: Well, it comes from the service water system supply to the circulating water system. Our service water, for example, our supply flow per unit is about 40,000 gallons a minute and our typical makeup to the circulating water system is about 10,000 gallons a minute so once through is approximately 30,000 gallons of water.

MR. LEITCH: So this pond is in scope then?

MR. FRIDRICHSEN: Yes.

MR. LEITCH: And the pumps that feed the water into the pond are not?

MR. FRIDRICHSEN: That's correct.

MR. LEITCH: Okay. I understand. Thank you. I saw the picture but --

MR. FRIDRICHSEN: To give you a little bit of information relative to plant performance for Farley over the last five years, this graph represents our capacity factors for Unit 1, Unit 2 outage durations. You'll notice in the 2000/2001 time frames we have asterisked data. Those two years we replaced steam generators on each unit so the outages were a little longer. Radiation exposure was a little higher.

If you'll notice, though, as we go out into 2002/2003 the exposure information or the exposure data is extremely low. We have a very aggressive dose program at the site. We attribute quite a bit of that dose reduction to our zinc injection project. I have some information on a later slide about that. Farley's dose exposure for calendar years is dramatically lower after we begin the zinc injection.

DR. SHACK: Are your steam generators

sized to allow you to operate power?

MR. FRIDRICHSEN: Mike is the best one to answer that. He was involved in the --

MR. MACFARLANE: Steam generator replacement, the size of the steam generators was actually picked to be a equivalent replacement to the original steam generators. The original steam generators were 50,000 square foot surface area design but that was an alloy 600 tube. When the replacement is in it's a 54,000 square foot to make up for the difference in heat transfer characteristics. That's not to say that the plant cannot support another up-rate but the generators themselves were not really selected on that basis.

MR. SIEBER: What's T-hot in that point at full power?

MR. SIEBER: About 609 approximately. Maybe 607.

MR. MACFARLANE: It's licensed to 613, 609 or 610 is what we actually run.

MR. FRIDRICHSEN: Our next slide is the indicator of our NRC performance indicators were all green and have been since the first order of 2001. All our indicators have been green.

Some of the features of Farley. The main

point on the first one is that it's pre-stressed/post-tension dry containment. We don't have the ice condenser design. We have a safety related cooling water pond. We have six off-site power sources through interconnections with Southern Electric System.

Five emergency diesel generators on site. Four of those are the safety diesel generators. One is the alternate AC power supply for station blackout. Forced-draft cooling towers and we operate on 18-month fuel cycles.

MR. SIEBER: What's the size of the off-site power diesel generator in horsepower?

MR. FRIDRICHSEN: Twenty-eight-fifty kilowatts.

MR. SIEBER: Okay.

MR. FRIDRICHSEN: And we have three 4075s and another 2850.

MR. SIEBER: And they're 4160 volts?

MR. FRIDRICHSEN: That's correct.

MR. LEITCH: So in a station blackout you don't assume -- I mean, the fifth diesel generator is not lost. Right?

MR. FRIDRICHSEN: That's the assumption.

MR. LEITCH: The assumption is that the fifth diesel generators will still work in a station blackout?

MR. FRIDRICHSEN: Yes. Mike is the technical lead on all this stuff.

MR. MACFARLANE: Yes, the fifth diesel dedicated to station blackout service. However, it can be started and if you had an event where one of your emergency diesels failed to operate, you could start this SBO diesel and realign it but it is a B-train setup and it serves strictly as the SBO diesel. It was originally part of the emergency diesel generator design and when the blackout rule came out it was separated off as part of our licensing basis for SBO.

MR. LEITCH: And that's the one that is referred to as 2C.

MR. MACFARLANE: Correct.

MR. LEITCH: I was a little confused by that as I looked through it. Now, do you have ignitors in your containment?

MR. MACFARLANE: No. We have electrical recombiners.

MR. SIEBER: Do you have cross-connects on the 4160s between the units?

MR. FRIDRICHSEN: The way our normal distribution system is is that there's an A and B start-up transformer per unit. There is a capability to supply power from one unit to -- from one start-up transformer. The Bravo start-up transformer could supply the A-train and the B-train if it has to. They are interlocked not to allow that but they can.

MR. SIEBER: If you have one unit that was black and the other one was on diesels, could you cross-feed to the black unit? That would have been a design change for you.

MR. FRIDRICHSEN: I'm not sure I can answer that not knowing the latest procedures.

MR. LUNCEFORD: Are you talking about doing it from the diesels crossing over one use diesels to another one?

MR. SIEBER: Yeah.

MR. LUNCEFORD: I don't believe that can be done other than this 2C diesel which can do either units B-train and it's got the interlocks to allow that to happen.

MR. SIEBER: Some plants can and some can't.

MR. LEITCH: So except for the electrical lash-up the five diesels are identical. Is that

correct?

MR. FRIDRICHSEN: No, sir. There are three large diesels and two small diesels. The large diesels are 4070 kilowatt and the smaller is 2850.

MR. LEITCH: 2C is one of the smaller ones.

MR. FRIDRICHSEN: That's correct.

MR. LEITCH: As is the 1C.

DR. BONACA: Your site is characterized by non-aggressive groundwater. Right?

MR. FRIDRICHSEN: That's correct.

DR. BONACA: Okay. And you do have -- I was speaking of the containment building and the history is good there, although you had one cracked tendon but that was a different issue, I guess.

MR. FRIDRICHSEN: I'll get to that on the next slide.

To give a little bit of our operating history, in 1983 we performed the up-flow mod on Unit 1. This was in response to a design issue with the Westinghouse reactor vessels and the original design was down-flow mod and that created a pressure stress on the baffle former joint and it would open and it caused baffle jetting on the fuel. We had some fuel failures in 1983 so we did that up-flow mod to

alleviate that problem.

In 1985 we had the cracked anchor head on containment tendon on Unit 2. It was on the field-installed end of the tendon and was due to hydrogen-induced stress cracking. Then in 1988 Farley was the subject of a Bulletin 88-08. We had a thermal cycling event that was occurring due to bypass valve leakage that caused a weld to crack on a safety injection to reactor coolant loop. It was sort of the source of a --

DR. BONACA: That was on a charge nozzle, right?

MR. FRIDRICHSEN: That's correct.

DR. BONACA: And that was due to thermal cycling?

MR. FRIDRICHSEN: That's right. Then --

DR. BONACA: How was it fixed? You must have done some modification.

MR. FRIDRICHSEN: Well, on Farley's design we pulled out the bypass line. There was no real need for it so we cut and capped it. That source of leakage was taken out.

MR. MACFARLANE: Just as an add we also installed some temporary monitoring thermocouples to demonstrate that we don't have cycling going on on a

lot of the other lines and also that line.

MR. FRIDRICHSEN: We still monitor that information.

Then in 1994, as I mentioned earlier, we started the zinc injection project on Unit 2. We started on Unit 1 in 1999. We feel strongly that the dose reduction benefit is obvious. The laboratory information shows that the reduction in initiation of stress erosion cracking and infirmary water stress erosion cracking is reduced by the zinc injection.

DR. BONACA: It has nothing to do with license renewal but could I ask why you are at 18-month cycles? Most people have moved toward 24-month cycle.

MR. MACFARLANE: The way I've had it explained to me, and I can't say I can really give you a total explanation, is that the economics from the fuel go to a two-year cycle on PWRs. I've actually gotten this from a Westinghouse person. It's just not there when you look at the total cycle and economics of it that you don't get to two years. That's not to say it might change. To my understanding right now that's kind of what the thinking process is, is that the economics don't bear it out.

MR. SIEBER: You're balancing an increased

fuel cost against the extra downtime. Let me ask you a question on this slide before you go on. Back in the '80s there was a problem on Westinghouse three-loopers with split pins that were breaking.

MR. FRIDRICHSEN: That's correct.

MR. SIEBER: Did you replace your split pins?

MR. FRIDRICHSEN: As a matter of fact, we have just finished our second replacement on Unit 1.

MR. SIEBER: Oh, really?

MR. FRIDRICHSEN: Yes.

MR. SIEBER: What did you find this time?

MR. FRIDRICHSEN: It's just been completed this week. We did a replacement in the early '80s and we subsequently have done another replacement on Unit 1.

MR. SIEBER: And that was based on your own inspection or some code requirement or what caused you to inspect them and find cracks?

MR. FRIDRICHSEN: I'm going to ask my associate, Wayne Lunceford, to address this.

MR. LUNCEFORD: Yes, this is Wayne Lunceford. The split pins on Unit 1, the original design were Alloy 750. They were replaced with a subsequent design, still Alloy 750 split pin. Even

though there were lower stresses, there had been industry experience now with that second generation design failing due to stress corroding and cracking notably at Wolf Creek.

The issue for them was economics and that the nut portion of the split pin was carried out and did a pretty good banging job on their tube sheet of their recently replaced steam generators so Farley decided to preemptively replace those X-750 pins with 316 co-work pins.

MR. SIEBER: Thank you.

MR. LUNCEFORD: Unit 2, by the way, already has replaced their split pins with 316 co-work stainless steel.

MR. SIEBER: Well, the original problem, as I understand it, was the sharp edges in the machine to make the pin in the first place. The steam generators where you had the loose part, those are the new steam generators?

MR. MACFARLANE: He was speaking of Wolf Creek. Farley has not had that experience.

MR. SIEBER: You don't have that problem.

MR. FRIDRICHSEN: Not with the new steam generators. We did in the early '80s have one split

pin break and get into the primary system on one of the steam generators.

MR. SIEBER: That makes them hard to inspect after you bang the tube shut.

MR. FRIDRICHSEN: Moving along with operating history, we operated each unit in 1998 by 123 megawatts thermal per unit. Then in 2000 and 2001, as I already discussed, we replaced steam generators on both units. We replaced it with the Model 54F Westinghouse design, Alloy 690 tubing with stainless steel support plates and full depth roll.

DR. BONACA: And they are thermally treated, right, that 690 TT?

MR. MACFARLANE: That's correct.

MR. FRIDRICHSEN: And as we move on, we are currently in the process of doing the first reactor vessel head replacement on Unit 1 and we'll do Unit 2 next fall, next October.

DR. BONACA: But where are you on the subceptability curve for the vessel head?

MR. LUNCEFORD: The original heads were in the high category. That was part of the rationale for preemptive replacement of the reactor vessel heads even though there has been no cracking detected to date at Farley.

MR. SIEBER: Are you a hot head or a cold head?

MR. LUNCEFORD: It is a hot head design, 597.

MR. SIEBER: Okay. Let me ask another question. You don't have to go back to the slide but slide 5 gave things like passing factors and outage duration for all the way to 1999. I noticed the capacity factor for Unit 2 in 1999 was pretty low. What happened that year? It didn't look like your outage was too long. You must have had some trips or something.

MR. FRIDRICHSEN: I'll have to defer. I was out of the country at that time.

MR. SIEBER: Well, I'm curious. You don't have to provide me with an answer if you don't have one readily available.

DR. BONACA: So now in your reactor vessel head inspections you didn't find any leaking CRDMs?

MR. FRIDRICHSEN: That's correct.

DR. BONACA: You inspected those so your bottom heads?

MR. FRIDRICHSEN: Yes, sir. One of my later slides we talk about it.

DR. BONACA: Okay.

MR. FRIDRICHSEN: We've done bottom head inspections on both units with no indications.

DR. BONACA: You replaced the thimble tubes in one of them. Right?

MR. FRIDRICHSEN: Yes, sir. I think we replaced them in both units now. We've done some on -- I know we did Unit 1 in the 1998 time frame.

DR. BONACA: I mean, I was trying to understand the criterion you have. I mean, you replaced them because you had a defect in them that you identified or thinning was beyond a certain criterion or just a precautionary step?

MR. FRIDRICHSEN: We had undertaken a program of eddy current testing since either a bulletin or information that came in the early '90s. We had been doing eddy current and had seen progressive wear and decided at that time to replace the thimbles with, I want to say, the chromium. It had a hard surface at the interface where it penetrates the vessel.

The purpose of this slide is to show that our management, our company, has made consideration for long-term operation at plant Farley. We've done a lot of things that we consider focused on the long-term. Of course, steam generator replacement and

reactor vessel head replacement were two big issues. We have just completed earlier this year a complete replacement of the cooling towers. The original construction had become kind of frail and we replaced them with new design, new construction.

We are also in the midst of getting our dry cask storage installation completed and get started with loading casks. I don't know the exact schedule for when we'll commence with that but that is in our long-term plan.

Additionally in the 1998/'99 time frame we conducted baffle former bolt replacement on both reactor vessels for concern of lose parts. There was an issue at the time. I think it was primary water stress erosion cracking of those bolts. We went ahead and we inspected all of them. The modeling showed and we had prepared to replace about 275 on Unit 1 and 200 on Unit 2. We did that in '98 and 99 respectively.

Now we'll move a little bit to the meat and potatoes of license renewal. This slide we say is consistent with past applicants. That is where we ended when we originally started. We had adopted the NEI methodology, (a)(2) methodology. (a)(2) was going to include electrical targets at a 20-foot radius from a water source.

After discussions with the staff and some work we did between ourselves we decided to revised the process to go with that consistent with prior applicants for the (a)(2) scoping. We say consistent with past applicants but there was an iteration in the development of that.

MR. LEITCH: It looked like it took a couple of iterations to get that resolved but you did eventually do away with the 20-foot criteria?

MR. FRIDRICHSEN: That's correct.

MR. LEITCH: And you also now consider in addition to electrical components both mechanical and structural components.

MR. FRIDRICHSEN: That's correct.

MR. LEITCH: The one part of that, I think that RAI had like five questions in it. 20-foot was one of them and mechanical versus electrical structural. There's another. The one part that surprised me a little bit, and maybe this is consistent with past applications, where there were gas-filled systems you considered the failure of those systems to be noncredible.

I guess I was surprised at that. I could see perhaps saying what happens if one of those systems fails and rationalizing that was not probable

or not troublesome but I didn't understand the rationale that said that the failure of the gas-filled system was not credible.

MR. MACFARLANE: The failure of the gas systems is actually addressed in the NRC ISG and what they ask you to do is to deal with your plant specific operating experience that you've had on those systems. The focus is on a failure type that can lead to the failure of such related equipment so it's not just the failure of the gas system itself but it's also leading to a failure of such related system.

If you did get a breach in a gas system, whether or not that has the potential to cause a failure in another system you have no water spray effect and you've got rapid expansion of the gas if it's a compressed gas. Most of the gas systems are not on extremely high pressure anyway. They are 100-pound pipe systems.

Then the issue that would be remaining is could the system fall and that has already been shown through industry-wide type operating experience looking at not just nuclear but other facilities that those systems do not -- we have the supports already in scope and age managed and then the gas systems do not fall essentially. You don't have a failure hazard

as long as you are managing the supports.

MR. LEITCH: Perhaps my question is really with the NRC staff because I agree that what you did seems to me to be in conformance with their position. I could visualize a 100-pound air system failing in such a way that the jet of air coming out the failure might damage some electrical equipment like a limit switch or pressure switch or something in the area. I guess the NRC was happy with the resolution of this ISG. I guess I'm just not happy with the resolution of this issue. Maybe you can talk to that when you get to that part of your presentation or now, whatever.

DR. KUO: Yes. Maybe when we get to that part of the presentation we will try to answer.

MR. LEITCH: Okay. Let me just make sure you understand what my question is. RAI 2.1-1 there were five issues that you raised. All five of those issues were satisfactorily resolved.

DR. KUO: Right.

MR. LEITCH: I agree that the resolution of four of those five. My question is that one of those says basically gas-filled system failure is not credible. Therefore, we're not going to consider that. That's the one I would like to hear a little

more discussion about.

DR. KUO: Okay.

MR. LEITCH: Thank you.

DR. BONACA: I had some questions about some components. They are not in scope and I would like to hear why they are not. I mean, CRDM cooling system is not in scope.

MR. MACFARLANE: The CRDM system itself is part of the normal rod control. In terms of the safety system when you talk about doing a rod insertion, that mechanism is not really want comes into play. You basically release the rod and gravity drops it down. It doesn't actually perform a safety function and that's why it was not put in scope. The cooling system is not relied on for any type of containment analysis or anything like that.

DR. BONACA: Okay. Now, the screen wash system we have seen this before but I always have that question. I mean, the screen washes them up?

MR. MACFARLANE: The screen wash was not in scope. That is handled through the operators. The intakes themselves, the traveling screens AR were put in the structural side of the house.

DR. BONACA: Those are the river water intake structure. That is not in scope, is it?

MR. MACFARLANE: No. The river water intake structure, the situation there is that's the structure at the river, the river water system that feeds the pond and then the pond becomes the ultimate heat sink so that structure, although is important to operation, is not important to safe shutdown.

DR. BONACA: Finally, the in-core instrumentation, I guess you can use it for NSFT related application?

MR. MACFARLANE: No, not in-core.

DR. BONACA: Not tied to any --

MR. MACFARLANE: In-core is for flux mapping and those issues. The ex-core is what's actually --

DR. BONACA: The tech specs. Any connection to that?

MR. MACFARLANE: Well, we are required to do flux maps and those types of things and that's just during normal operations. In terms of responding to an event for detection ex-core system is what actually does that. It's part of the reactor protection system.

MR. SIEBER: Your tech specs for flux map and your launch for 30 days and if you fail to do it you shut down so nothing is really required.

MR. LEITCH: I had another question about scope and the license renewal application, page 2.1-15. It says, "SNC has included in scope those switchyard components controlled by the plant that are necessary for recovery of off-site power." Should I be focusing on the words "controlled by the plant?"

In other words, I don't know who controls what. That's kind of a utility unique decision. Sometimes the breakers in the switchyard are controlled by others and sometimes they aren't controlled by the plant but I don't see what that has to do with whether or not that equipment should be included in the scope. It sounds like you're saying here that only those things that are controlled by the plant that are necessary for recovery of off-site power are included in the scope. I just don't understand.

I mean, we have some plants, for example, where there is an adjacent hydro plant that is controlled by a totally different organization. Those portions of the hydro plant that are necessary for recovery of off-site power are included in the scope even though they are beyond the control of the organization that is operating the nuclear power plant. I guess I was puzzled by the words "controlled

by the plant."

MR. MACFARLANE: The way that particular scoping was done is, you know, he talked earlier about we've got six different off-site feeds and they all go into the high-voltage switchyard. Then from that switchyard there's a point where it connects into our feeder system and goes down into our low-voltage switchyard. Then there is actually a site procedure when you want to restore off-site power if you have a loss of off-site power in the event of a blackout type situation.

That is what we put in scope is that primary means to feed to switchyard in responding to that event. It makes an interface in that switchyard but in that switchyard you define the high-voltage sign and then the feeder sign going to the low-voltage switchyard.

The actual switchyard itself is considered -- it has kind of a unique ownership in that it's partly run by the plant and partly run by Alabama Power. Controlled by the plant, I guess, I can see where that would be confusing but that really doesn't have any bearing in terms of where that distinction was picked. It's really picked based on the procedures for restoring off-site power.

MR. LEITCH: So the fact that some of those breakers may be under the control of Alabama Power doesn't exclude those from the scope.

MR. MACFARLANE: Right now all those breakers are under the control of -- the site has an operator that goes out into the switchyard.

MR. LUNCEFORD: But you're right, it doesn't exclude them from the scope.

MR. LEITCH: Okay. Thanks.

MR. FRIDRICHSEN: The next slide will talk a little bit about the GALL comparison. Wherever possible we use the GALL tool as much as possible. We did note that in our review that there were some material environment program combinations that were not in GALL but we had components and systems that needed to be in scope.

The aging management wasn't identified in GALL and the best example we can site is that we have in scope in some places some stainless steel piping in a varied environment and that series of combinations is not addressed in GALL so we were not able to use GALL in those applications.

Then also in some plant specific programs, for example, the flux thimble program and external surfaces monitoring programs were two programs that

were generated plant specific for our application.

DR. BONACA: One thing that I notice, and this is not the first application, is that on the fire protection issue there are frequency of inspection of C02, halon systems, and so on. Typically licensees are proposing whatever they are doing now, like in your case 18 months. GALL says it should be inspected every six months.

Typically NRC says, "Okay, it's acceptable the way it is." I have already raised this issue before. If it's acceptable to go to longer time, I think GALL should be relaxed to include that and maybe there is a plan to do so or vice versa. Then if it isn't acceptable in GALL, then you should go to a more frequent interval. The question I have is like on the issue of C02 and halon inspection. Why do you feel 18-month inspection is adequate?

MR. MACFARLANE: In the case of the halon and C02 what you really end up with is a center of gas that is maintained in a dry state. We really haven't had any trouble in terms of internal operating experience. I don't want to say it was called an exception. I can't remember if it was classified as an exception or a clarification but we did use an 18-month frequency and it was accepted by the staff.

It's consistent with what you're talking about with other applicants.

DR. BONACA: I understand it's a dry system. But the question I raise why does GALL still having a requirement for six months? I mean, I'm just raising the question. The guy who reviews it why is it always acceptable to relax because this is the first time. If so, then why not make it -- relax the requirement into GALL?

DR. KUO: This is really a good question and this is the whole purpose of updating the GALL right now.

DR. BONACA: So you do agree, in fact, that a longer interval between inspections is acceptable for this kind of --

DR. KUO: For this plant, for Farley case, we did agree with it and that we will provide you the basis for that during the audit presentation.

MR. MACFARLANE: Just to add to what was said there, I think you're correct. There are several programs that have those kind of little issues and I believe the staff is trying to look at addressing that in the GALL update. The industry is also updating its documentation and the schedule for that is sometime next year in terms of getting it all the way through

the process. There are several instances of that kind of thing where there's a lot of precedence on it that should be incorporated into the future goal.

MR. LEITCH: I had another scope question. The tank atmospheric events, there was apparently some omissions or inconsistency regarding whether they were or were not in scope. This was mentioned in the NRC inspection report.

I guess specifically the RWST, CST, RMU, some of the events were in scope and some were in scope. I guess it's all been straightened out now and they are all in scope, but my question really was was that just one of a kind or was there any process type of issue that was uncovered by that inconsistency?

MR. MACFARLANE: The tank vent issue really got into in resolving it we did go back and look at all of our atmospheric type tanks. What you have is a couple different situations that can occur on a tank vent and you can have some tank vent systems that actually are a pipe system and they might have some supports that might be inside the structure. When you start looking at aging of a tank vent, you are actually going to increase the vent area so it doesn't become an issue in terms of being able to impact the ability to do the event.

You try to maintain your vent as opposed to in a couple of these thanks the situation was you had a fairly significant length of piping on top of the tank that is the vent. The issue became if you did have some aging that thing could potentially, although somewhat of a remote possibility, crimp or collapse and close off or reduce your vent capability.

It was done inconsistently among a couple of preparers and that's what set that whole thing off so we went back and looked at all of those and put all of them in scope. We don't have any of those that really fall into the supported type piping vent system. Really most of them mount right on the tanks.

MR. LEITCH: So I guess what you're saying is it was one-of-a-kind situation that didn't reveal some underlying flaw in their scoping process.

MR. MACFARLANE: The thought process at the time was that the aging event would not be an issue from an (a)(2) standpoint and that the event surface would increase. They had not considered the crimping off aspect so that was really what was the change, I guess, in terms of an additional failure mode, so to speak.

MR. LEITCH: I guess my question goes more to communication between the groups that were doing

the work. Evidently there was one group --

COURT REPORTER: Mr. Leitch, I can't hear you.

MR. LEITCH: Evidently there was one group that did consider the crimping and another group that did not consider the crimping.

MR. MACFARLANE: It's really the difference in individual preparers and different thought processes on or between the two. Since that time we did get everybody together on that particular issue and reviewed it and that's where we made the decision as a project to consider that a credible mechanism. That's not part of our process in that we consider that mechanism.

We did look at some other plants and what they had done and they had different situations on the same tanks. They had piped supported systems so they have a different conclusion. Interestingly enough, you can look at an event on the same tank at different plants and you will actually get a different result and it has to do with the physical installation.

MR. LEITCH: My question, though, is not so much about the tanks as it is with communication of thought processes and experience between different groups that are doing similar work.

MR. MACFARLANE: It's actually not a different group. It's all in one group. It's just two different mechanical engineers doing the preparations and I can't really tell you who the checkers are. I don't have that information off the top of my head but it was just a difference of how they did it, it could happen type thing.

It was not really a communication standpoint. They actually sit right across from each other. They are looking at a lot of different things in that particular case. In some cases they just didn't view that as a real possibility. We actually had a long discussion about whether or not to challenge the position taken by the inspectors on this. We decided that from our standpoint it was conservative to put it in and we decided to do that. It was still subject to some debate in terms of is it really a valid mechanism.

MR. LEITCH: Okay. Thank you.

MR. FRIDRICHSEN: And moving on we'll talk about some of the key exceptions, differences we have with some of the GALL programs. These are our key, some of the things we consider more significant. We have a slide a little bit later that talks about some of the minor things.

The first example is the reactor vessel surveillance program. The GALL recommends that all capsules be removed at an exposure of 60 years fluence. At Farley those capsules will remain in until 80 years of exposure. That's one difference that we have with the GALL recommended program.

Another one is relative to the Reactor Vessel Internals Program and that's really a function of the evolution of this issue in the industry and that the activities going on in the industry now are somewhat at a different level than what the GALL recognized and, therefore, there's a higher tension being applied to it.

We're going to go beyond what's in the GALL for that program. We're going to sort of follow what's on with research in the industry. We'll follow what the EPRI-MRP is doing. Somewhere in the two years prior to the period of extended operation time frame we'll submit the program for staff review and approval.

Another exception is with the non-EQ cables and instrumentation circuits. We are going to base our program on the alternate program composed by the Electrical Working Group. This program is different from what's recommended in GALL.

The last example that I'll cite is that with the Water Chemistry Control Program for closed cycle cooling water the GALL recommends forms testing for pumps and heat exchanges and our program is going to credit every monitoring guidelines. Those are the four or four of the more significant differences we have with GALL. In our mind that's not -- these programs are not enormous exceptions to what's in GALL.

Then some of the minor things are relative to. We'll even use the term clarifications. There were different or later versions of codes and standards that we're applying that are referenced in the GALL or that we may expand our program beyond what's in GALL or that there is later NRC guidance for those programs and, therefore, we are citing that as our reference as opposed to GALL.

MR. LEITCH: I have a question about compliance with interim staff guidance. You go through the license renewal application a kind of detailed explanation of your compliance with the various ISGs. That all looked good and I thought it was pretty helpful but I was puzzled by the one about fuse holders.

You say, "Since fuse holders at Farley

have no aging effects requiring management, the attributes of ISG-05 do not apply." I guess my question is what's different about your fuse holders? Don't they corrode like other people's fuse holders? I just don't understand what's different there.

MR. NGUYEN: My name is Duc Nguyen from the electrical engineer branch. We are the one who issued ISG. The fuse holder has two parts, one the installation portion and one the metallic portion. The installation portion include the GALL XI.E1. We use inspection to inspect the installation material due to local line by heat or radiation, hot spots.

For the metallic portion E1 is not applicable because of the concern we have. We had a contract go to 30 on the fuse holder and we found that some of the metallic portion have a crack. The problem was when they do the maintenance they took out the fuse element and it was in and out so many times the fuse clip have fatigue. That a problem we found in one of the 30. Therefore, we issued ISG. We say that for your particular plant you have to address aging effect of fatigue, corrosion, and vibration.

Salt land that aging effect is not applicable and they provide a reason why. For the fatigue they say we don't remove the fuse element. We

have the upstream of that fuse. When you run through maintenance you go through breaker and we trip it off so fatigue is not applicable to us.

Some plants are applicable to them because they say every time we go to maintenance we have to remove the fuse. That why if you did that, then we require them to have again management program. If you don't do that, then that aging effect is not applicable.

For corrosion for particular filing they say they are the fuse holder is contained in a cabinet inside the drum so the moisture and it's not an applicable aging effect. In ISG we say that you have to evaluate your plan and tell us why aging effect is not applicable. That is plant specific. Farley provide information and they address why they don't have that aging effect and we agree with that.

MR. LEITCH: So if I can summarize that in the aging effect due to fatiguing doesn't apply because they don't routinely take the fuses out.

MR. NGUYEN: They took off the breaker upstream.

MR. LEITCH: And the aging effect due to corrosion --

MR. NGUYEN: Because you're inside a

cabinet and low to moisture. And another thing they say is the fuse clip also coat it with silver or something, the material that prevent corrosion. That makes sense. Some applicant they won't get that and then they have to provide us the Aging Management Program. In the new GALL update we are going to propose a new program, XI.E4. That program will tell you what to do and we are going to do that in the next GALL update.

MR. LEITCH: Thanks very much. That's a very good answer.

MR. FRIDRICHSEN: It's very rare for us to do safety isolation by pulling a fuse. That's very rare. From here I'll transition --

DR. BONACA: Before you go on I have just a couple of questions. First of all, for your in-service inspection you found a bulge in the containment lining. That's a no-never-mind?

MR. FRIDRICHSEN: It was evaluated and disposition is acceptable.

DR. BONACA: What is the size of this bulge?

MR. FRIDRICHSEN: Partha, could you answer that?

Partha actually did the inspection.

MR. GHOSAL: There were two or three found by doing our inspection. The lining is quarter-inch thick and bulging is in between the support points so you do a meet span and each considered. We evaluated the situation and we measured the thickness of the liner and there was no decrease in the depth of the liner or anything so that kind of eliminated that there is any deterioration behind the liner. It was determined that it was during the construction time the bulging happened. It was nothing related to the age-related degradation.

DR. BONACA: It doesn't affect in any way functionality.

MR. GHOSAL: Right. Yes. There is no crack. There is no indication or anything.

DR. BONACA: The other question I had was regarding again the mainstream support failure.

MR. GHOSAL: You mean the concrete support failure?

DR. BONACA: Yeah. I think it was the mainstream line. Was it?

MR. MACFARLANE: I'm not sure exactly which question --

DR. BONACA: In-service inspection. I have to get the document out.

MR. MACFARLANE: We did have -- I suspect what you're talking about is during Unit 2 steam generator replacement we discovered several mainstream support hangers had failed. There was an extensive root cause investigation of that. We actually hired in Altran and some high-powered consultants and we actually did some modeling.

We installed some transducers actually in the mainstream system trying to pinpoint what was going on. We also did a lot of mitigative work. There was some vibration damper in the isolators that were put into both containment and into the aux building. I take that back, not the aux building, into the turbine building.

What they found out is when we did the upgrade I guess it had a little bit of an effect but the main issue was where our three lines that come out of containment go into a common header and they go into two lines into the turbine building, that header was causing -- it was actually initiating this flow-induced vibration.

The resolution was really putting in this dampener and isolators and those kinds of things. It was practical to try to change out that header. That's a pretty tight area and a major size header.

That was a real extensive effort that went on in that time frame and that was our operating experience. It was really treated as an initiating event. It's not an ongoing type of event.

They did analysis to make sure it had not been over-stressed and then we did monitoring after we did all of these modifications to prove that the modifications that were done did bring the amplitudes down to where they were in allowable limits and everything was fine. That's what was done.

DR. BONACA: So you don't have anymore of the conditions that cause the high-cycle fatigue, the ameliorating.

MR. MACFARLANE: Right. The piping we keep monitoring. We do hanger inspections when we shut down for an outage to make sure that we don't have any. The conclusion was that those made a significant reduction.

DR. BONACA: And you are still inspecting anyway. You in-service inspection looks at those areas.

MR. MACFARLANE: Right. We also inspect out in the turbine building area which is outside the ISI scope. We do check entire mainstream lines.

DR. BONACA: On a separate issue on the

diesel oil fuel, you have a discrepancy from GALL where you do not test for particulate.

MR. MACFARLANE: That's correct.

DR. BONACA: And I didn't understand. I assume that particulate meant impurities in the diesel fuel. The answer was that it was acceptable because it does not significantly impact on pressure boundary integrity. The question I had was what about the long-term work functioning of the diesel? I mean, would the particulate, for example, if it was impurities mean that the diesels may not function for the long haul as well as it should?

MR. MACFARLANE: I think what happened is we really just have a different set of standards that we use. That does happen to be one of the differences. The standards that we are committed to is actually in the tech specs and so we took the exception from the standpoint that the tech specs govern what we had. In terms of the quality of the fuel oil in terms of aging, what you're really looking for is whether or not you're looking for water and those kinds of things and we do do that.

DR. BONACA: Maybe the problem is -- I mean, I'm trying to understand. I understand you are testing for water and I understand what water does.

Sediment, I understand that, and viscosity. Maybe I should ask the staff what is this particulate that they are testing for. Are they impurities of a different type?

DR. KUO: Let me find out.

DR. CHANG: My name is Ken Chang. I'm the auditing leader of the Farley review. When the auditing was on site we did review the fuel oil chemistry control program and we identified -- we noticed the differences of the two standards, ASTM D 270-75 and GALL prescribed ASTM D 4057. We looked into the basics documents and the applicant did a comparison study of the ASTM D 270 and the D 4057.

Based on the parameters important to the corrosion these are properly monitored by both standards and also no significant differences exist in the ability of the program to manage aging following ASTM D 270-75 versus D 4057. Also, the operating experience confirmed that AMP B.4.2 has been effective in managing the aging effect. They also are following the tech spec requirements as part of the CLB which takes precedence over the GALL. It is accepted by the auditing.

DR. BONACA: I understand but it doesn't answer my question. I was trying to learn something

that I haven't learned. Specifically it says they should test for impurities and for particulates and they don't so I'm left with the question what is a particulate here? Some kind of impurity.

Clearly it can't be water because they've tested for water. It cannot be sediment because they are testing for settlement and they tested for viscosity so it can't be any of those issues. It has to be something else and I'm not getting the answer to what particulate means in GALL.

DR. CHANG: I don't think I have provide you the answer to that particular part of the question but the auditing and the main purpose is to verify that these AMPs are adequate to managing the aging effects for that purpose. If you are interested in knowing the answer to the other part of your question, I can look into it and provide you the answer.

DR. BONACA: If you could. I mean, clearly GALL must specify --

DR. CHANG: GALL must be for a reason.

DR. BONACA: -- for a particulate. I would like to know what it means.

MR. LUNCEFORD: If I could provide a clarification maybe. We're talking about total particulate. I believe it's ASTM D 2276 and you look

in there for a particulate that has a similar specific gravity as the fuel that doesn't settle to the bottom.

The test there is a toluene test where you are actually vacuuming through a filter cloth so you look in what remains on the filter cloth. From our perspective that has more to do with the active function of the diesel, not something that would settle to the bottom of the tank like water or heavy sediment that would contribute to corrosion on the bottom of the tanks.

DR. BONACA: But this particulate could hurt the diesel.

MR. LUNCEFORD: Agreed, but we consider that to be part of the active function of the diesel. We were concerned with remaining the integrity of the fuel system components, especially the storage tanks where corrosion would tend to occur on the bottom.

DR. BONACA: Okay. If I have an expensive diesel engine car, I would make sure there are no particulates there either. I understand now. This provides an answer to my question.

MR. SIEBER: You might even get a fuel filter.

MR. LEITCH: While we're right on that point, I had another slightly different question about

fuel oil. It seems as though the fuel oil sampling program for the diesel-driven fire pump, not the emergency vehicle but the diesel-driven fire pump, is not the same as the sampling procedure or the testing procedure for the emergency diesels. Why is that? It wasn't clear to me whether we were going to make that testing procedure the same as for the emergency diesel fuel oil supply.

MR. MACFARLANE: You're correct in that the way we monitored the fuel oil tanks for the fire pumps was quite a bit less -- you know, it's not under tech spec type surveillance. That was a weakness we identified during our review so changes to the fuel oil monitoring program are being implemented as a result of renewal to remedy that situation.

The actual source of the fuel oil that's used in that tank, though, comes from the same source. The way we actually bring fuel oil on site is we take our old aux boiler fuel tank and we off-load the tanker truck into that tank and then sample there so we verify the quality of our fuel oil before it ever enters into the actual storage tanks for the diesels.

The same thing for the fire pump diesel. Some of the things we're doing in that program to address the fire pump diesel storage tank, one of the

items we added was a periodic draining and sampling of the bottom of the tank that didn't currently exist. During the AMP/AMR inspections from the region some questions were asked about that tank and we actually did some things.

We went out and did some UT on the bottom of the tank just to confirm that there hasn't been any adverse corrosion going on in that tank and that was done in response to an inspector's questions. We did recognize that was a weakness in the program. That's why in the application we stated that we would have to enhance that part of the program because it wasn't to the level we felt we needed.

MR. LEITCH: Okay. Thanks.

DR. BONACA: I had a question again on the issue of buried piping in tanks. There you are really -- first of all, you do have a lot of stainless steel and cooper alloy material resistant to corrosion. You are essentially having an opportunistic problem to inspect whenever you discover this piping which the standard has been used. I mean, everybody is using this so that's what GALL recommends.

Then the operating experience says that you experience three underground leaks over the past four years of in-scope and out-of-scope systems and

that you were successfully identifying the problem before system loss of function. I was kind of taken aback by three and four years seems to be a pretty significant number. Are you concerned about this frequency? Is it expected? Is it normal?

MR. MACFARLANE: What we see is the coding system on these carbon steel pipe has held up well and remained intact. What happens is you can get a stray rock or something in the back fill when this stuff was installed and it will nick that coating and we're seeing localized type attack that will manifest itself into a leak.

What we're trying to get across, I guess, with that operating experience was what happens is we'll see that leak and that leak becomes evident and we are able to detect those way before there is any significant potential for the loss of the line. They are very random and occur in different locations. There is really --

DR. BONACA: But if it was from original list, wouldn't it have manifested itself before? This plant has been around for 25 years.

MR. MACFARLANE: What you're saying is for an exposed surface of carbon steel how long will it take for that to actually corrode through from the

outside. Of course, then you also have corrosion issues on the inside as well going on with the service water itself. Our cast iron stuff has held up extremely well. We have no issues really with the cast iron but the carbon steel we do have cathodic protection system on it that we don't credit.

It is in use and does protect the piping in the majority of locations. There are a few locations that the cathodic protection system is not effective and that's why it's not credited in renewal space because there is some problem areas mainly around the structures because the structures act as a big sink for the current so we didn't feel we could use that as a viable renewal program. The failures we've seen have been mainly on nonsafety sections but we have had a little bit on some of the safety-related piping but nothing that would alarm us to my understanding.

DR. BONACA: Does the system have common experience at other sites? I would like to know.

MR. MACFARLANE: To my knowledge it is. It's pretty common.

DR. BONACA: I mean, I emphasize again that this is the approach that GALL recommends, too, for inspections but I guess we have to keep an eye on

it as we get into license renewal and plants get older we'll see if, in fact, what we're doing right now is still adequate.

MR. SIEBER: It's been a problem at some plants. I mean, a severe problem. It's not something that should be ignored.

MR. LEITCH: But I guess what I hear you describing it's not a couple of failures as a result of a general attack, but rather failures as a result of a specific damage site.

MR. MACFARLANE: That's correct. We have had a couple of things that are outside the power block area and on safety lines where you've got a crushing type of failure where a heavy load ran over top of it but we've never had that on the safety systems. Those are all protected.

We've had fire protection out in -- we have some old warehouses that are out far from the site from old construction days where something is run over and crushed that kind of thing and that's not aging at all. That's really related to the depth that was buried at the time it was installed.

MR. FRIDRICHSEN: From here I'll transition into commitment tracking to talk a little bit about our process for doing this. Naturally,

we've made commitments through both the renewal application process and the RAI and audit inspection processes. We track all those with an on-site commitment tracking system, a database, software that enters the commitment, assigns it a number, and then a responsible manager is assigned to follow up and implement that commitment by the required date.

The region, Region II, will be coming very early in March in 2005 to do an inspection on our commitment implementation process. After this process we'll get started loading those into the commitment tracking database so that will be ready for the region when they come down to see how we are getting all those implemented.

To this point we have made approximately 130 commitments by our tracking. What this is intended to illustrate is kind of the process. There are a lot of arrowheads on this thing but it's trying to show the variety of different things that are going on.

Through the applications and the letters we make our commitments and we have provided the staff an independent list that we call the future actions list. This is a subset of the commitments that reflect those activities that have to be completed

prior to the period of extended operation.

In addition to that, or as a greater set of those future actions, we have the overall commitments. Once we receive the safety evaluation -- let me back up. Let me say it differently. We will begin loading commitments based on what is in the draft safety evaluation. Our normal process would be after the safety evaluation before it's issued to enter the commitments.

For license renewal we're going to do that ahead of time. We'll load those commitments out of what's in the SER into the commitment tracking system and that will instigate the actions for the responsible managers on-site to make their procedure changes, program changes, budget changes, etc., to implement the commitment.

Independent of the commitment tracking system is our internal action tracking, action item tracking, and that is a program which at the discretion of the responsible manager he can implement an AI whereby he'll assign someone in his organization the responsibility to do the implementation.

That process is independent of the commitment tracking. If we are asked to status where we stand on our commitment tracking, it won't be on

the basis of what action item tracking has recorded. It's on what's out of the commitment tracking system process.

The future actions list, as I said, is really a subset of all the commitments and we've provided that to staff and they will follow up on that but there are other commitments and program revisions that may be necessary to complete a GALL program. Those are internal to the system already. We will be getting started getting those loaded and getting ready for Region II so they can come down prior to their inspection and have everything ready for them to see that we've got them all included.

MR. LEITCH: You have then a complete list of commitments?

MR. FRIDRICHSEN: That's true, yes.

MR. LEITCH: I guess I saw something that raised a question in my mind concerning whether something like this would be a commitment or not. There's a table, I think, where we're talking about TLAAs regarding fatigue. It's page 4.3-4, note 4. It's talking about fatigue on a certain piping section.

I forget exactly what it is but basically the answer is not to worry because that number of

cycles is based upon a load following plant and Farley doesn't follow load so it's a base-load plant basically so that cycling is not nearly approached. I'm wondering how do we know that, say, five years from now Farley does go into a cycling mode. Would there be something that would flag that and say, "Whoa, we've got to go back and relook at the number of cycles."

MR. MACFARLANE: The Fatigue Monitoring Program itself is set up to track all the significant fatigue cycles so if you were to change how you operated, you would have to go back in and look at the impact of the plant and then that would have to pick up that impact. The change process involved in doing something like that would pick that up so that's more in terms of process than terms of commitment.

The commitment itself is really the Fatigue Monitoring Program which addresses a set number of cycles. Also talks about our commitment to do a phone line monitoring. Those are commitments. Just as a little clarification to what was said, the commitment list is comprehensive of things we currently are doing but we've made a commitment into the application as well as things we will do in the future.

The future action list is really those things that still have to be done in the future. That is the difference between them. The commitment is the whole list. The future action list is really those things that are not yet complete which end up being like, you know, the Reactor Vessels Internals Program where we are going to submit to you two years prior to the period of operation. That's a future action.

So just to help clarify the distinction between the two nomenclatures, the staff a lot of times will call that same thing a commitment so there is a little bit of a terminology issue but just so you're aware that when we say commitment, it's has a little bit different meaning than when the staff says it. They are really talking about the future action list items.

MR. LEITCH: So there is no commitment then as such that says Farley will not load follow. But in the Fatigue Monitoring Program if there was a change in the operation, you would pick that up in your routine review of that program?

MR. MACFARLANE: Correct, because we've taken the hardware out to do the load following.

MR. LEITCH: Yeah, I know, but I'm just trying to understand if sometime in the future you

decided to load follow.

MR. MACFARLANE: Right. The change process itself. Just like anytime if we do an upright or any kind of change, you go through what are all your impacts and that would be part of that process.

MR. LEITCH: Okay. Not part of it but you're calling it commitment here.

MR. MACFARLANE: No, it's more looking at did it introduce any new fatigue cycles or fatigue usages and that would start feeding into the downstream calculations potentially impacted. You would have monitoring potentially impacted so the change process itself would have to look into all those things.

MR. LEITCH: Okay. thank you.

MR. SIEBER: Actually, load following doesn't introduce very many very deep transients that would cause fatigues, start-ups and shutdowns that do that, cool-downs. That's where the big cycles comes from.

DR. BONACA: Right.

DR. SHACK: You can have lots of little ones or a few big ones.

MR. FRIDRICHSEN: Industry issues. This slide is just to discuss some of the -- we've already

discussed the bottom-mounted instrumentation inspection results. We've done those visuals.

DR. BONACA: How easy to inspect those bottom head of the reactors?

MR. FRIDRICHSEN: Well, it's --

DR. BONACA: Is it accessible?

MR. FRIDRICHSEN: It's accessible. There's insulation that needs to be moved and scaffolding to be constructed but it can be done. Just recently I received a photo package that showed all the inspections they had just completed on Unit 1 this fall.

DR. BONACA: Unit 1 has new thimbles?

MR. FRIDRICHSEN: Yes, but the thimble is actually a tube within a tube. You have the conduit piping that the thimble passes within and then the detector passes within the thimble.

DR. BONACA: That's what was replaced.

MR. FRIDRICHSEN: The thimbles were replaced.

DR. BONACA: Okay.

MR. FRIDRICHSEN: The piping is still original. The VC Summer inspections in accordance with the MRP guidance, we've done those inspections also and we've seen no degradation in those

instances..

DR. BONACA: VC Summer inspections, I mean, those are inspections that were mandated because of the cracks identified in the nozzle of VC Summer?

MR. FRIDRICHSEN: Yes, sir.

DR. BONACA: Did you have to -- I thought that because of the insides of VC Summer your in-service inspection when you do volumetric would be somewhat affected by that issue. Have you changed your inspection process or procedure?

MR. LUNCEFORD: For those belt welds there was an MRP letter issued in 2003 which recommended that the bare metal visual examination be performed on all these welds. Farley has done most of those visual examinations with no indication of any cracking. No boric acid residue. None of those indications. When you are referring to the volumetric examinations, you are speaking of, I believe, Appendix 8, the performance demonstrated volumetrics. Is that correct?

DR. BONACA: No, I was referring to the fact that when they found the crack and leaking they went back to older nozzles and they perform at the current to identify superficial cracks and then when they found those they went in and they did volumetric.

Then they identified where were these cracks. I was wondering if that was part of these inspections.

MR. LUNCEFORD: To my knowledge, Farley has not done anything like that. There's the review of the data which didn't show any weld repair issues like VC Summer had on the weld. All of the examinations to date have not shown any issues and the visuals obviously came back good as well. Beginning with the next Unit 1 outage, Farley will be required to do performance demonstrated volumetric exams according to the new AME criteria.

DR. SHACK: When you do the performance demonstration for these welds, what's your performance demonstration going to be on? It's not going to be on the PWSCC crack presumably. You don't have any.

MR. LUNCEFORD: I'm not sure I'm going to be able to answer that question. They are still working on insuring that they get qualified examinations. We're working with Westinghouse and with Framatome to some extent to ensure that we are going to meet all of those criteria. That is still in process at this time.

DR. SHACK: The other thing, on that MRP exam there was some language that said you had to do a bear metal visual within two cycles. Are you then

committed to do a bear metal visuals some time in the future on some periodic basis?

MR. LUNCEFORD: As far as I understand, there is not a periodic requirement for that bare metal visual, although as we've just discussed, we'll begin doing qualified volumetrics at that time.

DR. SHACK: Also, you do a leak detection according to Section 11 requirements. Again, what is the frequency of that leak inspection?

MR. LUNCEFORD: If you are referring to the VT-2 exam that is performed, that's a normal pressure test that is performed at the end of every refueling outage so once every 18 months.

MR. MACFARLANE: Just as an add, what they do now is when we shut down we have what we call the sandbox covers that go over the reactor vessel nozzle areas which is the area where VC Summer had their crack. When we pulled those off we go in and we do a visual inspection of that area looking for any change, particularly indications of boric acid leakage and that's done every outage.

DR. SHACK: What is your insulation in that area, mirror?

MR. MACFARLANE: All our RCS piping and vessel and stuff is reflective metal insulation, RMI.

MR. LUNCEFORD: And I'd also add while we're on the topic, we had performed the bare metal visual examinations on all the pressurizer 82, 182 welds as well for both units 1 and 2 now with no unacceptable results.

MR. FRIDRICHSEN: Well, that --

DR. BONACA: I have one last question.

MR. FRIDRICHSEN: Okay.

DR. BONACA: There is a hot issue on the table and I'm sure there is a sump recirculation issue. Any insights on that?

MR. FRIDRICHSEN: We're prepared for that.

MR. MACFARLANE: I'd say we are prepared for that. In terms of the containment sump for Farley, just to give you a little brief background into our sump design, the Farley containment sumps are located on the bottom floor and it is essentially a screen box structure over top an intake pipe. It's not a recess sump like some plants will have.

They stood outside the bio wall and, therefore, the main loop piping and vessel are remote from where these sumps are located. The Farley containment design ever since original construction essentially have minimized any type of fibrous insulation.

The initial thought was that we had none but we have done a little research and found a couple locations. Primarily on all the reactor vessel and primary piping is reflective metal insulation, same thing with main steam and feed water.

MR. SIEBER: Steam generators?

MR. MACFARLANE: Steam generators. When we did steam generator replacement we actually looked at possibly using the thermal lag type insulation like -- I forget the brand names, Newcon and those types of insulation that are fibrous with a metal jacket.

We actually decided in that process that we had gotten a lot of benefit at minimizing any fibrous insulation in our containment so we made a conscious decision to go back with reflective metal insulation, even though we thought we got a little better performance out of the other types of insulation from a thermal insulation factor.

Right now we are doing this head replacement. When we did containment inspections as the result of some of the bulletins that came out on this sump issue, they found that around some of the penetrations where like the CRDMs penetrate the insulation package, there was this insulation material called Tempmat which is a fibrous -- it's like a cloth

but it's fibrous.

In going back with the new insulation package on the new head it will not have that so we're aggressively trying to eliminate those type of things where we can. The only other location, there's a little bit on the bottom head. However, that is limited by the reactor cavity which really does not come in contact with the containment sump. That is actually at an even lower elevation and it's enclosed to not flood during a recir event.

The only other place we have it is on sensing lines on the steam generators and they are located up above all the main loops. They are actually not in -- the only impingement zone they're in is their own. If that sensing line itself were to fail that you might get some damage there.

Overall we think we have pretty robust design features in terms of minimizing some of these aspects in terms of insulation. We've done coatings inspections. Overall our coatings are in excellent shape. We've actually had some comments from inspectors when they walked in there.

We have aggressively been looking at that and some of the way you are going to quantify this stuff is still up in the air in terms of how to

evaluate your sump so we are still waiting on resolution. There is a proposed NEI process and I know ACRS looked at that here recently and had some comments on it.

What we're doing is what we can today. We suspect if the conservatisms that are currently in the methodologies continue to exist that we will probably have to change out our sump screens but we have not reached that conclusion yet but we do believe that is probably where we will end up.

DR. BONACA: Okay.

DR. RANSOM: I have one question on the flow-accelerated corrosion program. I know it was discussed there and they mentioned extending the auxiliary feedwater turbine exhaust line or extending the program to that but there was no detail on how these inspections are performed or how often they're performed or how thoroughly they're performed.

What I'm thinking is that flow-accelerated corrosion is often times a very localized effect having to do with the scrubbing and the piping or steam droplet impingement or cavitation response. The question would be how do you find that sort of thing?

MR. MACFARLANE: We use a combination of methods. We do all our FAC program in-house. It's

all done at Southern Nuclear.

DR. RANSOM: How often is that done?

MR. MACFARLANE: We do inspections every outage and, of course, what we look at is -- the process they go through to determine what we look at is we use Checkworks which is the industry program for modeling FAC. We also use -- that's about 40 or 50 percent of the effort but then other parts we've got is really operating experienced based and industry based where they go in and you have to refine what you're going to go look at.

The model is not perfect. We look at those kinds of things every time an issue comes up. There was an issue on I think backside FAC on some welds and we did inspections related to that. The Japanese event that just happened recently we went in and looked at our programs to see if we had any equivalent areas and whether or not we had inspected it. Essentially we don't have a similar system to theirs in that they have de-aerated feed tank that is part of that issue.

However, we did find what was our closest equivalent to that which we had inspected in the past and we went ahead and did enhanced inspections subsequent to the Japanese event just to double check

it. We are proactively staying in this. They participate in the industry, the EPRI FAC Working Group and those types of things.

DR. SHACK: It says you are replacing piping with the chrome-moly stuff. What fraction of the piping is now chrome-moly?

MR. MACFARLANE: Essentially, the areas that have had to have FAC replacement so far have been limited to the turbine building. We just recently had some go into the aux building. That was a recent occurrence. Essentially your worse locations tend to be out in your MSR areas and then your cross-under piping under your turbine and the condenser and those kinds of things.

Then it progressively starts to move out. We do inspections throughout just to make sure we properly predicting what is going on. That is kind of what has been going on. We don't always replace chrome-moly. It's going to depend on what it is and then how expensive it is and those kinds of things and what kind of wear rates we're seeing. I can't answer your question on how much is chrome-moly. I don't have that familiarity with it.

DR. SHACK: Just while -- you replaced some nozzles with Alloy 508 and, again, in the SER it

says when you replace with the resistant materials you keep the piping in the program, although presumably you take credit for the lower wear rates. When you replace the nozzles with 508 will they stay in the program?

MR. MACFARLANE: To what nozzles are you referring?

DR. SHACK: Steam nozzles.

MR. MACFARLANE: Oh, in the steam generator itself? In terms of the replacement steam generator the main steam out of the generator has an extremely low moisture content so the main steamlines themselves are not actually FAC-susceptible due to the actual environment. That is talked about in the LRA and was evaluated by the staff.

It's really when you get into the drains and downstream is where you start seeing the FAC. So, to answer your question, that is really is not considered an aging effect for that. The moisture carryover when we did the testing post-SGR replacement was in the -- let me see if I get this right -- .04 percent or something like that. It's extremely low, the actual moisture carryover.

MR. SIEBER: I think Vic's question related to what resolution do you get out of one of

these inspections. The way I've seen them done in a lot of plants for the inspection people to establish a grid over an area the Checkworks tells them to look at in the spacing of the lines on that grid determine what the resolution is. Maybe you can tell me what your spacing is. Is it 1 inch by 1 inch or that kind of range?

MR. MACFARLANE: I don't actually know what the spacing is to be honest with you. I've seen them actually drawn on the pipes out there. They seem like reasonable grids. The actual selection of what gets inspected is actually not dictated by Checkworks. It's dictated by the FAC engineer who determines where they are going to go inspect.

He's got Checkworks and he's also looking at other industry inputs in terms of things that have been seen. The grids themselves, you know, they're covering -- you know, they do say they are looking at a weld location or a component location. They do quite a bit upstream and downstream to make sure they get a good look at what's going on in the vicinity because FAC is generated by a flow disturbance in a lot of ways.

MR. SIEBER: It's turbulence a lot of times that causes an eating out and that disturbance

in the wall reduction usually varies depending on the flow or the fluid conditions. If you have a plant that starts up and shuts down or cycles load or something like that, that can be a wider area than the plant that's running 100 percent power all the time because then the flow disturbance issues are fixed in one place.

Basically that's how this is done in one inch. Even though we won't hold you exactly to that number, this is typically what everybody uses so you have a series of data points that you can map out and determine where the wall thickness is reduced and where you have to do something.

DR. BONACA: Right.

MR. LEITCH: I had another question about a fact while we are right in that area. You mentioned in the commitments that the aux feed water turbine exhaust piping will be included in the flow-accelerated corrosion program prior to the period of extended operation.

Does that mean that is not going to be looked at until right prior to the period of extended operation? That sounds a little lax. I don't know if that's an area that is not particularly subject to flow-accelerated corrosion. Why wouldn't you be

looking at it sooner I guess is my question.

MR. MACFARLANE: The reality of what we're doing actually is going into the program. As we speak I'm not sure that the program document has been totally revised yet but it has been communicated to the FAC engineer and he is in the current revision of this FAC program, which I can't remember has come out yet or not, is going to include that item.

In terms of susceptibility it is a low susceptibility area. It's just one that we felt we would be better off putting in is really the determination we made. Of course, we're not the FAC experts, per se, but he agreed with this in terms of adding it into the scope. That would be a reasonable and conservative approach.

It will be in the program. In general our philosophy for most of these programs is that they will be implemented well in advance of the period of operation. It's just the language that was used in terms of making the commitment.

MR. LEITCH: Okay. I understand. Thank you.

DR. BONACA: Why don't we take a -- this, I think, will close the presentation.

MR. FRIDRICHSEN: Just some closing

remarks. We think that the staff's process was very thorough, very rigorous. We think they gave us quite a good scrubbing. We think that the new process, the new consistent GALL process added a lot of depth and clarity, a lot of better understanding of our programs by the staff. That had value, I think, to both staff and us. Other than that we are grateful for the subcommittee's time and your attention and willing to listen to us. That's all I have.

DR. BONACA: Thank you. With that we'll take a break for 15 minutes. Do you have a question?

DR. SHACK: No, just cheering.

DR. BONACA: Okay. Get back at 3:35.

(Whereupon, at 3:19 p.m. off the record until 3:36 p.m.)

DR. BONACA: Okay. Let's resume the meeting. Before we start the presentation, just a brief announcement. The red line on the Metro Rail is shut down for tonight because there has been an accident. Apparently there has been a crash on the Red Line. Just to let you know in case you use it. I use it.

MR. SIEBER: We could just keep on going.

DR. BONACA: It's not easy but we'll find some way.

DR. SHACK: Hitchhike.

DR. BONACA: Hitchhike, yes. We'll try not to delay too much the meeting. We have now the presentation of the NRC so we'll proceed with that.

MS. LIU: Thank you for that information, Dr. Bonaca. Dr. Bonaca and distinguished members of the subcommittee, good afternoon. My name is Tilda Liu and I'm the

DR. SHACK: What about the rest of us, but that's okay.

MS. LIU: All of you are distinguished. I am the project manager for the Farley License Renewal Application with the Office of Nuclear Reactor Regulation. This afternoon's agenda is as follows. I'll go over overview and highlights and we'll go over the review process, SER Section 2 on scoping and screening. And Caudle Julian will be talking about license renewal inspections. We'll talk about SER Section 3, AMPs and AMRs. Finally, Section 4 on TLAAs. We'll sum it up with a conclusion.

This slide provides an overview of the Farley application. Farley is the very first renewal application that used the newly revised NEI format. That includes Table 1, Table 2, and standard notes for the tables.

This is also the first pilot renewal to fully implement the consistency with GALL audits for AMPs as well as AMRs otherwise known as the new review process. Before I go further into the presentation, I would like to point out the staff's conclusion which is Farley has met the requirements of 10 C.F.R. 54 in terms of scoping and screening AMPs, AMRs, and TLAAs.

Highlights of the review. The draft SER was issued on October 15, 2004. There was no open or confirmatory item associated with the review. The staff noted that efficiencies were gained from the new review process. This is evidenced by a reduction in the number of REIs as well as on-site audits provided very effective interaction between the applicant and the staff which resulted in minimum number of formal correspondence.

I would like to provide your perspective on REI related statistics. There were a total of 163 REIs issued by 17 letters. Particularly, there were 64 on scoping and screening, 15 on AMPs, 70 on AMRs, and 16 on TLAAs. I would like to point out that the 70 questions from AMRs only three of which were from the audit team.

I would like to give you another perspective on the number of REIs from the other

applications. There were 280 for Summer, Robinson there were 360, and Ginna there were 224. These are all very similar Westinghouse designs to the Farley plant.

I also would like to point out the efforts involved for the staff in this new process. We held two meetings to discuss REIs and 56 telephone conferences to discuss these REIs. Because these REIs came in batches from the staff and we discussed them as we went along, we might have had two big phone calls or two big meetings. In addition to the REI responses provided by the applicant, the applicant also provided supplemental information to the application as well.

Continue on the highlights of the review. We had three license conditions. The first is very standard that you see in all the other applications. It's the FSAR update to be followed for the issuance of renewal license and that the commitments will be completed in accordance with the schedule.

The third license condition, I understand was added to Dresden/Quad as well, relates to the Reactor Vessel Surveillance Program. This third license condition requires that all capsules in the reactor vessel that are removed and tested must meet

the test procedures and requirements of ASTM standards to the extent practicable and that any changes associated with the capsule withdrawal schedule and capsule storage requirements must be reviewed and approved by the NRC staff.

More on highlights of the review. Additional components from eight systems, auxiliary systems, were brought into scope as a result of the applicant's revised methodology to 10 CRF 54.4(a)(2) as the applicant mentioned earlier. Of the eight systems three resulted Table 2 in Section 3 revised for AMR line items.

There was one Aging Management Program that was added after the application submittal. That was a plant specific AMP. It is Periodic Surveillance and Preventive Maintenance Activities Program.

MR. LEITCH: Regarding systems that were added to the scope -- brought into scope, I guess fire protection is an (a)(3) system.

MS. LIU: Correct.

MR. LEITCH: Were there any major additions to the fire protection program? I guess it just seems to me that a number of applicants in the past have had problems and it's been kind of a contentious area about whether certain things are

included or not included with respect to fire protection. Do you have that here?

MS. LIU: Fire protection was not one of the systems that was brought in scope.

MR. LEITCH: Okay. So I guess you feel quite confident about the scoping of the fire protection program.

MS. LIU: Yes. We went through a lot of details with the applicant and a lot of effort between the applicant and staff resolved the differences.

Moving onto the review process, this slide provides a listing of the activities associated with the staff's review process which includes scoping and screening methodology audit. As you know, there's consistency with GALL audits, table-top which is the in-house safety review, and regional inspections which Caudle will be talking about earlier. This next slide shows dates associated with the various inspections in August that I have just mentioned in the previous slide.

If I may provide you a conclusion statement first before I go further into discussion on Section 2 associated with the staff's review on scoping and screening. The staff concluded that the applicant's scoping methodology meets the requirements

of Part 54 and that the applicant's scoping and screening results included all SSCs within the scope of the license renewal.

Section 2 on scoping and screening methodology. Staff review and on-site audit determined that the applicant's scoping and screening methodology meets the rule. As I mentioned already, staff identified SSCs that meet the Part 54 for (a)(2) criterion and additional components regarding the scope for eight systems from the auxiliary systems.

There was an RAI, as Dr. Leitch pointed out earlier, to do with (a)(2) and I'll be discussing that in the next slide. The initial methodology that was presented by the applicant was as follows. It uses the spaces approach and eliminate the 20-feet criterion and extended valid targets to include mechanical and structural -- I'm sorry, valid targets include mechanical and structural SSC. That was the revised scope. The original scope, like I said, was only a 20-feet radius and limited only to electrical targets. Upon this revision included all targets, electrical, mechanical, as well as structural. That's all I have for that.

DR. WALLIS: They replaced this 20 feet with some spacing?

MS. LIU: Spaces approach. Correct.

DR. WALLIS: What was the physical basis of that?

MS. LIU: I'd like to defer that to Greg Galletti. He will be giving more details about that one.

MR. GALLETTI: My name is Greg Galletti. I'm with the Plant Support Branch. We did the scoping and screening audit. With respect to the 20-foot criteria, once the applicant had decided to abandon that criteria in support of going to a spaces approach, the space as defined here would be a continuous room that you have solid walls that would isolate that room from another location. Or you could have, for instance, a long hallway. That entire hallway would be considered a contiguous space.

DR. KUO: And, Greg, at this time could you also say something about the question before on the REI 2.1-1?

MR. GALLETTI: Sure. This is with respect to Dr. Leitch's question regarding the air gas systems. Just as a brief history, as you know, this issue goes way back to the early hatch days where we were discussing the fluid-filled piping and the likelihood of a pipe falling or calling an interaction

with a safety-related component.

As part of the resolution to those issues, we had put together the ISG. The ISG actually came as two independent letters. The first letter really addressed the fluid-filled portions of the system. The second letter then went on to address nonfluid-filled systems, air gas systems in particular.

In the second letter what we requested and required the applicants to do is to perform an evaluation, if you will, based on industry operating experience as well site specific operating experience to determine whether there could be the potential for air gas system interaction with those safety-related SSEs. In particular, what we were looking for is for them to discern "hypothetical failures" from true failures. Again, to be consistent with the rule and also to try to limit broadening the scope beyond what was reasonable for the regulation.

With that, what we found in this particular case is the application didn't have explicit information in there with regard to the evaluation of the air gas systems. Section 2.132, I believe, is the (a)(2) evaluation. It goes through the various criteria but it was, again, not explicit with their gas.

During the audit we went into that level of discussion to understand what implementing guidance they had to review this sort of thing and through interaction with their staff we came to understand that, in fact, they did perform both a site specific evaluation looking at corrective action, incident reports, things of that nature, things that happened at their particular plant which may lead to understanding for the potential of air gas interactions.

As a result of that conversation, we felt it was appropriate to ask the RAI simply because we wanted to get that better documented and be able to respond to that in the safety evaluation. That's really the genesis of why that question came up in this particular case.

MR. LEITCH: I guess I was just puzzled by the approach which seems to be to say based on operating experience this is a noncredible scenario. That is, it's noncredible that the line would fail.

MR. GALLETTI: Well, again --

MR. LEITCH: Well, I mean, I can understand an approach that perhaps said given a failure we don't expect to see any damage to a safety related system but it sounds like from the RAI and the

response to the RAI that basically what the argument is is that a failure is not credible. Not that damage from the failure is not credible but the failure is not credible.

MR. GALLETTI: Well, quite frankly, it would be both but, in this case over the course of years of review and discussion with NEI, we have not identified either industry or, in this case, site specific operating experience that shows that you would have those sorts of failures of these air gas systems which would, in fact, compromise your safety-related components. I think that is a fair factual statement as far as what we have been able to determine through review of operating experience as a whole.

MR. LEITCH: Well, I can think of cases where -- maybe this isn't -- maybe this doesn't fit the classification. I'm thinking of systems where an instrument airline in containment has failed causing the misoperation of an MSIV, for example. I guess it's not really -- the instrument airline is not safety related but the MSIV is. It's not an impingement kind of a problem. It's the failure that causes the --

MR. GALLETTI: Well, I think in most cases

where you have a true safety-related component that relies on a non-safety-related subsystem, if you will, to perform its function. In most cases those subsystems are designated as safety related for those particular plants so you are not going to have this (a)(2) interaction. In fact, you'll probably see those things brought in the scope for (a)(1) purposes.

MR. LEITCH: Yeah, I think that's right. I think the cases I was thinking of, as you correctly point out, would probably be (a)(1) situations. Yeah, okay. That's good. Thank you.

MR. GALLETTI: Sure.

MS. LIU: Okay. We're on slide No. 14. Section 2.2, plant-level scoping results. The staff identified SSEs that met the (a)(2) criteria and additional components requiring the scope for eight aux systems as I mentioned earlier.

For the scoping screening results related to mechanical systems, we looked at reactor vessel, reactor systems, ESF systems, aux systems, and steam power conversion systems. In addition to these, part of the staff review included a plant scope inspection conducted by the region. The inspection was conducted in May of this year.

Slide No. 15 continues on with the scoping

results. We looked at for the containment systems which includes PWR concrete containment, aux building, diesel generator building, turbine building, and other structures and supports. Finally, for electrical and INC systems there were 10 electrical and I&C commodity groups subject to AMR and the staff concluded that all were included.

The summary of scoping and screening, the staff has concluded that the applicant included all the SSEs within the scope of license renewal and that the applicant's scoping methodology meets the requirements of Part 54.

At this time I will turn over the presentation to Mr. Caudle Julian to brief you on the results of the license renewal inspections. Caudle was a team leader in these inspection efforts.

MR. JULIAN: Thank you, Tilda. My name is Caudle Julian from NRC Region II out of Atlanta. Myself and my inspection team have been doing all the inspections for Region II. We try to keep the same team together and have hopefully consistent results that way.

You've seen these slides before so we'll not spend time on 17. It's pretty self evident. We've talked about how the program goes before. Slide

18 talks about the scoping and screening inspection and I'm sure you are well aware of the purposes of that inspection.

The scoping and screening results at Farley were very, very good. We had nearly no issues to talk about there at all. I think maybe the issue you mentioned about the inconsistency and the tank vents being in scope was one that came up and all we know for sure it's an inconsistency in the drawing. Some drawing showed it in scope and some didn't and they corrected that issue now.

The next inspection, which is two weeks long, the Aging Management Program inspection. Again, slide 19 speaks for itself and we have seen it before. At Farley, again, we had very few issues to talk about. We were doing this one in conjunction with this time a pilot inspection of the service water system.

That's another issue that the regions have been tasked with pursuing now and we are doing three of those in Region II and Farley was selected as one. The same people who would be on my team doing the license renewal inspection went a week or two before and looked hard at the service water system and its monitoring and performance and found it in good

condition.

During the Aging Management Programs we looked at existing programs that have been there for years and we thought that in general they are all functioning very well. The only problems we ran into there were some what I'm going to call anomalies in results of fire protection surveillances where there were some fire protection routine surveillances that over time had shifted in our methods of performance and so the criteria that was traditionally there from the day the plant was started up was not being fully met.

The licensee is looking into that matter and we are going to pursue that, Region II is, in the future inspection. We have our routine fire protection inspection coming up in the spring. But that was not an aging issue. That's just a routine day-by-day issue. As we discussed before, those we turn over to routine follow-up by the region.

MR. LEITCH: Caudle, I have a question about your methodology a little bit. In the inspection report, attachment 2, pages 17 and 18 list a list of systems that are in scope it says yes, or not in scope it says no. Some of your methodology looks at those not in-scope systems and confirm with

the applicant that they, indeed, did not have components that should be in scope.

Now, what I was wondering is how did that list -- let me ask the question this way. Were there other not-in-scope systems that were not on that list? In other words, that was the licensee's list of in scope and not in scope. Did you look at any other not-in-scope systems other than the ones that the licensee said were not in scope?

MR. JULIAN: No, we have not been doing that. On the scoping and screening inspections we typically have started with the licensee's conclusion that you've seen in his license renewal application and there is always some inclusion of marginal ones, I guess, that they consider to be in scope and concluded no and our purpose is to go down and talk with them and look at the system in more detail than you could from the application and agree with their conclusion.

MR. LEITCH: So you agree with their conclusions that those systems ought not be in scope but you didn't really test -- if I'm understanding you correctly, you didn't really test whether there might be other systems that were not in scope that should have been in scope.

MR. JULIAN: We have not been doing that in the past. There's probably a wide variety of things in the plant that you could do that with but most things become self-evident most of the systems that you look at. I mean, if you move over to the warehouses and so on, it's obviously not close.

Most of them are not close really. One I mentioned earlier that I think we challenged in other places is control rod drive cooling systems. That was mentioned, I think, earlier in the meeting and we have concluded that they are right. That system is not needed to make the reactor trip.

MR. LEITCH: Okay. I just wanted to understand the methodology.

MR. JULIAN: Yeah, that's it. Again, returning to Aging Management Program inspection with respect to new programs, the applicant had there for our review some proposed implementation plans and proposed procedures that they intend to use in the future and that gave us a food feel for what their future plans are like. Some people are that advanced and some people are not at this stage but we thought that Farley did a good job in that area.

We did lots of equipment walk-downs, visual observation of the equipment in the plant. We

concluded that the material condition is being maintained adequately at Farley. We had very few things we ran into that caused us any problem at all.

In the fire pump house we saw a few, one, two, three, rusty components, mainly pipe supports than actually structural beams and they come from water being continually flooded on the floor. That condition had already been identified by the applicant and they had already written a condition report on it and that's good if they are out ahead of us identifying things and write them up. We like that.

We had a question about some service water piping where it comes out of the service water intake structure that's in a concrete vault that has obviously been flooded in the past. Some of my inspectors raised the question about, "Gee, that big pipe looks rather rusty on the outside and it's been flooded and exposed to air again off and on over the years. Don't you worry about the pipe corroding through from the outside?"

I understand that the applicant wrote a CR on that and there's numerous other little conditions like pipe supports and things in that area that could be flooded that they've written up and intend to repair in due course.

So our conclusion about the Farley plant as we saw it is that we saw nothing major in terms of material condition that presented any kind of a serious aging concern to us. We think Farley is in good shape and they are working hard to keep it that way.

In fact, one of the inspectors on my team again turned out to be a previously assigned resident inspector at Farley several years ago, six or eight years ago, and his conclusion personally was that the plant looks better today than it did when he was there several years ago and that's always good for us to hear. That concludes what I have to say with respect to inspections.

On the next slides we'll put up the performance indicators. That's already been mentioned, I think, by the Farley folks, Unit 1. The next slide is Unit 2. They are very much identical. Farley is all green with respect to the reactor oversight process. We've had no significant findings in the last few years that would even approach moving into the white or other area more significant so Farley is a good performer as far as we are concerned.

MR. SIEBER: I take it, though, even if the performance was not as good as this, it would not

factor into license renewal under the rule.

MR. JULIAN: Yes, that is correct but the reason we address this issue is because the committee seems interested in it. Every time the question is asked so we bring the information forward each time.

That concludes what I have to say. Tilda, I turn it back to you.

MS. LIU: All right. Thank you. Caudle.

DR. BONACA: I'll take just another second to make a correction to my previous announcement of the Red Line. I found additional information. The Red Line is closed between Dupont Circle and Van Ness but is open in other areas and they have a bus service going from one station to the other. The problem is only for those who have to go through that track of road.

MR. JULIAN: That's good news.

DR. BONACA: That is better than what was given to me before that I announced.

MS. LIU: Well, Dr. Bonaca, thank you for that wonderful news. I feel so much better now.

DR. BONACA: With that --

MR. MACFARLANE: Do you if it's in both directions?

DR. BONACA: It sounds as if both

directions are closed but they have a bus service.

MS. LIU: Thank you again, Caudle. Moving on to Section 3 of the SER. I would like to summarize first that, again, the staff found that the applicant met the 10 CFR Part 54 for AMPs and AMRs. In the SER Section 3.0.3 is where we discuss the AMPs.

DR. KUO: Please speak louder.

MS. LIU: Okay. Thank you. Sections 3.1 through 3.6 is what you see in the application and that is how the staff presented in the same order in our SER as well. Can everyone hear me better now?

DR. KUO: Louder.

MS. LIU: Maybe it's the mike. Thank you, Ken. Moving on to GALL review and audit. Again, this is the first pilot that we fully utilized consistency with GALL audits for AMPs and AMRs. These audits were conducted on site as SNC headquarters in Birmingham, Alabama. The staff's review process is described in SER Section 3.0.2.

I want to give you another perspective on how we decided which ones were going to be GALL audited. The first is, of course, being consistent with GALL and that there should be no associated emerging issues or interim staff guidance on the development. In the case for Farley past precedents

was not used for the review by the audit team.

Continue on the review and audits. The audits consisted of NRC staff and contractors and a site specific audit plan was developed and used to conduct the AMP and AMR audits. The AMP audit was a week in length. The audit team evaluated the AMPs that are consistent with GALL including those with the exceptions and enhancements. Again, this is documented in staff's SER in Section 3.0.3.

The AMR audit was about a week and a half in length. The staff reviewed those AMR line items are consistent with GALL and for both AMP and AMR audits the staff performed extensive in-house review prior to going on site at the applicant's Birmingham's office.

DR. WALLIS: When you said they are consistent with GALL, does this mean they had a C+ grade or do they get an A grade? How good are they? Are they barely consistent or do they go way beyond what is necessary?

MS. LIU: The applicant's claim is consistent.

DR. WALLIS: They are barely adequate then?

MS. LIU: I believe Dr. Ken Chang will

discuss that further later on.

DR. CHANG: What Tilda say is the applicant claim that these AMP are consistent with GALL. The other team's job is to go there to dig into the antenna documents, the basis documents, supporting references, calculations, etc., to verify what they say consistent with GALL is whether that is A+ or C- and we find most cases that GALL is B+.

DR. WALLIS: B+.

DR. CHANG: Above.

DR. WALLIS: Above B+.

DR. SHACK: On your previous one when you said that past precedents is not used for FMP review, that's strictly for this audit. I presume when you're writing the SER you do go back to past precedents but that is strictly for the audit?

MS. LIU: That is correct. In Farley's case because Farley was very kind we asked them to participate in the audit process, but the time frame was very short so Farley did not have the opportunity to conduct a thorough review to prepare that for us so we agreed in the case for Farley, the three pilot plants, Farley being the very first pilot, Farley we denied past precedent for the purpose of the audit but for the other two --

DR. SHACK: Okay. So this won't be practiced in the future?

MS. LIU: Correct. Correct. For all the others after Farley past precedents will be used.

DR. KUO: If I may, Tilda, this is an area that we try to explain the GALL scope. What we think is that, you know, with those positions that staff previously approved that we could incorporate this experience into GALL but because Farley was the first pilot plan and the time was short, they were not able to compare their program with the past staff approved positions so they said no, we are not going to do that. We just look at the GALL.

However, for those positions where we had the previously approved positions, they would have to provide the detailed description of the program in their application so they are just not taking advantage of the so-called previously-staffed position.

DR. CHANG: To support PT's statement, in the subsequent audits following Farley it's about evenly divided. Maybe two or three they use past precedent. Two or three they don't use past precedent. Regardless of whether they use past precedent or not, past precedent is just a road map to

direct staff's attention to say, "Hey, this is our basis. We say everything. We quote past precedents."

But the audit team cannot rely on the past precedent to say, "Since there's past precedent, we don't review it." We also go in there to review the assumptions, the conditions, the limitations, all this are consistent with GALL. It just provide us a direction so we just don't look all over the place. We look focused.

DR. SHACK: How do you cite past precedent? Do you really say in the SER for Hatch you --

DR. CHANG: No. The past precedents, the utilities and the applicants normally put in the book called past precedent book. In the past precedent book they pointed out what are the past precedent book they pointed out what are the past precedents. How many plants did you use as the directions to pick past precedents.

When they pick one they don't go to the next one so they each plan may have five plants they pick past precedents from. You go to the past precedent book and you find out and if you go into the past precedents SER you find the justification adequate. You quote that. That becomes your basis of

review and conclusion.

If you don't find that adequate, you go to the backup justification like RAIs, like other things. I don't know what other things yet but you look into mainly RAI process to see whether the question was discussed and how it was finished and you use that as a basis.

DR. WALLIS: Do you ever find anything wrong with GALL? I mean, GALL is treated as absolute gospel. Is it really as good as that? Aren't there some times when you question GALL itself?

DR. CHANG: We treat GALL as a recommendation, as a guideline, especially for somebody like me joining NRC only three years ago. I just put my industrial hat together with the regulatory hat and we conduct the audit in that way so we do impose regulatory check and technical check.

DR. KUO: And, Dr. Wallis, to answer your question, yes we did define a few areas that the GALL was not complete. We are updating it and we are trying to improve.

MS. LIU: Okay. Moving on to slide No. 26 on Aging Management Programs. There are a total of 22 Aging Management Programs associated with the Farley review. After 22 nine are considered common AMPs and

13 are considered component and structural group specific AMPs.

Of these 22 AMPs eight of them are considered existing AMPs, five are enhanced, and nine are new AMPs. In terms of GALL consistency eight of these AMPs are considered consistent with GALL and of those eight two are new AMPs for Farley. There are five AMPs that are consistent with GALL but with enhancements and five with exceptions. There are four AMPs that are new AMPs that are not consistent with GALL and they are also plant specific AMPs.

MR. LEITCH: One of those new Aging Management Programs, and I guess it's really a question for the applicant, is the External Surface Monitoring Program. That might be one to conclude that there was no such program. I would hope the answer is that there has been pieces of that perhaps not formally documented and this is assembling and formalizing such a program. Is that a correct assumption?

MR. MACFARLANE: Is your question concerning how we do that in current space?

MR. LEITCH: Yeah, right. Is there an external surface monitoring program now?

MR. MACFARLANE: Not in the context of the

10 elements for license renewal. There is system engineering walk-downs and similar types of activities that are currently conducted at the plant. In reality it's kind of a day-to-day thing as well as if you come across something that is in a degraded condition you write a condition report to get it addressed. The renewal process what we had to do there was do a little more formal program and also to make it more rigid in terms of what areas are looked at to make sure all the areas are covered.

It pulls in elements from existing programs and will create some new things that will go into it to encompass the entire scope that follows into renewal. So the answer to your question is there is things going on in current term space but there is more to the renewal program than what we are doing in current terms so it's a new program.

MR. LEITCH: Okay. Thank you.

MS. LIU: The next slide is dealing with examples of AMPs with GALL deviations. I will now turn over the presentation to Dr. Ken Chang who was the team leader on these GALL audits. He will be sharing his insights and findings associated with these audits.

DR. CHANG: Thank you. My name is Ken

Chang again. Before I go into the examples I would like to give a little introduction of how the audit teams are formed. I think I gave one before. If not interested, I'm not going to talk about it. I'll move right into the examples.

We pick three examples to discuss in detail here. One is Fatigue Monitoring Program. We say it consistent. Why do we talk about some programs consistent with Gall? Because this program interest many people including myself and it's so complicated but it's so beautiful, so beautiful that I like to talk about it.

The second one is One-Time Inspection and the other one is Non-EQ Cables in Instrumentation Circuits Programs. Those are with exceptions, with enhancement, and enhancement and exceptions.

Talking about the Fatigue Monitoring Program it's a new program. It will be consistent with GALL when fully implemented and specific components included in this program are listed. The top six, four of them are exactly the same as NUREG/CR-6260. Two are reasonable substitutes for the two components in NUREG/CR-6260. Why don't appear exactly the same? Because the plant is not the same.

In the NUREG/CR-6260 the sample plant was

Westinghouse four-loopers and finally the three-loopers. You pick the comparable component in the systems which sees the similar transients is loading so we picked those. I don't mean we. I mean applicant picked those. In addition, this applicant did more than 6260 requires because it also monitors RCL.

It also monitors other Class 1 piping greater than one inch in diameter including RHR which is substitute of the NUREG/CR-626-. Also other Class 1 components as they see fit. When I say when they see fit means they see high usage factor, fatigue damage. That's a very conscientious decision. So go beyond 6260 which is the basis of the GALL.

Farley is currently using cycle counting method for counting the fatigue loading. That cycle counting is not manual counting. They consider both manual counting and automatic counting. Within the automatic counting currently they track 17 locations and will be expanded to include 12 more locations for a total of 29 locations.

In the manual counting currently there are three and they are going to add in two so there will be five so all together it's 34 monitoring locations. That's plenty. That's more excessive than most of the

plants I know.

MR. LEITCH: It looks like a good program going forward but to they have good data from the beginning of plant operation or is that just an estimate or go back through the records or how do they come up with that?

DR. CHANG: Let me go one line more on my slides.

MR. LEITCH: Okay.

DR. CHANG: But this cycle counting method would be modified to use fatigue monitoring software which everybody knows is the Fatigue Pro, Rev. 3. In order to use Fatigue Monitoring Program you need to know the past, current, and future. Also you need to know the transfer function.

So for the past it depends on the analysis and estimates. You put an estimate value for the past. As technology advances, you may modify and perform more additional analysis so this assumed value conservative value, can be modified to benefit more to give more room.

DR. WALLIS: Does this count the cycles and assumes that each cycle is the same?

DR. CHANG: No.

DR. WALLIS: Aren't some cycles more

intense than others?

DR. CHANG: Right now it's counting cycles but when they implement Fatigue Pro, Rev. 3 it's a Fatigue Monitoring Program. It records Data T, Data P, how many times, ramp, how fast the transient is, flow rate, all those parameters. It's sophisticated. Previously other plants like Ginna has approved similarly. They also go the full nine yards.

About the past, some critical fatigue systems like surge line, like the 88-08 lines -- I'm not following this, sorry -- they have a recorded data from April '94 to October '95 for the surge line recorded. They have temperature data, transients, cycles, everything. That is the basis of generating a Westinghouse generic WCAP for fatigue and pressure surge line reports.

Also from that monitoring it created modified operating mode to improve the system performance. They call that modified steam bubble, heat-up and cool-down. You implement that operating mode trending less cycles. Trending is less severe. They are doing that. I'm sure you're still doing that, right?

So by reviewing that auditing finds three comments and those three comments are implemented in

a basis document as of now. It's good for one but other team still find something.

They reduced stress-based on-line fatigue monitoring on the surge line and the low head pressurizer including stratification as we talk a little less. They also evaluated six locations for the environmental impact on fatigue. That's quite up to date. They used FEA methods for fatigue lab reduction factor and used conservative numbers to define the limiting case. All these are very good.

From operating experience everybody know the IE Bulletin 88-08 started from the ECCS safety injection line to the loop B of Unit 2 at Farley. Since then they have a very accurate cycle counting and now they plan to implement the fatigue monitoring software so all this will be implemented so I believe -- the audit team believe this program for implementing will be totally agreed, totally compliant and consistent with GALL.

The next program I would like to talk about is One-Time Inspection. It's a new and plant specific AMP. I forgot to mention at the beginning the audit team is only auditing 17 out of the 22 programs. The audit team is only responsible for 17 of the 22 AMPs.

But since this is the first time the audit team goes out there, we take the liberty of looking to all 22 programs but out of five programs we look at, only four have review purpose only for reference. It's not for using in SER. Whoever responsible for that's the Division of Engineering. They are responsible for input into the SER.

The One-Time Inspection Program is addressed in commitment No. 10. The One-Time Inspection Program selects and inspects representative locations based on combinations of applicable material, environment, and aging effect, MEA. We use acronym MEA. It's normally MEAP but this time this is a program.

The purpose of this One-Time Inspection is for three purposes. One is used for location where aging effect is not expected to occur such as used for water chemistry control to verify that corrosion does not occur. Another purpose is to validate the effectiveness of other credited AMPs such as fire protection and Water Chemistry Control Program. We used the One-Time Inspection to verify the effectiveness of other programs used to manage aging. One-Time Inspection is not managing aging. It's to verify it's effective.

Another purpose is for locations where aging is expected to progress very slowly for any location which to manage the change of material property, loss of material which normally occurs very slowly. That One-Time Inspection is used to verify that.

DR. WALLIS: Very slowly means nothing significant happens in 40 years or something?

DR. CHANG: Not significant up to the point of inspection.

DR. WALLIS: From the beginning of operation?

DR. CHANG: From the beginning of operation to the point you do the One-Time Inspection.

DR. WALLIS: So we're talking about decades.

DR. CHANG: Yeah, yeah. Next slide, please.

DR. SHACK: What's the basis of choosing the One-Time Inspection to validate the effective of accredited AMP? Presumably if you've got a GALL compliant AMP you don't have to validate it. You guys accept it.

DR. CHANG: In principle it's true but if you see how many areas that this One-Time Inspection

is applied to, then you say it's beyond that. Even when GALL says aging is not significant, you use that to verify it is not significant.

DR. WALLIS: Because it's not expected to occur.

DR. CHANG: That may be true.

DR. KUO: Actually, even in GALL programs the combination -- I mean, in many areas the combination of the two is the acceptable program like water program to control corrosion and all that. The GALL actually says you have One-Time Inspection to verify the effectiveness of the program.

DR. CHANG: Okay. So the next slide presented a number of components in different systems that One-Time Inspection is applied. This is only a sample population and there are dozens more which is not here.

DR. BONACA: Isn't this a scope significantly larger than what we have seen in some other unit?

DR. CHANG: I can't speak to that.

Mike, do you have anything you can say about it?

MR. MACFARLANE: In my estimation I would say no, it's consistent with what has been done on

previous applicants. The spray head issue has been a common issue on Westinghouse PWRs. Small bore butt-welded piping is another issue that is pretty consistent.

DR. BONACA: I was commenting not on this list but on the statement by the presenter that there is a long list in addition to this.

DR. CHANG: Maybe this long list belong to every plant.

MR. MACFARLANE: What you see a lot in One-Time Inspection is the staff is requesting One-Times for programs that are preventative in nature. In other words, those programs don't really do inspections like you're not going to see a One-Time trying to verify a ISI inspection but you'll see it trying to verify water chemistry is adequate.

Typically when -- we were pretty aggressive in trying to use where we had operating experience to not do One-Time Inspection so we made an attempt to keep this population to a reasonable level. Some cases we won those arguments and in some cases we did not.

DR. BONACA: Now I also remember some applicants use the strategy of using existing programs to perform the function of a One-Time Inspection.

They simply say, We will perform an inspection under the ISI Program," but it's still a One-Time Inspection identified as such.

DR. CHANG: All right. Thank you. And the example I would like to bring up is the Non-EQ Cables Program. It's a new program that will be consistent with GALL with exception. The exception is the Non-EQ cable used in circuit with sensitive high-voltage low-level signals are tested in accordance with the alternate XI.E2 program.

This to me doesn't seem to be an exception. It's just an acceptable alternative. It's recognized. Through the audit we are able to find two things that need to be changed to make this program really consistent with GALL. One is the program itself originally said you test selective sample. GALL requires that you test all cables.

The GALL apply this program to the cables and connectors. Originally the program only includes cables, no connectors. We also change the basis document and necessary documents to include this change. These are two changes identified by the audit team and it's in the program now.

Before I turn it over to the Reactor Vessel Surveillance -- oh, okay.

MS. LIU: Thank you, Ken. I want to brief the subcommittee on this AMP because we had a license condition associated with it as I mentioned earlier which resulted from the staff's review of the AMP. The Reactor Vessel Surveillance Program is an existing AMP that is consistent with GALL with one exception. The single exception is the proposed surveillance capsule withdrawal schedule. GALL specifies that all remaining capsules are to be removed at a 60-year fluence and alternative dosimetry is to be installed.

For Unit 1 at Farley SSE has removed one capsule at a fluence approximately equivalent to 60 years. For Farley Unit 2 SSE will remove one capsule at a fluence approximately equal to six years. Therefore, for each unit one capsule will remain in the reactor vessel until fluence of approximately six years.

The future action is addressed by commitment No. 18 in the Appendix A of the SER. Furthermore, the applicant committed that for each unit alternative dosimetry will be installed.

DR. WALLIS: Do we know what kind it is, what kind of dosimetry?

MS. LIU: SNC, would you respond to that?

MR. MACFARLANE: The plans are to -- it's

a Westinghouse design. It's external dosimetry.

DR. WALLIS: Backed by calculating?

MR. MACFARLANE: That's my understanding. It's just validating the fluence levels that it's seeing that are consistent. They are monitoring for change.

MS. LIU: I believe Lambros Lois would like to address this issue.

MR. LOIS: My name is Lambros Lois, Reactor Systems Branch. I've been doing the fluence for vessels for quite a while. Actually we have developed computational tools which are quite adequate to predict fluence quite into the future. Although it is desirable to have additional dosimetry to verify actually what the calculations will show, we have quite a bit of confidence.

Regulatory Guide 1.190 which was published in 2001 actually requires that the calculations -- not measurements but calculations be used for the predictive capability, the prediction of fluence in the future. I hope I've answered the question.

DR. WALLIS: Do you have to have some experimental verification of this on the outside?

MR. LOIS: Yes, we do have continued verification of that.

DR. SHACK: Why is GALL so dogmatic about removing all the capsules at 60 years since we hear stories at least that somebody might come in looking for another 20?

MR. MEDOFF: This is Jim Medoff. I'm with Materials and Chemical Engineering Branch. For the Farley units that was the one exception where they did not agree that to take out the fifth capsules and put the remaining capsules in storage.

What they did do is provide us with an updated reactor vessel surveillance capsule removal schedule and demonstrated to us that the removal of the 6th capsules for each unit would be done at approximately the 80-year fluence equivalent so that if they came in for another proposal for renewal that they would have data that would be applicable.

MS. LIU: Thank you, Jim. Therefore, the license condition, as he stated earlier, is to continue meeting the ASTM standards and that for any changes for the capsule withdrawal schedule storage requirements must be approved by the staff.

Slide No. 34, this is NiCrFe Component Assessment Program, otherwise known as the Alloy 600 program. This is a new AMP. This program will include nickel-based alloy RCS boundary components

with no potential susceptibility to primary water stress corrosion cracking.

Farley has committed by Commitment No. 11 in the Appendix A to the SER that you will continue participation in industry initiatives such as Westinghouse Owners Group and EPRI-MRP. The susceptibility rankings and program inspection requirements will be consistent with the latest version of the EPRI and Materials Reliability Program safety assessment.

At this time I want to turn over to Ken. He would like to address certain AMPs that might be to your interest.

DR. CHANG: In the earlier presentation some discussion already had on some of my backup AMP slides so I would like to go to the backup slide 76, Water Chemistry Control Program. Early SNC has indicated Water Chemistry Program has an exception. The AMP addresses performance monitoring while GALL emphasize on some hydraulic performance testing.

I have to say something why it is acceptable. The audit team reviewed the Water Chemistry Control Program TR 107396 and also reviewed the component cooling water pump surveillance test results, heat exchanger condition reports, and the

history of performance, and the FNP Mechanical Operating Experience reports. Reviewing those we find that the AMP based on performance monitoring is adequately managing these aging effects. On that basis we accept the exception.

Let's go to backup slide 78, flow FAC program. In addition to all the discussion held, the audit team went into the operating experience and found that through the FAC program which is in line with the IN 2001-09, the program recommended eight components for Unit 1 to be replaced in IR18 and one component and 25 feet of piping on Unit 2 to be replaced during 2R16. This gives evidence that the FAC program the applicant implementing is working, at least find the things they want to find, find the things they should find.

DR. WALLIS: And taking appropriate action.

DR. CHANG: Yes, naturally. Replacement is appropriate action. Now, that means they are sincere about implementing effective Aging Management Program.

Let's go to backup slide No. 82, fire protection system. A question was raised regarding the acceptability of the 18 months interval. The

audit team reviewed applicant's basis document, the plant operating experience, and the fire surveillance procedures. On the basis that these aging effects occurs over a considerable period of time, the staff judged that 18-month interval would be sufficient to detect aging effects. On that basis, we say the 18-month period is acceptable. And I have --

DR. WALLIS: What does this have to do with 50 years?

DR. CHANG: That's 50 years. That's enhancement. They put four different enhancement on the program to make it better.

DR. WALLIS: That's an awful long time to wait.

MR. SIEBER: That's part of the code for sprinklers.

DR. CHANG: At or before. At or before.

DR. WALLIS: Nothing happens to sprinkler heads before 50 years?

DR. CHANG: After 40 years you don't have to inspect and that is in the extended period of operation.

MR. SIEBER: NFPA code. It's in the code.

DR. SHACK: That makes you feel a lot better. Doesn't it?

MR. SIEBER: The sprinkler will last longer than we will.

DR. CHANG: We go by the rules. Okay. That's all the backup slides I want to bring up for the Aging Management Program.

DR. WALLIS: So heads are made of different metals?

MR. SIEBER: Yes.

DR. WALLIS: All kinds of things could happen if you have a leak. But, anyway --

MR. SIEBER: If they fail to put out fires.

DR. CHANG: I'm not either but I'm just looking into what I should look into.

Okay. Back to you.

MS. LIU: Okay. Thank you, Ken. Moving on to AMR results on Section 3.1, this is the reactor systems. Reactor systems include vessel, internals, RCS and connected lines, as well as steam generators. The staff concluded that the aging facts associated with reactor systems will be adequately managed through the period of extended operation. Issues requiring further evaluation in GALL were evaluated by the audit team and found to be acceptable.

I will once again turn over the

presentation to Dr. Ken Chang who will discuss his review and findings associated with the AMR results of the reactor systems.

DR. CHANG: For the AMR part, I just want to mention two examples which I think is of significance. One is loss of fracture toughness due to thermal aging. GALL requires for CASS material it's either enhanced volumetric inspection or flaw tolerance evaluation needed to be performed. That is GALL recommendation. Sorry, I did say requirement.

The applicant originally want to credit leak before break analysis for the renewal period as the flaw tolerance evaluation. The audit team noted that leak-before-break analysis and flaw tolerance evaluation they both using pressure mechanics methodology to evaluate crack propagation. But these two analyses or two programs are for the different purposes.

Say like leak before break in the mid-'80s is for the elimination of protection devices like, wood break strains, jet shearing, and those for that purpose. It's not really evaluating how the crack propagates. You just want to say it's safe.

That's the whole purpose, but flaw tolerance evaluation is for different purposes and for

different purposes, for different initial flaw, for different load combinations, for different acceptance criteria so they are different animals. You cannot use the leak-before-break analysis, fracture mechanics analysis just to demonstrate it's a flaw tolerance evaluation.

After we were through several discussions, the applicant brought into argument and now by letter dated August 19 the applicant revised and committed to follow the GALL requirements.

DR. SHACK: I can't remember on the age-cast stainless steel, what is the flaw tolerance acceptance criteria? Is it gross failure or does it pop through the crack?

DR. CHANG: I would ask Robert Hsu to stand up and explain.

MR. HSU: Robert Hsu, License Renewal. The acceptance criteria is in ASME Section 11 and I think Appendix C have described based on the current ASME code you can have up to 75 percent wall thickness.

DR. SHACK: Okay. It's the 75 percent criterion.

MR. HSU: Yeah.

DR. WALLIS: Seventy-five percent through

wall?

MR. HSU: The rule on that is go through wall based on the ASME code. Only go to 75 percent.

DR. SHACK: Well, it's clearly very different than leak before break.

MR. HSU: Leak before break allow run through completely.

DR. WALLIS: But it didn't break.

DR. CHANG: As long as it's only a leak, drips not break.

DR. SHACK: No drips.

DR. CHANG: If you perforate it, it will just drip.

MR. SIEBER: Drip before break.

DR. CHANG: The second item worth mentioning is under the crack initiation and growth due to cyclic loading or stress corrosion cracking the staff approved Farley's risk-informed ISI program in March of 2004. We questioned into that, "What do you use risk-informed ISI to select the location or to eliminate inspection?"

The SNC respondent is saying we only use this to select location. We do not eliminate location. Then we continued to ask, "Where do you inspect for small bore volumetric inspection?" They

responded in July '04, "We inspect the 2X3 drain connection on the normal letdown line by UT," which is a form of volumetric inspection. Those are --

DR. WALLIS: That's the only thing they inspected?

DR. CHANG: That's through the risk-informed ISI process to identify the most susceptible, most critical location. We don't judge whether it's adequate by one or two or three.

So back to you.

MS. LIU: Thank you again, Ken. Moving on to Section 3.4 -- I'm sorry, 3.2 ESF systems. ESF systems include containment spray, isolation, and ECCS. As you can tell from the slide, we have a total of four AMPs managing ESF systems. Again, the staff concluded that the aging effects associated with the ESF systems will be adequately managed by these AMPs during the period of extended operation.

DR. WALLIS: There's nothing much happening on the external surfaces of these. Nothing much should be happening at all.

MS. LIU: Correct. Moving onto Aux Systems, Section 3. --

DR. WALLIS: Unless there's borated water leaking and hanging around and cooling down.

MS. LIU: Section 3.3, Aux Systems. There are 23 plant specific systems associated with the Aux Systems. For those there are 11 AMPs that manage aging effects for the Aux System components. Once again, the staff concluded that the aging effects associated with auxiliary systems will be adequately managed during the period of operation.

Moving onto Section 3.4, Steam and Power Conversion Systems. These systems include main steam, feedwater, steam generator blow-down and so on. There are a total of seven AMPs associated with steam and power convergence systems in terms of Aging Management Programs. Once again, the staff concluded that the aging effects associated with these will be adequately managed.

3.5, Containment Systems. Containment Systems include PWR concrete containment, aux building, diesel generator, and so on as you can see from that list. There are a total of six Aging Management Programs, four containment systems. Once again, the staff concluded that these aging effects will be managed by the associate AMPs during the period of operation.

This slide we have the aging management of in-scope inaccessible concrete. As you can tell from

this table, the below-grade environment at Farley is nonaggressive and there are no history of aging degradation or failure of concrete components exposed to a below-grade environment. You can tell from the pH level, chlorides and sulfates, they are all within the limits that are considered nonaggressive.

DR. BONACA: It looks like distilled water.

MS. LIU: Right. I want to point out for you at the phosphate level is .03 ppm sample from the service water pond. The last sample day for the phosphate was March 11th of this year.

MR. SIEBER: They must not grow anything there. No fertilizer.

MS. LIU: Sampling is not performed on a routine basis and the service water pond is the source of water for the service water system. The structures exposed to pond water are service water structures and other structures are exposed to ground water.

DR. WALLIS: Is this the one with the clams in it?

DR. BONACA: Yes, live clams.

DR. WALLIS: They eat the phosphates.

MS. LIU: Possibly. And there was no detectable phosphate in the ground water samples.

Finally, Section 3.6, Electrical Components. There are 10 component types subject to AMR. The AMPs that will be used to manage the electrical components are non-EQ Cables Program, External Surface Monitoring Program, and Buried Piping and Tank Inspection Program.

Once more, the staff concluded that the aging effects associated with electrical components will be adequately managed during the period of extended operation.

Moving on to TLAAs, I want to summarize first by saying that the staff found the applicant TLAAs met the requirements of Part 54. The TLAAs include five sections as you can see from the slide. On Section 4.2, Reactor Vessel Neutron Embrittlement, there are five analysis affected by neutron irradiation embrittlement and they are neutron fluence, upper shelf energy, PTS, adjusted reference temperature and P-T limits.

For neutron fluence the applicant's analysis methods used to calculate the Farley neutron fluence values as projected through the end of the period extending the operation follows the guidance of Re Guide 1.190. On reactor vessel upper shelf energy, as you can tell from this table --

DR. WALLIS: These are your numbers?

MS. LIU: That is correct.

DR. WALLIS: What are Farley's numbers?

MS. LIU: If you look at the table, Dr. Wallis, the table shows the staff calculated value. But for your convenience, I have also listed here on this --

DR. WALLIS: They used it on bullet 2?

MS. LIU: No, on the same slide if you look at bullet -- yes, bullet No. 2, as you stated, the applicant's values are listed there as well. As you can tell, the values are very close between the applicant's and the staff's.

DR. WALLIS: They all use the phone number.

DR. KUO: I hope so.

MS. LIU: Okay. Moving onto PTS, the limiting belt-line materials at Farley Unit 1 is the lower shell plate and for Unit 2 is the intermediate shell plate. Again, for Dr. Wallis, the table list staff calculated values.

As you can tell, they are all within the acceptable range. Again, the applicant's values are 191 and 208. Again, they are very close to what the staff has calculated it. These values are based on

the fluence values for clad-to-base metal locations of the reactor vessels. We used the latest report surveillance capsule data for Units 1 and 2.

Moving onto adjusted reference temperature. This table list, just for your information, a comparison of the values at 1/4 T and 3/4 T locations for adjusted reference temperatures. I have listed there for you both the staff calculated value as well as the applicant calculated value. Again, the values are very close between the two parties.

On P-T limits Farley's 54 effective full power P-T limits were for this based on an NRC approved PTLR process. The staff approved the applicant's PTLR by an SC dated March 31st of 1998 which allowed the applicant to generate the P-T limit curves for a period of extended operation without the need for a licensed amendment for the curves.

Farley's tech spec requires that the applicant submit the PTLR to staff for docking purpose only when a new fluence period occurs or when it revises the supplement to PTLR. The applicant will generate the PT limits for the period of extended operation in accordance with the NRC approved Farley PTLR.

Moving on to Section 4.3, Metal Fatigue. You may wonder why flywheel is listed here as well as containment tendon pre-stress. This is the way that the applicant --

MR. SIEBER: It's always been there.

MS. LIU: Okay. Because I had a staff member to ask why are they listed here and I want to prepare the answer to that. Moving on to the next slide, slide No. 54.

MR. LEITCH: Just a minute. Metal fatigue, charging nozzle.

MS. LIU: Are you talking about slide 51?

MR. LEITCH: Excuse me?

MS. LIU: This is slide No. 51, Dr. Leitch?

DR. WALLIS: No, the next one.

MS. LIU: The next one. Okay, 52? Okay. I'll be going over that.

MR. LEITCH: Okay.

MS. LIU: Fatigue of ASME Class 1 components. The reactor cooling systems components at Farley are designed to Class 1 requirements of the ASME codes. The applicant's evaluation of environmental effects indicated that two components may exceed the fatigue cumulative usage factor of 1.0.

The two components are charging nozzle and RHR safety injection nozzle to the RCS cold leg.

DR. WALLIS: Why is that so big to fatigue? Is it used that much?

DR. CHANG: The applicant's calculation on the charging nozzle and the RHR SI nozzle is based on a conservative assumption of FEA equals 15.35 which is extremely the highest value. When you use a real value those numbers will come down.

DR. SHACK: He's asking why you do recycling there.

DR. WALLIS: Charging nozzle is used quite a lot, RHR/SI. Does it really cycle that much?

DR. CHANG: Charging line based on Westinghouse prime design has about -- sorry.

MS. LIU: John Fair will address this question for the members.

MR. FAIR: Yes, I'm John Fair, the reviewer in this area. The charging line and safety injection line are subject to fairly significant thermal shocks and that's why you have high usage there.

DR. WALLIS: Do you use that safety injection line?

MR. FAIR: Not a lot but it does get

fairly high thermal shocks on it so the design values are fairly high.

DR. BONACA: But isn't the charging nozzle the one that already had a crack in the past?

MR. SIEBER: Yep.

DR. BONACA: I think that's the one, right?

MR. MACFARLANE: The Farley line that initiated the bulletin was a safety injection nozzle that is normally isolated and it was caused by a leaking isolation valve.

DR. BONACA: So it's not the same nozzle?

MR. MACFARLANE: Correct.

DR. BONACA: I thought it was the charging. All right. Do you have full separation of safety injection and charging pumps so they are not interchangeable?

MR. MACFARLANE: Could you repeat the question again?

DR. BONACA: Do you have full separation, distinction between the safety injection pumps and the charging pumps?

MR. MACFARLANE: No, it's a duel use system. The charging pumps are the high-head safety injection pumps but the lines where they actually

inject into the RCS for safety injection versus where they would inject during normal charging are different.

DR. BONACA: They are different. Okay.

DR. WALLIS: Charging is makeup? Is it the same thing?

MR. MACFARLANE: Correct. We normally run an in-flow and an out-flow for chemistry control and inventory control.

DR. WALLIS: But you do have some regularly but you don't use safety injection hopefully.

MR. SIEBER: You use the safety injection pump.

DR. WALLIS: What kind of corrective action are they going to take?

MS. LIU: The applicant's corrective action include one or more of these four options. The first being a further refinement of the fatigue analysis would --

DR. WALLIS: Sharpen the pencils.

MS. LIU: Correct. Or repair the affected locations or replacement of the affected locations and management of the fatigue effects through the use of an NRC inspection program. These are very typical

actions proposed by the other applicants such as Ft. Calhoun and Summer.

MR. LEITCH: The thing that surprises me is this charging nozzle apparently appears to be from these calculations way, way unacceptable at 60 years. We say that prior to entering a period of extended operation we'll decide what to do with this. How do we know it's okay today?

MR. FAIR: Well, what is unacceptable at 60 years is the usage factor with the environmental factor factored into it. We did an evaluation back -- I think we presented it back in about 1995 based on a combination of risk evaluation plus an evaluation of sample plants that the risk for 40 years operation wasn't great enough to require anybody to back-fit for 40 years operation. For the additional 20 years we thought it was worthwhile to reevaluate these locations to make sure they are good for 60 years. But it was a combination of evaluation and conservatisms in the analysis and a risk assessment of the consequences of fatigue failure at those locations.

MR. LEITCH: I guess if you did these same calculations for --

DR. SHACK: Today.

MR. LEITCH: -- today, what kind of a number would you get?

MR. FAIR: One of the things that when they take the conservatisms out of the analysis, I think these type of nozzles if they go to the full limit of doing a finite element analysis, they probably will show that they are well below 1. That has been the experience with other utilities of doing the detailed analysis. They just didn't want to do it at this point in time and that's one of their options prior to the period of extended operation.

DR. SHACK: And your judgment is that if they did the detailed one that would be okay so you're not going to really get too worried about it?

MR. FAIR: Yeah, I think each time we find out that for these particular nozzles they do them using piping analysis rules which use very conservative stress intensification factors. When they go to a full-blown finite element analysis, it takes a lot of conservatism out of those stresses at those locations. If you look at the way the fatigue curve goes, if you reduce the stresses by a factor of 2, you reduce the fatigue usage by much, much greater than that.

MR. LEITCH: I'm just surprised. This

particular issue here is not my field but, I mean, I'm scanning these numbers here and expecting to see something considerably less than 1.

MR. FAIR: Yes.

MR. LEITCH: Instead I see something like 12. I mean, hopefully there's a lot of conservatism there.

MR. FAIR: That's not unusual. A lot of these high-usage locations have fatigue usage factors close to one for the design basis. When you put an environmental factor on top of that, then you get those really high numbers.

DR. BONACA: That raises -- I mean, this is -- I've been thinking about the same issues here and I know some applicants are showing now interest in renewing the license beyond 60 years. I'm asking myself about the issue of fatigue. I mean, these components simply have a life that is limited. One of the options is sharpening the pencil and qualifying the equipment beyond a certain point. How far can you do that? I'm trying to understand this issue of margin. How much margin is really there in components?

DR. SHACK: Well, after you put in the environmental effect and you do the finite element

analysis, you get a number that is probably as far as you can go.

MR. MEDOFF: May I make a clarification here, though? For Part 54 and TLAAs it doesn't say that your TLAA has to remain valid but if it doesn't remain valid you have to propose an Aging Management Program. Even if you don't make the -- if your TLAA is no longer valid or remains bounding, you can still manage through an AMP. Even if they don't meet their CUF for, let's say, an 80-year program, they could still propose an AMP to address the --

DR. BONACA: I was simply raising a question regarding the margin. We can certainly sharpen the pencil and propose an AMP, etc., but you are effectively aging the equipment at some point whatever margin is in them for whatever aging effects, in this case it's fatigue, it will be certainly reduced. The low point is reduced below the level of confidence or comfort that you should be concerned about.

DR. CHANG: If I may, another proof is normally you do stress-based fatigue monitoring on the most critical locations. On Farley the location selected for stress-based fatigue monitoring program is the surge line and lower head of the pressurizer so

obviously the charging nozzles, SI nozzles, are not the most critical location. Just because they did a conservative one-time calculation to get by for 40 years, no. That's why the usage factor is high. In reality the usage factor is not high. Need not to be high.

DR. WALLIS: What kind of environmental effects applies to this huge CUF?

DR. SHACK: Water.

MR. FAIR: Yes, reactor water and oxygen level and the reactor water.

DR. WALLIS: It's the oxygen that does it?

MR. FAIR: Well, there's the argument about that in the ASME code but according to Dr. Shack's report at this point, it's related to the oxygen level.

DR. SHACK: It depends on whether you have carbon steel or stainless steel.

DR. WALLIS: This is stainless steel.

DR. SHACK: Stainless steel, low oxygen water turns out to be quite damaging. We still don't understand exactly why. We keep doing the tests. You keep running them and you keep getting the same answer.

DR. CHANG: But as a first step if you

calculate a reasonable FEN it's not going to be 15.35. Right away you drop your usage factor way down.

DR. WALLIS: I have no idea how much you have to fudge it to bring it down from 15 to 1 but it just sounds like --

DR. SHACK: Well, as John says, the stress goes so nonlinerally that I don't know that the 15 -- you know, that the FEN probably isn't all that unreasonable but you get so much back from the stress analysis.

DR. WALLIS: You know so little about what the oxygen is doing so you have the factor of safety.

DR. BONACA: All right.

DR. WALLIS: I guess we have to trust Dr. Shack.

MR. SIEBER: I do.

MR. FAIR: Yes. I'm trusting him so far.

MS. LIU: Okay. Moving on to slide No. 53, fatigue of reactor coolant pump flywheel. The applicant's fatigue crack growth analysis assume the occurrence of 6,000 reactor coolant pump start/stop cycle through the expiration of PEO, six years, with allowable crack growth of .08 inches. Farley's fatigue analysis for ASA classified components assume 200 plant start-up and trip cycles through six years

of operation.

Based on these assumptions it would take over 30 reactor coolant pump start/stop cycles per plant shutdown to exceed the allowable crack growth of .08 inches. This is beyond the normal number of reactor coolant pumps start/stop cycles that would be expected during any plant shutdown. Therefore, the staff concludes that Farley reactor coolant pump flywheels have sufficient margin against fracture for PEO.

On to fatigue of SME non-Class 1 components. SME Class 2 and 3 and ANC standards require that a stress reduction factor be applied to the allowable thermal bending stress range if the number of full-range cycles exceeds 7,000. Most piping systems within the scope of license renewal are bounded by 7,000 cycles. Sampling was designed for 22,000 cycles.

DR. WALLIS: What does sampling mean here?

MR. SIEBER: Sampling system.

DR. WALLIS: What does that mean?

MR. SIEBER: It's the piping system where you get reactor cooling through a bunch of cells that tells you what the chemistry is.

DR. WALLIS: So you're saying the sampling

system is okay?

MR. SIEBER: They take a sample of --

DR. WALLIS: I'm trying to get the logic, get the connection between the 7,000 and 22,000.

DR. SHACK: Well, they just designed the sampling system to take a lot more --

DR. WALLIS: That's just to say the sampling system is okay. How about the other components? Is it only the sampling system that's okay?

MS. LIU: John, would you like to elaborate on that?

DR. WALLIS: I'm not sure what the logic is. That's all.

MR. FAIR: I think he had the answer correctly. The sampling system was designed for a lot more cycles than the 7,000 so it's okay.

DR. WALLIS: So it's okay. So this answer only applies to the sampling system.

DR. SHACK: No, the other systems are bounded by the 7,000 cycles which is sort of the standard criteria for the 3011.

DR. WALLIS: How many cycles are you going to get in this how many years? How many cycles is it going to be connected to?

MR. FAIR: Let's take -- for these non-Class 1 systems the criteria is looking at the full bending of the piping system like the start-up and shutdown. For most systems they don't cycle them that often so 7,000 is a very bounding number.

DR. WALLIS: How long will they cycle them during the period of license renewal? What is the total of cycles we're talking about? Is it 2,000?

MR. FAIR: Oh, it's probably on most systems on the order of hundreds or less. I'll defer to --

DR. WALLIS: All are different. That's all I need to know. Some sort of comparison.

MS. LIU: Thank you, John. Finally, on the number of thermal cycles for emergency diesel generator air start system that may see 7,000 during the operation. However, the applicant indicated that the equivalent number of full temperature cycles will be less than 7,000.

DR. WALLIS: Is that because they are required to keep testing it and so on?

MR. FAIR: Well, on this particular one the number of times this thing as cycled is going to be more than 7,000 but the applicant actually monitored the temperature swings during the cycling

for this particular line and found that they were much less than the design for full charging so that when they used the code criteria for calculating the equivalent number of full-range cycles it comes out less than 7,000 so it's okay.

MR. SIEBER: What part of the air-start system is the critical part from a fatigue standpoint?

MR. FAIR: I believe it was straight downstream of the compressor. Maybe you could help.

MR. SIEBER: You mean the piping system?

MR. MACFARLANE: The discharge line out of a compressor which gets really hot during a full charge of the cumulator tank.

MR. SIEBER: Okay.

MR. MACFARLANE: And then typically the reason we get these partial cycles is we do -- you know, you get some leakage out of these things and they'll do small makeups into this cumulator so the compressor doesn't run very long. It's a very short cycle and you don't get the heat that you do with a full charge and that's when you get to this equivalent cycle determination. Like you said, we did do testing on it to actually quantify what that was.

MR. SIEBER: Thank you.

MS. LIU: Moving on to containment tendon

pre-stress. This was related to an REI that the staff requested the applicant to provide, minimum required pre-stress enforced for tendon. The applicant's trending analysis provided actual force for tendon and a trend line. The values are based on interpretation from the trend line curve.

As you can see from this table, the trend line values are provided for four years and six years and both of those values are above the minimum required value.

DR. WALLIS: How accurately do you know these tension?

MS. LIU: I would like to ask Hans Ashar to elaborate on that, please.

MR. ASHAR: I didn't hear the question.

DR. WALLIS: Presumably there are many tendons.

MR. ASHAR: Yes, there are.

DR. WALLIS: And there's a variation in this tension. They don't all have the same tension. I am surprised to see numbers here, five significant figures.

MR. ASHAR: Yes. Well, it is calculated that way. I'll tell you what happens is at each tendon inspection there are seven or eight tendons

inspected for liftoff testing. That means they measured the stressing points at those times. They are done every five-year interval so they get a number of readings which are shown in the ASE if you look at the Safety Relation Report on page number --

DR. WALLIS: The average is okay because you are only interested in the total --

MR. ASHAR: No. It is not averaging really. What is being done here is they are measuring stress points at various times. What they did was they did the regression analysis showing the trend line as to what can happen in the future through regression analysis.

DR. WALLIS: My question is the minimum required for a tendon and you've got some sort of average tension on the tendon or stress in the tendon. I presume there is a variation from tendon to tendon so some tendons come below the minimum?

MR. ASHAR: Oh, absolutely. That's what I'm trying to -- if you have a Safety Relation Report with you, I can point out to you what is exactly done there.

DR. WALLIS: Section of the variation and the stress between tendons from tendon to tendon. We don't need great complexity here.

MR. ASHAR: I will show you the readings. On Safety Relation Report whole charge is given for the readings for which this trend line has been -- these are the readings from the trend line, not from individual tendons.

DR. WALLIS: Suppose you have a trend line and you're extrapolating to 1198 on five at 60 years. Is that the average stress in the tendon? Are some of them below 1,000 or something? I don't understand how much spread there is from tendon to tendon and whether it matters or not.

MR. ASHAR: That's what I'm trying to show you. If you have the ASE I can show you very well what the schedule is. These are the schedules shown on the chart which is in the Safety Relation Report.

DR. WALLIS: I don't need that. I just need to know if your criterion is just an average tension or if you're taking account of the various --

MR. ASHAR: Oh, yes. You're quite right. I think what happens here is the minimum required stress is based on the required internal pressure.

DR. WALLIS: Does that have to be in all tendons or is it the average minimum?

MR. ASHAR: It has to be the average minimum.

DR. WALLIS: Average?

MR. ASHAR: That's correct.

DR. WALLIS: That's the question I started with.

MR. ASHAR: The reason is because it's not based on --

DR. WALLIS: Obviously there's a scatter here.

MR. ASHAR: Yes. Right.

DR. WALLIS: That's a pretty ambitious trend line for that data.

MR. ASHAR: Yes.

DR. SHACK: We won't calculate R-squared.

DR. WALLIS: Oh, dear. This must be a materials problem.

DR. SHACK: I put it on a log-log plot and it looks better.

DR. WALLIS: Of course, you've got the black numbers so I can't see them on a blue background. What is your criterion for success? Everything above the red line. Is that it?

MR. ASHAR: That's correct.

DR. WALLIS: So that looks a little more hopeful. Okay. But there's obviously no trend whatsoever in the data after the first one.

MR. ASHAR: Well, that's the reason you need the regression analysis.

DR. WALLIS: Even so. Well, okay.

MS. LIU: Thank you, Hans. Going back to --

DR. WALLIS: Is this standard procedure? Is this just regulatory space you're talking about? This is something that is standard throughout industry when they deal with this kind of stuff?

MS. LIU: Yes.

MR. ASHAR: Do you want me to respond to your question, sir?

DR. KUO: Go ahead.

DR. WALLIS: Is this what they do with bridges and things like that or buildings?

MR. ASHAR: No. I think in bridges because there are separate girders there, what they are doing normally the AASHTO requirement to measure the stressing and 10-year interval or something. Just look at that part of the tendons. Here we have a multiple number of tendons, 200 tendons in vertical direction.

DR. WALLIS: You take a sample?

MR. ASHAR: Yeah, we take a sample, sir. Correct.

DR. WALLIS: Well, okay. Maybe if I were curious I would have to look at all the details and I don't think I've got time.

MS. LIU: Going back to slide No. 55, this is on Section 4.4, environmental qualification of electrical equipment. The EQ programs consist of the GALL program and the effects of aging on the intended functions will be adequately managed for the period of extended operation from the applicant's continued implementation of the EQ program. Again, the staff concluded that the applicant's EQ program is adequate to manage electrical equipment.

Section 4.5, this is where we have other plant specific TLAAs that includes ultimate heat sink silting, leak-before-break analysis, and RHR relief valve capacity verification --

DR. WALLIS: I'm curious about silting. The bottom of the pump silts up but does the top level stay constant?

MS. LIU: SNC, would you like to address that?

MR. MACFARLANE: Essentially it does.

DR. WALLIS: Is there water coming in to keep the level up always?

MR. MACFARLANE: Maybe I misunderstood

your question. The confines of the pond stays essentially constant. It is an earthen structure.

DR. WALLIS: Water comes from a river or something --

MR. MACFARLANE: The water level --

DR. WALLIS: -- until it dries up.

MR. MACFARLANE: Oh, that's true. We keep a makeup to the pool. We do have tech spec limits on what the pond level is and we maintain it actually a given level. When they do this test that's one of the things they do is they regulate that pond level to get it up to a standard point so that when they do the test it's consistent from test to test and then they measure the silting looking at poind depths. A sounding survey is essentially what they're doing.

DR. SHACK: Have you had to dredge this thing before?

MR. MACFARLANE: No. Actually, our testing results show that we do not have a significant silting problem. It just happens we have a calculation that went out and used a 40-year number to look at whether or not it would be a problem and that made it fall into a TLAA space.

DR. WALLIS: A big silting is when you get a flood or something presumably and there are

particulates in the water.

MR. MACFARLANE: In the case of the pond we get outflow of the pond in that situation and the pond would actually fill up potentially and we would have it going out of the spillway the other way.

MS. LIU: Slide No. 57, ultimate heat sink silting. 1325 acre-feet for service water pond is used as the ultimate heat sink in the FSAR. The average measured pond volume is 1418.5 acre-feet. This is taken from 12 sets of data over a 22-year period. That data was taken from 1981 to 2003.

With the 2003 data the increase with time is .054 acre-feet per year with a predicted 60-year end-of-life ultimate heat sink volume of 1421 acre-feet. Again, this is above the 1325 acre-feet used in the FSAR.

DR. WALLIS: This looks like the easiest technical analysis of all.

MS. LIU: Yes.

DR. WALLIS: Understandable at a pretty early stage in one's mathematical career.

MS. LIU: The staff performed an independent regression analysis of the data furnished by the applicant and found SSE statements concerning the regression analysis to be correct that the

ultimate heat-sink pond volume during the period of extended operation will remain above 1325 acre-feet used in the UHS analysis.

I want to point out that the minimum recorded ultimate heat-sink pond volume is 1403 acre-feet. This was based on a 1984 surveillance data. The staff agrees with the applicant's conclusion that existing required pond volume remains conservative for the renewal term and assures adequate ultimate heat sink volume to safely shutdown and maintain long-term cooling. Next one is on --

DR. WALLIS: This isn't a pond that freezes, is it?

MS. LIU: Probably not. It's down south and pretty warm over there.

Moving on to leak-before-break analysis. The applicant's leak-before-break analysis has been redemonstrated and continues to be valid during the period of extended operation. The staff determined that the applicant's reanalysis appropriately evaluated impacts of aging degradation on the perimeters and acceptance criteria for the analysis and demonstrated that the analysis was adequately projected through the expiration of the period of extended operation.

Finally, on RHR relief valve capacity verification calculations. This is addressed in commitment No. 15 in Appendix A to the SER. It states that SNC will update the RHR relief valve flow capacity analysis that utilizes P-T curves as an input to include the calculated 54 effective full power limit curves prior to the period of extended operation.

DR. SHACK: Just before -- I keep coming back to my leak-before-break question. Every license renewal for a PWR is going to come up. We go through this analysis but you are really not quite consistent with the staff branch position on leak-before-break because you have now got an active degradation mechanism postulated in here. I suppose we could give them credit for one mitigating action because they are adding zinc but you're going to have to come up with --

DR. WALLIS: -- is that what it does?

DR. SHACK: -- a position on leak-before-break. Well, it prevents cracking. At least that's part of the theory.

MR. MEDOFF: What's your question?

DR. SHACK: Just how do you credit them for leak-before-break when they don't meet the branch

position on what your need for leak-before-break.

MR. MEDOFF: I'm not the expert in this. My understanding is that the materials in Chemical Engineering Branch of NRR is looking into the impact of stress corrosion cracking on the assumptions made for leak-before-break analysis and how it's going to impact previous approvals granted for pressurized water reactors in the United States. My understanding is Matt Mitchell is the senior engineer that is responsible for that review and I can get more information on that if you need it.

DR. SHACK: I'm actually comfortable with the analysis. I think the cracking is not going to be that extensive. It's not going to grow that fast. Boric acid is a great leak detection system if nothing else.

MR. MEDOFF: My understanding is that is definitely being looked into right now and being discussed with the industry.

MS. LIU: And, finally, in summary we are seeing the conclusion that we mentioned earlier. The staff found that Farley license renewal application has met the requirements of 10 C.F.R. Part 54 in terms of scoping and screening, AMPs and AMRs, and TLAAs.

DR. WALLIS: Did you put up your 60 slides

with no typos? That's a pretty good job.

MS. LIU: Thank you, Dr. Wallis. That concludes staff's presentation on the Farley draft SER.

DR. BONACA: Thank you. I would like to go around the table and see if there are any comments. Clearly this is the draft SER. I don't see many changes coming because they are open items and I thought that both the application and the SERs were high quality. I would like to go around the table maybe and start with you, Jack.

MR. SIEBER: I agree with your conclusions. This is the best one I've seen so far.

DR. SHACK: Yeah, I'll just put in a pitch. Whether you had to twist their arm or something, they did a very nice job on the fatigue program. I thought that was very nice, the fatigue monitoring program. And the discussion in the SER of the fatigue monitoring and the leak-before-break and the various reasons I thought was very good. As I mentioned before, I thought the whole organization of the SER was a very good one.

DR. BONACA: Graham.

MR. LEITCH: I have no further comments. I had a number of questions and I was satisfied with

the answers. I think the application was easy to follow and understandable. I also liked the audit and review report. I thought it was very well done.

DR. BONACA: Rich.

DR. DENNING: Best one I've seen so far.

DR. WALLIS: Does it meet your quality standards?

DR. BONACA: Graham.

DR. WALLIS: Well, I really liked the on-site audits record of that. That really helps me a lot. That really adds a lot to just checking off everything as according to GALL, but when you actually go there and talk to the people and dig in, I really appreciate that.

DR. BONACA: Vic.

DR. RANSOM: The only questions I had were answered during the presentation. It appeared good to me.

DR. BONACA: I agree with the fact that I mentioned before, the Farley application was a quality work and so was the SER. The presentation was very effective. I think, you know, looking at the plant itself there are a lot of initiatives there to maintain it in good condition from the placement of the heads, although there are no indication yet to the

other initiatives they have to maintain it.

Statements of the inspector that the plant looks better today than it looked eight to 10 years ago is also significant. I'm pretty encouraged by this application. I thank both of you and you for the If there are no further comments --

DR. SHACK: Oh, could I ask what the CDF is?

DR. DENNING: Today you mean?

MR. SIEBER: It's a three-loop Westinghouse plant.

DR. SHACK: Nobody knows?

MS. LIU: We can get back to you on that if you would like.

DR. SHACK: I would be interested. Add that to the list of things that really aren't part of the license renewal but we always like to know.

DR. WALLIS: This is a subcommittee so when you finish give us the CDF.

MS. LIU: Okay. Thank you.

DR. BONACA: Okay. Did you get the answer? No. Not yet.

MS. LIU: He's going to get back to us.

DR. WALLIS: You don't know what your CDF is? It must be a very important thing.

DR. BONACA: With that commitment for some information there, I think I will adjourn this subcommittee meeting. Thank you very much.

(Whereupon, at 5:30 p.m. the 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.

Rebecca Davis

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

Farley Nuclear Plant License Renewal Presentation to ACRS Subcommittee

Jan Fridrichsen

November 3, 2004

SOUTHERN COMPANY
Energy to Serve Your World™

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Introduction

- Application and Background
- Description and Features of FNP
- Operating History
- Scoping Discussion
- Application of GALL
- Commitment Process
- Industry Issues

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Application Background

- Application submitted Sep 12, 2003
- Original license expiration:
  - Unit 1 - Jun 25, 2017
  - Unit 2 – Mar 31, 2021
- New Process
  - Consistent with GALL Audits
- Approximately 168 questions including RAIs, Supplemental and Followup

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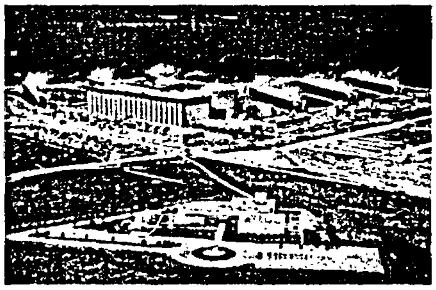
Description of FNP

- Three-loop, Westinghouse PWR
- Bechtel/Southern Company Services-Architect/Engineers
- Initial Ops: Unit 1 1977, Unit 2 1981
- Electrical capacity: 910 megawatts/unit



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Plant Performance – Five Years

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Farley Unit 1	1999	2000	2001	2002	2003
Capacity Factor (%)	97.4	71.5*	87.6	99.0	90.8
Outage Duration (days)	-	82.5*	41.2	-	35.4
Radiation Exposure (dual unit figures) (Rem)	95.2	179.9*	160.3*	48.2	55.5
Farley Unit 2	1999	2000	2001	2002	2003
Capacity Factor (%)	71.7	100.0	78.2*	87.6	100.4
Outage Duration (days)	60.3	-	74.3*	44.9	-

*Steam Generator Replacement

NRC Performance Indicators

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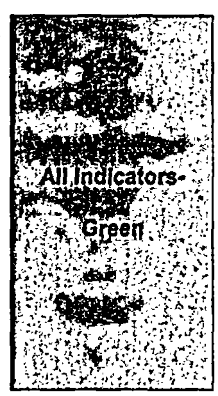
- Initiating Events
- Mitigating Systems
- Barriers
- Emergency Preparedness
- Occupational and Public Radiation Safety
- Physical Protection



Features of FNP

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- Pre-stressed/post-tensioned dry Containment Building
- Safety-related Cooling Water Pond
- Six offsite power sources
- Five Emergency Diesel Generators
- Forced-draft Cooling Towers
- 18 Month Fuel Cycles

Operating History

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- Upflow Modification-1983 (U1)
  - Baffle jetting caused fuel failures
- Cracked tendon anchor head 1985 (U2)
  - Hydrogen induced stress cracking
- IEB 88-08 Pipe Crack U1-Dec 1988
  - Thermal cycling caused by valve leakage
- Zinc Addition project-1994 (U2), 1999 (U1)
  - Dose reduction benefit is evident
  - Reduce stress corrosion cracking susceptibility

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Operating History (cont.)

- Uprated: 1998 Unit 1, 1998 Unit 2
  - –Increased capacity by 123 MWt/unit
- SGs replaced in 2000 (U1)/2001 (U2)
  - –Model 54F (Alloy 690 tubing, SS cruciform support plates, full depth roll)
- RV Head Replacement (Oct '04/'05)
  - –Alloy 690 penetrations without thermal sleeves

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Long Term Operation Focus

- SG replacement
- RV Head replacement
- Cooling Tower replacement
- Dry Cask Storage installation
- Baffle Former Bolt replacement

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FNP Scoping Methodology

- Consistent with past applicants

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GALL Comparison

- SNC maximized the use of GALL
- Some material/environment/program combinations not addressed in GALL
- Plant-specific programs used as needed (or directed by GALL)

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Key GALL Exceptions

- Reactor Vessel Surveillance Program
  - One surveillance capsule (in each unit) will remain in the reactor vessel until approximately an 80-year fluence exposure. (GALL AMP XI.M31 specifies all remaining capsules are to be removed at a 60-year fluence exposure.)

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Key GALL Exceptions (cont.)

- Reactor Vessel Internals Program
  - Consistent with previously NRC-approved programs
  - Participation in industry initiatives to evaluate RV internals aging mechanisms and develop inspection guidance,
  - SNC will submit inspection plan for review and approval at least 24 months prior to period of extended operation.

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Key GALL Exceptions (cont.)

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- Non-EQ Cables Used in Instrumentation Circuits
  - Consistent with previous NRC-approved programs
  - Program based an alternate XI.E2 program

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Key GALL Exceptions (cont.)

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- Water Chemistry Control Program - Closed Cycle Cooling Water
  - Credit EPRI monitoring guidelines (e.g., inspections) in lieu of GALL performance testing for pumps and heat exchangers

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Minor GALL Exceptions

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- Exceptions/clarifications where a GALL Program was utilized were primarily:
  - Use of different or later versions of codes and standards
  - Expansion of a program's scope beyond that described in GALL
  - Use of later NRC guidance

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Commitment Tracking

- Commitment
  - Commitments made through the LRA, RAI and audit/inspection process
  - Tracked with onsite Commitment Tracking System
  - Region II to perform commitment inspection
  - Approximately 130 commitments made to date

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Commitment Tracking System

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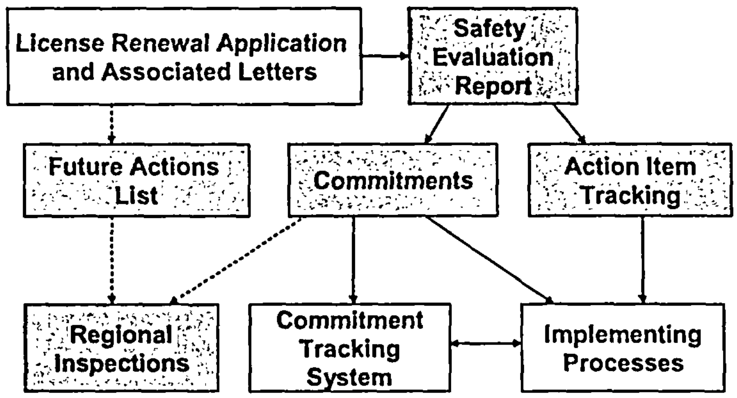

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Industry Issues

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- Bottom Mounted Instrumentation Inspection results (IEB 2003-02)
  - Inspections performed: U1 2003/2004, U2 2004
  - No degradation evident
- VC Summer Inspections (MRP 2003-039)
  - Inspections performed: U1-2004, U2-2004
  - Visual no degradation evident

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Closing Remarks

- Staff process was thorough and rigorous
- Consistent with GALL process added depth and clarity

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Joseph M. Farley Nuclear Plant Units 1 and 2 License Renewal Draft Safety Evaluation Report

Staff Presentation to the ACRS Subcommittee

Tilda Liu, Project Manager
Office of Nuclear Reactor Regulation

November 3, 2004

Agenda

- Overview and Highlights
- Review Process
- SER Section 2, Scoping and Screening
- License Renewal Inspections
- SER Section 3, AMPs and AMRs
- SER Section 4, TLAA
- Conclusion

Overview

- First LRA to use newly revised NEI format
  - Table 1
  - Table 2
  - Standard Notes for tables
- First pilot license renewal review to fully implement consistency with GALL audits for AMP and AMR (new review process)

Staff's Conclusion

- FNP LRA has met the requirements of 10 CFR Part 54
  - Scoping and Screening
  - AMPs and AMRs
  - TLAA

Highlights of Review

- Draft SER issued on October 15, 2004
- No Open or Confirmatory Items
- Efficiencies gained from the new review process
  - Reduction in number of staff's Requests for Additional Information (RAIs)
  - Onsite audits provided direct and more effective interactions between the staff and the applicant, resulted in minimum formal correspondence

RAI Related Statistics

- 163 RAIs issued via 17 letters
  - 62 on scoping and screening
  - 15 on AMPs
  - 70 on AMRs (including 3 from Audit Team)
  - 16 on TLAAs
- Number of RAIs for other LRAs
  - Summer (280), Robinson (360), and Ginna (224)
- 2 meetings and 56 conference calls
- Applicant also provide supplemental information to the LRA, in addition to RAI responses

Highlights of Review (continued)

- 3 license conditions
  - FSAR update following the issuance of renewed licenses
  - Commitments completed in accordance with schedule
  - Reactor Vessel Surveillance Program
    - Continue meeting ASTM E 185-82 standards
    - NRC staff review and approval are required for <u>any changes</u> to:
      - Capsule withdrawal schedule
      - Capsule storage requirements

Highlights of Review (continued)

- Brought into scope and subjected to AMR
  - Additional 10 CFR 54.4 (a)(2) components
    - 8 systems from Auxiliary Systems
    - 3 of which resulted AMR information revised
- 1 AMP added after LRA submittal
  - Plant-Specific AMP: Periodic Surveillance and Preventive Maintenance Activities Program

NRC Review Process

- Scoping and Screening Methodology Audit
- Consistency with GALL Audits
- Table top [in-house] safety review
- Regional inspections
  - Scoping and Screening Inspection
  - AMP Inspection
  - Third (Optional) Inspection

NRC Review Process (continued)

- AMP GALL Audit
  - November 3 – 7, 2003
- Scoping and Screening Methodology Audit
  - November 17 – 21, 2003
- AMR GALL Audit
  - December 15 – 19, 2003
- AMP/AMR Audit Exit Meeting
  - February 14 – 16, 2004
- Regional Scoping and Screening Inspection
  - May 10 – 14, 2004
- Regional AMP Inspection
  - September 20 – 24, 2004, and September 27 – October 1, 2004
- Regional Third (Optional) Inspection
  - March 1, 2005

Summary for Section 2, Scoping and Screening

- The applicant's scoping methodology meets the requirements of 10 CFR 54.4
- Scoping and screening results included all SSCs within the scope of license renewal and subject to AMR as required by 10 CFR 54.21 (a)(1)

Applicant's Revised Scoping Methodology Pertaining to 10 CFR 54.4 (a)(2)

- Initial mechanical scoping criteria for spray interaction for low-energy lines
  - Assumed a spray interaction of 20 ft radius
  - Limited valid targets to only electrical SSCs
- Revised mechanical scoping criteria for spray interaction for low energy lines
  - All fluid-bearing NSR SSCs, provided the NSR components are located in the same space as the SR SSCs
  - Sprays and leaks on mechanical, structure, and electrical SR SSCs, with no limitations on the duration of the leaks/sprays

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.1, Scoping and Screening Methodology
  - On-site audit November 17 - 21, 2003
  - Staff audit and review concluded that the applicant's methodology satisfies the rule
  - RAI
    - NSR criteria pursuant to 10 CFR 54.4 (a)(2)

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.2 , Plant Level Scoping Results
  - Staff identified SSCs that met 10 CFR 54.4(a)(2) criterion and additional components were brought into scope for 8 auxiliary systems
- Section 2.3, Scoping and Screening Results – Mechanical Systems
  - Reactor Vessel, Internals, and Reactor Coolant Systems
  - Engineered Safety Feature Systems
  - Auxiliary Systems
  - Steam and Power Conversion Systems

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.4, Scoping and Screening Results – Containments, Structures, and Component Supports
  - PWR Concrete Containment, Auxiliary Building, Diesel Generator Building, Turbine Building, Other Structures and Supports
- Section 2.5, Scoping and Screening Results – Electrical and Instrumentation and Control (I&C) Systems
  - 10 electrical and I&C commodity groups subject to AMR

Scoping and Screening Summary

- The applicant's scoping methodology meets the requirements of 10 CFR 54.4
- Scoping and screening results included all SSCs within the scope of license renewal and subject to AMR as required by 10 CFR 54.21 (a)(1)

License Renewal Inspections

- Scoping and Screening Inspection
- Aging Management Inspection
- Third (Optional) Inspection
- Commitment Tracking
- Plant Reactor Oversight Process (ROP)

Scoping and Screening Inspection

- Objective: To determine whether the applicant has included all appropriate SSCs in the scope of license renewal as required by the Rule
- Conducted May 10 – 14, 2004
- Concluded that the applicant's scoping and screening process was successful in identifying those SSCs requiring AMR

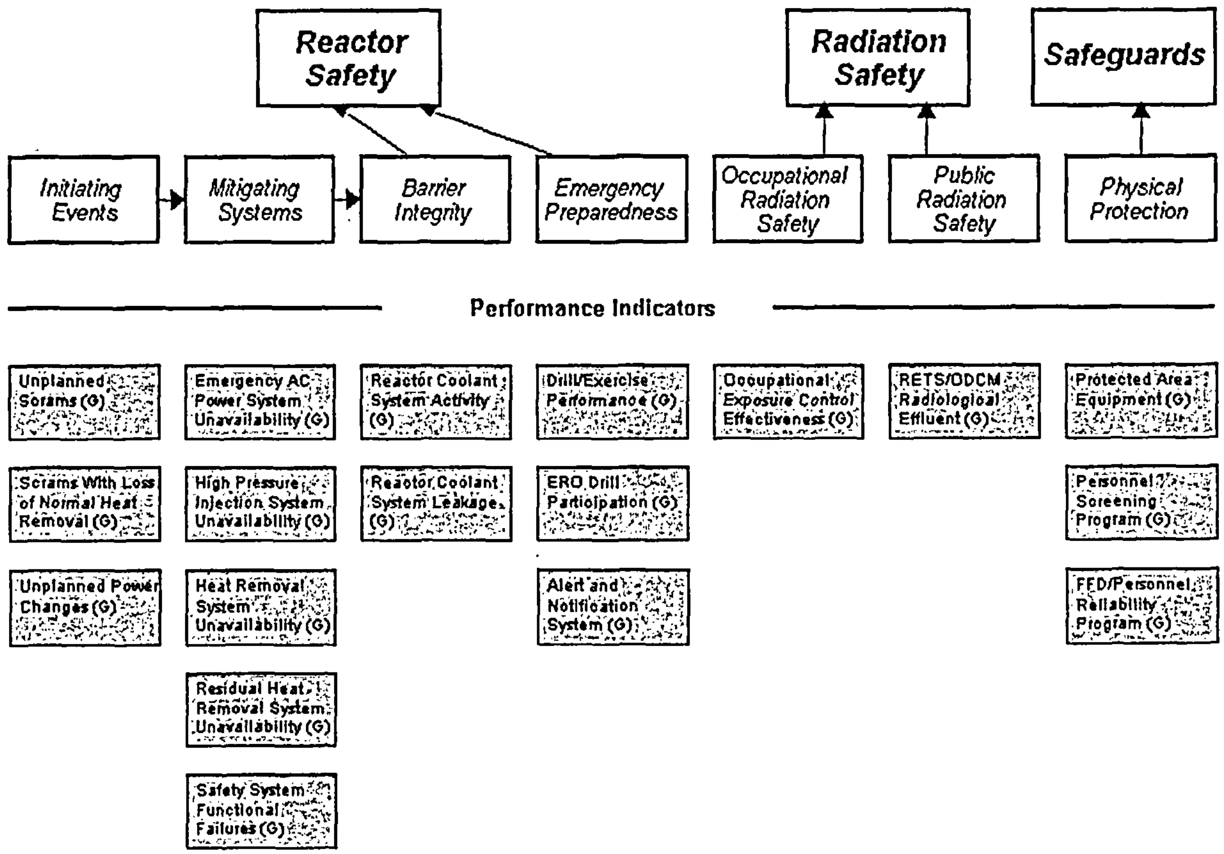
Aging Management Program Inspection

- Objective: To evaluate that existing AMPs are managing current age related degradation
- Conducted September 20 - 24, and September 27 - October 1, 2004
- Material condition of plant was being adequately maintained
- Documentation was detailed and comprehensive

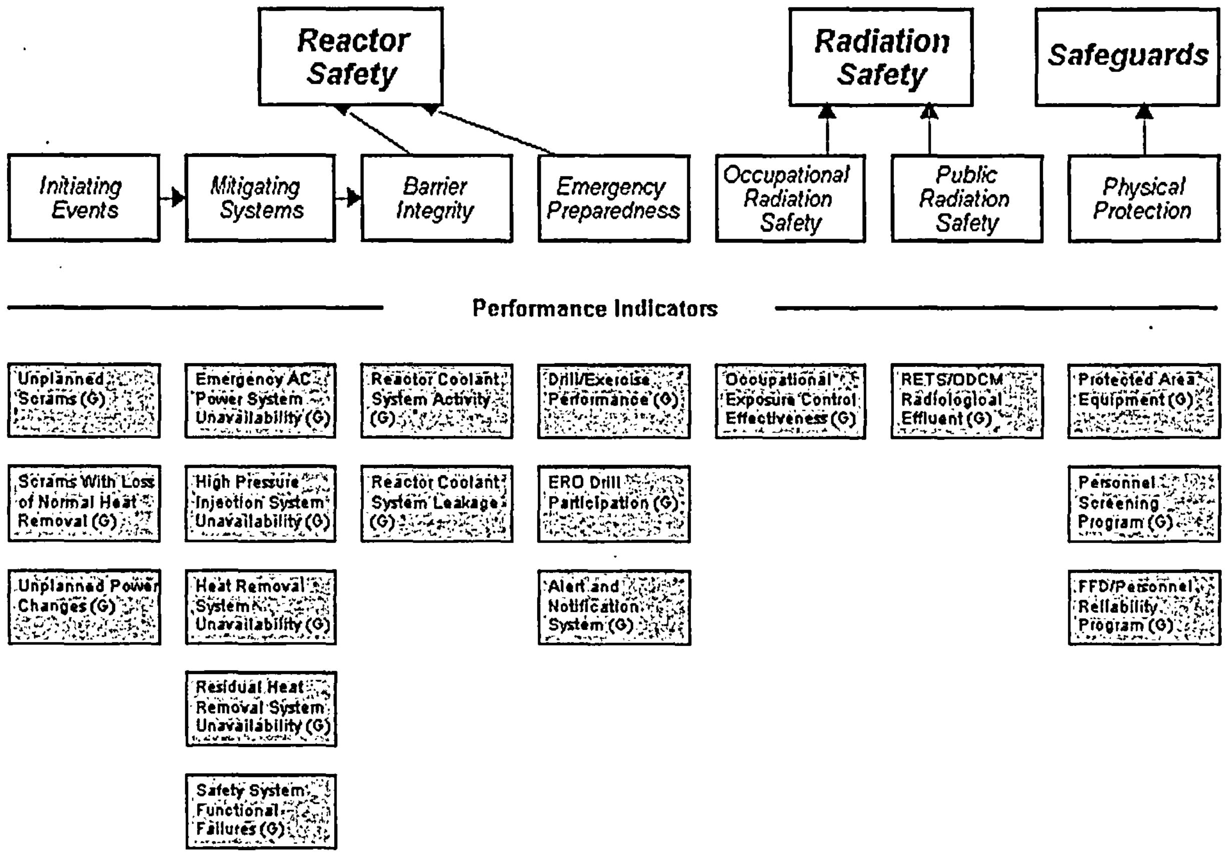
Third (Optional) Inspection

- Objective: To verify that the applicant has loaded future commitments into its commitment tracking system
- Scheduled for March 1, 2005

Farley, Unit 1, 3Q/2004 Performance Summary



Farley, Unit 2, 3Q/2004 Performance Summary



Section 3: Aging Management Review Results

- Summary: FNP LRA met 10 CFR 54 for AMPs and AMRs
  - 3.0.3, Aging Management Programs
  - 3.1, Reactor Vessel, Internals, and Reactor Coolant System
  - 3.2, Engineered Safety Features Systems
  - 3.3, Auxiliary Systems
  - 3.4, Steam and Power Conversion Systems
  - 3.5, Containments, Structures and Component Supports
  - 3.6, Electrical Components

GALL Review and Audits

- First pilot to fully utilize consistency with GALL audits for AMPs and AMRs
- Conducted on-site at SNC headquarters
- Staff review process described in SER Section 3.0.2
- GALL audit criteria
  - Consistency with GALL
  - No associated emerging issues or ISGs under development
  - Past precedents not used for FNP review

GALL Review and Audits (continued)

- Consisted of NRC staff and contractors
- Site-specific Audit Plan
- Aging Management Program Audit (Nov. 3-7, 2003)
  - Consistent with GALL, including with exceptions and enhancements
  - SER Section 3.0.3
- Aging Management Review Audit (Dec 15-19, 2003, and Feb. 14-16, 2004)
  - AMR line items that are consistent with GALL
  - Extensive in-house review prior to going on-site
  - SER Sections 3.1 to 3.6

Aging Management Programs (AMPs)

- Total 22 AMPs
  - 9 common AMPs
  - 13 component/structural group-specific AMPs
- Comprised of 8 existing, 5 enhanced, and 9 new AMPs
- GALL Consistency
  - Consistent with GALL: 8 (new AMPs: 2)
  - Consistent with GALL, with enhancements: 5
  - Consistent with GALL, with exceptions: 5 (new AMPs: 3)
  - Not consistent with GALL: 4 (new AMPs: 4)

Examples of AMPs with GALL Deviations

- Fatigue Monitoring Program (consistent)
- One-Time Inspection Program
- Non-EQ Cables in Instrumentation Circuits Program

Fatigue Monitoring Program

- New program will be consistent with GALL
- Specific components include:
  - PZR subcomponents
  - RPV shell and head
  - RPV inlet and outlet nozzles
  - RCL
  - Charging nozzles
  - SI nozzles
  - Class 1 piping ≥ 1 inch
  - Other Class 1 components
- FNP is currently using cycle counting method but will be modified to use fatigue monitoring software

Fatigue Monitoring Program (continued)

- Stress based on-line fatigue monitoring will be conducted for the surgeline and lower region of the pressurizer
- Evaluated effects of environmental impact on fatigue comparable to NUREG/CR-6260 locations
- Operating Experience: FNP Unit 2 piping to loop B cold leg

One-Time Inspection (OTI) Program

- New and plant-specific AMP
- Addressed by Commitment No. 10
- OTI program selects and inspects representative locations based on combinations of applicable materials/environment/aging effects
- OTI will be used for:
  - An aging effect that is not expected to occur
  - Validate the effectiveness of other credited AMPs
  - Aging is expected to progress very slowly

One-Time Inspection Program (continued)

- Specific components included in sample population:
  - Pressurizer CASS spray head
  - RCS small bore butt-welded piping
  - RCP thermal barrier CCW nozzle
  - Components exposed to environments of selective leaching
  - CVCS letdown and charging/SI pump mini-flow orifices
  - External surface of service water piping in EDG building
  - TDAFWP lube oil coolers (fouling of the tubes)
  - Condensate Storage Tank
  - Fuel Oil Storage Tanks and EDG Day Tanks

Non-EQ Cables Program

- A new program that will be consistent with GALL with an exception
- Exception: Non-EQ cables used in circuits with sensitive, high voltage, low-level signals are tested in accordance with the alternate XI.E2 program developed by the License Renewal Electrical Working Group (Commitment No. 12)
- Changes implemented by the applicant through the audit:
  - AMP revised to test all cables
  - AMP master document revised to include connectors

Reactor Vessel Surveillance Program

- Existing AMP, consistent with GALL with one exception
- Future action is addressed by Commitment No. 18
  - FNP plans to remove all surveillance capsules prior to entering PEO
  - The applicant committed that for each unit, alternative dosimetry will be installed to monitor neutron fluence
- License condition
  - Continue meeting ASTM E 185-82 standards
  - Require NRC staff review and approval for any changes to capsule withdrawal schedule and storage requirements

NiCrFe Component Assessment Program

- New and plant-specific AMP
- The program scope will include:
  - Nickel-based alloy RCS pressure boundary components
- FNP has committed via Commitment No. 11 to:
  - continue participating in industry initiatives
  - add implemented rankings and inspections consistent with latest EPRI-MRP recommendations
  - submit an inspection plan for NRC review and approval at least 24 months prior to period of extended operation (PEO)

Section 3.1, Reactor Vessel, Internals, and Reactor Coolant System

- Reactor Vessel, Internals, and Reactor Coolant System include:
  - Reactor Vessel
  - Reactor Vessel Internals
  - Reactor Coolant System and Connected Lines (includes Reactor Coolant Pumps and Pressurizer)
  - Steam Generators
- Staff concluded that aging effects associated with reactor systems will be adequately managed by the associated AMPs during PEO

Examples: AMR 3.1 RV, Internals, and RCS

- Loss of fracture toughness due to thermal aging
  – GALL: either enhanced volumetric examination or flaw tolerance evaluation be performed
- Leak before break (LBB) analyses cannot be taken as a substitute for the flaw tolerance evaluation
- The applicant committed to revise the LRA to be consistent with GALL

Examples: AMR 3.1 RV, Internals, and RCS (continued)

- Under crack initiation and growth due to cyclic loading or SCC
  - The staff approved FNP's RI-ISI program in March 2004
  - RI-ISI will be used for selection of small-bore Class 1, butt weld locations for the one-time volumetric examination, but will not be used to eliminate volumetric OTI
  - The applicant identified 2"x3" drain connection on normal letdown line for UT

Section 3.2, Engineered Safety Features Systems

- ESF Systems include:
  - Containment Spray System, Containment Isolation System, and Emergency Core Cooling System
- Aging Management Programs for ESF Systems
  - Water Chemistry Control Program
  - One-Time Inspection Program
  - External Surfaces Monitoring Program
  - Borated Water Leakage Assessment and Evaluation Program
- Staff concluded that aging effects associated with ESF systems will be adequately managed by associated AMPs for PEO

Section 3.3, Auxiliary Systems

- 23 plant-specific systems
  - 11 AMPs that manage aging effects related to auxiliary system components
- Staff concluded that aging effects associated with auxiliary systems will be adequately managed by associated AMPs during PEO

Section 3.4, Steam and Power Conversion Systems

- Steam and Power Conversion Systems (SPCS) include:
  - Main Steam System, Feedwater System, Steam Generator Blowdown System, Auxiliary Feedwater System, and Auxiliary Steam and Condensate Recovery System
- Aging Management Programs for SPCS
  - Water Chemistry Control Program
  - One-Time Inspection Program
  - Flow Accelerated Corrosion Program
  - Borated Water Leakage Assessment and Evaluation Program
  - External Surfaces Monitoring Program
  - Service Water Program
  - Periodic Surveillance and Preventive Maintenance Activities Program
- Staff concluded that aging effects associated with steam and power conversion systems will be adequately managed by the associated AMPs for PEO

Section 3.5, Containments, Structures and Component Supports

- Containments, Structures and Component Supports include:
  - PWR Concrete Containment, Auxiliary Building, Diesel Generator Building, Turbine Building, Utility/Piping Tunnels, Water Control Structures, Steel Tank Structures, Yard Structures, and Component Supports
- Aging Management Programs for Containment Systems
  - Inservice Inspection Program
  - Water Chemistry Control Program
  - Structural Monitoring Program
  - Fire Protection Program
  - Borated Water Leakage Assessment and Evaluation Program
  - Service Water Pond Dam Inspection Program
- Staff concluded that aging effects associated with containments, structures, and component supports will be adequately managed by the associated AMPs for PEO

Aging Management of In-Scope Inaccessible Concrete

	Aggressive Limit	FNP
pH	<5.5	6.7 – 7.1
Chlorides	>500 ppm	2.0 – 3.7 ppm
Sulfates	>1500 ppm	5.3 – 6.4 ppm

- Below grade environment is non-aggressive
- No history of aging degradation or failure of concrete components exposed to a below grade environment
- Phosphate (PO_4) level is 0.03 ppm, sampled from Service Water Pond
- Phosphate level is below detectable limit in groundwater sample near the main power block structure

Section 3.6, Electrical Components

- 10 component types subject to AMR
  - AMPs that will be used to manage aging effects
    - Non-EQ Cables Program
    - External Surfaces Monitoring Program
    - Buried Piping and Tank Inspection Program
  - Staff concluded that aging effects associated with electrical components will be adequately managed for PEO

Section 4: Time-Limited Aging Analyses (TLAAs)

- Summary: TLAAs met the requirements of 10 CFR Part 54
  - 4.1, Identification of TLAAs
  - 4.2, Reactor Vessel Neutron Embrittlement
  - 4.3, Metal Fatigue
  - 4.4, Environmental Qualification of Electrical Equipment
  - 4.5, Other Plant Specific TLAAs

Section 4.2, Reactor Vessel Neutron Embrittlement

- Five analyses affected by neutron irradiation embrittlement
  - Neutron Fluence
  - Upper-Shelf Energy
  - Pressurized Thermal Shock
  - Adjusted Reference Temperature
  - Pressure-Temperature (P-T) Limits

Neutron Fluence

- Conforms with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001

Reactor Vessel Upper Shelf Energy (USE)

Reactor Vessel USE	Acceptance Criteria (ft-lb)	FNP Unit 1 Staff Calculated Value (ft-lb)	FNP Unit 2 Staff Calculated Value (ft-lb)
Limiting Beltline Materials	≥ 50	53.1	57.9

- Based on ¼T neutron fluence values at the end of extended period of operation (i.e., 54 EFPYs)
- Applicant calculated USE values were 52.8 ft-lb for Unit 1, and 58 ft-lb for Unit 2
- Meets USE requirements of 10 CFR Part 50, Appendix G, for PEO

Pressurized Thermal Shock

Limiting Beltline Materials	RT_{PTS} Criterion (°F)	Staff Calculated RT_{PTS} (°F)
Lower Shell Plate B6919-1 (Unit 1)	≤ 270	195
Intermediate Shell Plate B7212-1 (Unit 2)	≤ 270	208.8

- Applicant calculated RT_{PTS} were 191 °F for Unit 1, and 208 °F for Unit 2
- Based on fluence values for the clad-to-base metal locations of the RVs
- Used latest reported surveillance capsule data for Units 1 and 2
- Meets requirements of 10 CFR 50.61 for PEO

Adjusted Reference Temperature (ART)

ART	FNP Unit 1 Staff Calculated RT_{NDT} (°F)	FNP Unit 1 Applicant Calculated RT_{NDT} (°F)	FNP Unit 2 Staff Calculated RT_{NDT} (°F)	FNP Unit 2 Applicant Calculated RT_{NDT} (°F)
1/4T	185.1	182	195.8	195
3/4T	161.2	159	162.9	163

- Most limiting materials and locations: Unit 1 - Lower Shell Plate B6919-1; Unit 2 - Intermediate Shell Plate B7212-1
- FNP calculation of the 1/4T and 3/4T ART conforms with recommended guidelines in RG 1.99, rev. 2, and is acceptable

Pressurizer-Temperature (P-T) Limits

- FNP 54-EFPY P-T limits for the PEO is based on an NRC-approved Pressure Temperature Limits Report (PTLR) process
- The applicant will generate P-T limits for the PEO in accordance with NRC-approved FNP PTLR

Section 4.3, Metal Fatigue

- Fatigue of ASME Class 1 Components
- Fatigue of Reactor Coolant Pump Flywheel
- Fatigue of ASME Non-Class 1 Components
- Containment Tendon Pre-Stress

Metal Fatigue (continued)

- Fatigue of ASME Class 1 Components
  - Evaluation of environmental effects indicated that two components may exceed the fatigue cumulative usage factor (CUF) of 1.0
    - Charging nozzle
    - RHR/SI nozzle to the RCS cold leg
  - The applicant committed to take corrective actions before the PEO (Commitment No. 14) via one or more of the four options it proposed

Metal Fatigue (continued)

- Fatigue of Reactor Coolant Pump Flywheel
  - Based on bounding analysis of 6000 start/stop cycles, and .08 inches of allowable crack growth
  - FNP RCP flywheels have sufficient margin against fracture for PEO
- Fatigue of ASME Non-Class 1 Components
  - Based on ASME Class 2 and 3, and ANSI B31.1
  - Most piping systems bounded by 7000 thermal cycles, sampling system designed for 22000 cycles, and this number of cycles would not be exceeded
  - Analyses of these systems remain valid for the PEO
  - Evaluation of EDG air start system found that the equivalent number of full-temperature cycles will be less than 7000 cycles

Containment Tendon Pre-Stress

- Applicant provided trending analysis
- Pre-stress forces projected for 40 and 60 years of operation

Tendon Type	Trend Line Value At 40 Years Kip/Tendon	Trend Line Value At 60 years Kip/Tendon	Minimum Required Value Kip/Tendon
Vertical	1215.5	1198.5	1157.7
Hoop	1156.0	1130.5	1021.7
Dome	1122.0	1088.0	1079.5

Section 4.4, Environmental Qualification (EQ) of Electrical Equipment

- Applicant's EQ Program consistent with GALL AMP, X.E1, "Environmental Qualification of Electrical Components"
- The staff concluded that applicant's continued implementation of EQ Program is adequate to manage electrical equipment

Section 4.5, Other Plant Specific TLAAs

- Ultimate Heat Sink Silting
- Leak-Before-Break (LBB) Analysis
- RHR Relief Valve Capacity Verification Calculations

Ultimate Heat Sink (UHS) Silting

- 1325 acre-feet for service water pond as the UHS was used in FSAR
- Average measured pond volume is 1418.5 acre-feet (12 sets of data over 22 years)
- Minimum recorded UHS pond volume is 1403 acre-feet (1984 surveillance data)
- Staff performed an independent regression analysis

Leak-Before-Break (LBB) Analysis

- Applicant reanalyzed the LBB analysis and projected the analysis through the expiration of the PEO.
- Applicant's reanalysis included evaluation of the impacts of pertinent aging degradation mechanisms on the crack growth and crack size acceptance criteria for the analysis.
- Staff concluded that the applicant's TLAA for LBB met the criterion of 10 CFR 54.21(c)(1)(ii) and was acceptable.

RHR Relief Valve Capacity Verification Calculations

- Applicant's future action is to update the analysis to include calculated 54 EFPY P-T limit curves before PEO (addressed in Commitment No. 15)

Conclusion

- FNP LRA has met the requirements of 10 CFR Part 54
  - Scoping and Screening
  - AMPs and AMRs
  - TLAA