Official Transcript of Proceedings ACRS-3347

NUCLEAR REGULATORY COMMISSION

Title: ACRS Plant License Renewal Subcommittee Meeting

Docket Number: (Not applicable for meetings)

Location: Rockville, Maryland

Date: Wednesday, April 5, 2006

Work Order No.: NRC-957 Pages 1-135

NEAL R. GROSS AND CO., INC.
Court Reporters and Transcribers
1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

TR04

DISCLAIMER

UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

April 5, 2006

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on April 5, 2006, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING

+ + + + +

WEDNESDAY,

APRIL 5, 2006

+ + + + +

The meeting was convened in Room O-1F16 of One White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m.

MEMBERS PRESENT:

JOHN D. SIEBER	ACRS Member (CHAIR)
J. SAM ARMIJO	ACRS Member
MARIO V. BONACA	ACRS Member
THOMAS S. KRESS	ACRS Member
OTTO L. MAYNARD	ACRS Member
WILLIAM J. SHACK	ACRS Member
GRAHAM B. WALLIS	ACRS Member

ACRS CONSULTANTS PRESENT:

JOHN J. BARTON	ACRS Consultant

ACRS STAFF PRESENT:

JOHN G. LAMB	ACRS Staff

NRC STAFF PRESENT:

HANS ASHER
KENNETH CHANG
JOHN FAIR
ROBERT HSU
MEENA KHANNA
P.T. KUO
TOMMY LE
JIM MEDOFF
MICHAEL MODES
DUC NGUYEN
JAKE ZIMMERMAN

CONSTELLATION ENERGY STAFF PRESENT:

DAVID DELLARIO	Constellation - NMP
MARK FLAHERTY	Constellation - NMP
GEORGE INCH	Constellation - NMP
PETE MAZZAFERRO	Constellation - NMP
ROBERT RANDALL	Constellation - Ginna
TIM O'CONNOR	Constellation - NMP

I-N-D-E-X

M-O-R-N-I-N-G S-E-S-S-I-O-N

8:31 a.m.

CHAIR SIEBER: On the record. I think we can get started now. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee and I'm Jack Sieber, Chairman of the Plant License Renewal Subcommittee for this meeting and this licensing action.

ACRS members in attendance are Dr. Graham Wallis, Dr. William Shack, Dr. Mario Bonaca, Mr. Otto Maynard, Sam Armijo and Dr. Thomas Kress. Also with us is Mr. John Barton, a consultant to the Committee and a former member.

The purpose of the meeting is to discuss the license renewal application for Nine Mile Point Units 1 and 2. We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, the Region I Office and the Constellation Energy Group. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed position and action as appropriate for deliberation by the full Committee. As part of the introduction, I should also mention that John Lamb is the Designated Federal Official for this meeting.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the *Federal Register* on March 21, 2006. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

A transcript of the meeting is being kept and will be made available as stated in the *Federal Register* notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting and I call on Jake Zimmerman of the Offices of Nuclear Reactor Regulation to begin.

MR. ZIMMERMAN: Thank you, Chairman Sieber and ACRS members. My name is Jake Zimmerman. I'm the Chief of the License Renewal Branch B in the Division of License Renewal in NRR. With us today is Dr. P.T. Kuo who is the Deputy Director of Division of License Renewal, also Dr. Ken Chang

who's the Chief of License Renewal Branch C who has primary responsibility for our audit and review activities of the Aging Management Programs.

The staff has conducted a detailed and thorough review of the Nine Mile Point Nuclear Station license renewal application which was submitted in May of 2004. Mr. Tommy Le, the Senior Project Manager for this review, will lead our presentation today on the staff's draft safety evaluation report. Mr. Michael Modes, the Region I Inspection Team Leader, will discuss his inspection related activities conducted at Nine Mile Point. In addition, we have several members of the NRR staff that are here to support the meeting and answer any questions that you may have.

During the review of the initial application, the staff identified issues associated with quality of information provided in the Applicant's resources that were available to support our review. As a result in March of 2005, the Applicant requested a 90-day grace period to address these issues. The Applicant will specifically go into more detail on how they addressed these issues during their presentation.

In July 2005, the Applicant submitted an

amended application. Based on the improved quality of the amended application subsequent responses to requests for additional information and the enhanced level of support provided to our audit and review activities, we were able to resume our review and complete it with the exception of two open items that we will be discussing today with you.

With that, I'd like to just turn it over to Mr. Tim O'Connor who is the Vice President for Nine Mile Point Nuclear Station to begin the Applicant's presentation. Thank you.

MR. O'CONNOR: Good morning. I am Tim O'Connor, Site Vice President at Nine Mile Point Unit 1 and Unit 2.

CHAIR SIEBER: Is your microphone turned on?

MR. O'CONNOR: Hello?

CHAIR SIEBER: Yes.

MR. O'CONNOR: Once again, I'm Tim O'Connor, Site Vice President at Nine Mile Unit 1 and Unit 2. I have responsibilities for the operations of the facility and the strategic direction of the facility for the corporation assigned to the site. I would like to introduce each one of the team members if I could.

MR. DELLARIO: My name is David Dellario, Director of Fleet License and Projects.

MR. MAZZFERRO: I'm Pete Mazzferro. I'm the Project Manager for License Renewal for Nine Mile Point.

MR. DELLARIO: And I'll go through the rest of them, Mark Flaherty sitting to Pete's left, the Acting Vice President of Constellation Energy Nuclear Technical Services. Our support team and subject matter experts we have here over to the right and behind me. Bob Randall, Director of Ginna Licensing, he spent the last 25 years at Nine Mile Point and just recently moved over to Ginna. Ray Dean, Director Quality and Performance Assessment. Mike Falin, Project Lead. Ken Haws, Project Lead. Dale Goodney, Design Engineering. George Inch, Design Engineering. Jeff Poehler, Corporate Engineering. And Carl Senska, Supervisor of Chemistry.

I would like to just briefly go over the agenda. It's similar format that you've seen before. We're going to start off with Tim O'Connor talking about or describing Nine Mile Point Nuclear Station and then talk about current performance of where the plant's at today. Then we're going to get

into the license renewal early recovery project and Mark Flaherty is going to discuss it from a corporate standpoint and Tim O'Connor will discuss it from the site standpoint. I'll go into the details of the recovery project. Then Pete is going to have a slide or two on the operating history, plant improvement initiatives, our license renewal programs, commitments, talk about implementation and then Tim will wrap it up with the summary.

Now I'd like to turn it over to Tim O'Connor to talk a little bit about Nine Mile Point.

MR. O'CONNOR: Good morning again. I'm Tim O'Connor. Nine Mile Point as you may know is owned by Constellation Energy, 100 percent for Unit 1 and approximately 82 percent for Unit 2. We do have a co-owner that has 18 percent ownership which is the Long Island Power Authority and is of Unit 2 only. The effective ownership of Constellation Energy for Nine Mile took place essentially on November 11, 2001.

The location of Nine Mile is in Lycoming, New York and the ultimate heat sink is the Ontario Lake and you know that Unit 2 does have a cooling tower. The supplier for the NSSS and the turbine for both units is General Electric.

CHAIR SIEBER: These units are separated in time from one another by quite of numbers of years and so the designs are quite different.

MR. O'CONNOR: Yes sir.

CHAIR SIEBER: And also the corrosion mechanisms and wear mechanism appear to be quite different also. Have these differences between the units affected your analysis in a significant way as far as developing aging management programs and scoping?

MR. MAZZFERRO: The materials and the environments at both plants are very similar and as you'll see going forward, our aging management programs, most of them, are common to both units. There are those two or three programs that are unit specific only because of what's in scope versus what's not in scope. But they are both boiling water reactors. The operating parameters are very similar. The materials of construction are similar.

CHAIR SIEBER: Okay. Well, we'll see as we go through your presentation.

MR. O'CONNOR: As you pointed out, the two units are different. I'm on Slide 5. There are differences between the two units, both in age and in the fundamental design. Unit 1 is a Mark I

containment. It's rated as 1850 megawatts thermal, 650 megawatts electric. It did go commercial 12/01/69. Its license expires on 8/22/09.

Unit 2 is a much newer unit, a BWR 5, a Mark II containment rated at 3467 megawatts of thermal, 1144 megawatts electric and it went commercial operation on March 11 1988.

MR. BARTON: Have you done any power uprates in the units?

MR. O'CONNOR: This was a power uprate a few years ago on Unit 1.

MR. BARTON: How much? What was the percentage of increase? Was it just the one percent that NRC gave you or was it something more?

MR. RANDALL: Robert Randall from Ginna. The Nine Mile 2 did a power uprate of 4.3 percent in 1995. Unit 1 originally started off and did a power uprate in 1972 I believe.

MR. BARTON: A long time ago.

MR. RANDALL: Yes. A long time ago. So there was the appendix. The Unit 2 more recent one was the Appendix K uprate.

MR. BARTON: Okay. Thank you.

MR. O'CONNOR: The next slide, Slide 6, is our current performance at both units. Both Nine

Mile 1 and Nine Mile 2 are green in the reactor oversight process indicators. There are no open inspections or findings with the status greater than green and Nine Mile 1 and 2 do remain in the Column 1 of ROP license of the column matrix. The units are running very strong.

MEMBER SHACK: Just looking at the PRA, it's dominated for both units apparently by Station Blackout. They don't share units. What's your backup diesel arrangement at the plants?

MR. O'CONNOR: I'm not sure I understood your question.

MEMBER SHACK: When I look at the PRA, the risk is dominated by Station Blackout accidents at both units. I was just wondering what the backup diesel arrangements were at each plant if you happen to know that.

MR. O'CONNOR: What you're looking for is how many diesels each plant has?

MEMBER SHACK: Yes.

MR. O'CONNOR: Both units do have backup diesels as you pointed out. Unit 1 has three diesels. Unit 2 has three diesels as well.

CHAIR SIEBER: Can you cross connect them?

MR. O'CONNOR: No, the units are separate.

CHAIR SIEBER: Is it on the same site?

MR. O'CONNOR: We have two separate distinct units, one right here and one right over there. (Indicating.) They were built apart in time and completely essentially independent although there are some cross-tie capabilities for fire protection.

CHAIR SIEBER: There are plants that are in similar circumstances as far as construction time is concerned and unit design and some folks try to reduce the risk by cross-connecting their vital buses. So that's a possibility.

MR. O'CONNOR: I'm not aware of any capability with that on either unit at this time.

CHAIR SIEBER: Okay.

MEMBER MAYNARD: A quick question. When did that construction start on the Unit 2? There was a commercial ops in '88, but do you know when construction started?

MR. O'CONNOR: I'm not.

MR. MAZZFERRO: It started in mid to late '70s. It was quite a long construction.

CHAIR SIEBER: Yes, they were 13 years

in the construction of the plant.

MEMBER BONACA: I imagine the ratings from the diesels are different for Unit 1 and Unit 2.

MR. O'CONNOR: The outputs?

MEMBER BONACA: Yes. I mean Unit 1 is a much smaller unit.

MR. O'CONNOR: Yes. I'm not sure of the exact -

MEMBER BONACA: But when you talk about three diesels per unit, is each one of them individually capable of supporting a division of ECCS.

MR. O'CONNOR: That is the intent, yes.

MEMBER BONACA: Okay. Thank you.

MR. O'CONNOR: That essentially concludes my openings. I would like to turn it over to Mark Flaherty who will cover about the License Renewal Recovery Project which was mentioned earlier and then I'll talk a little bit more about some of the site actions.

MR. FLAHERTY: Hi. I'm Mark Flaherty. I'm currently the Acting Vice President of Technical Services. Prior to that, I was the Licensing Manager for Constellation responsible for licensing

of all sites.

The license renewal application was originally submitted by Constellation in May of 2004. In March of 2005, both Constellation and the NRC agreed that there were quality concerns with the initial application. You can kind of bend these concerns really into two areas. The first and major one, the (a)(2) scoping effort was inadequate and the other major area is that the RA responses from Constellation to the staff were also inadequate. There were some errors and the timeliness of those responses. As a result of this, both NRC and Constellation agreed that a grace period was necessary to improve the application and that we would submit an amended application to facilitate NRC review.

In response to this, we did do a root cause analysis tied to the corrective action program. The root cause identified three major areas for the quality concerns. The first one dealt with isolationism, isolationism both within the project team itself and its interaction with the rest of the site and isolationism with respect to the rest of the industry and license renewal efforts, these various NEI working groups and that

type of thing and the team was not strongly interactive with those efforts.

MR. BARTON: You had a consultant at every license renewal meeting that I can remember with the staff and when I read that you submitted a sub par, that's my term for it, application. I just wonder about the quality of the whole organization because you were represented at every license renewal meeting that I've attended and I've been at quite a few of them. So I don't know how you screwed that up so to speak.

MR. FLAHERTY: Well, a lot of the isolationism was caused by the successes with the Calvert License Renewal process. Since we were the leader at that point in time, a lot of the project team members relied on that success and didn't recognize that things were changing, that the expectations had increased, that type of thing. So again, that was tied to while we may have been participating in some of the meetings and such, that information was not being actively fed back within the project team and utilized.

CHAIR SIEBER: When I read your description of your corrective actions and root cause determination it seemed to me that the issue

of isolationism applies not only to the license renewal process but to day-to-day operations and there are other plants that have marched down this path and ended up substandard in their operation and in the maintenance of their plant. I presume that you all have learned from this instance that you can't afford to have isolationism with this plant in any aspect of its operation or maintenance. Have you learned that?

MR. FLAHERTY: Very much so and I'll discuss in the next slide the response from corporate response solution and Tim will get into the site responses.

CHAIR SIEBER: Okay.

MR. FLAHERTY: The second item that we identified was management engagement. Again this is also tied to the original Calvert success with the project team which is that management viewed it that okay, this team has successfully done this effort for another facility within Constellation. So there was a limited management oversight of the project team both at the site and from corporate.

The last item that was identified was a lack of resources. Again, the team was isolated. It was a small team and their ability to respond

back to RAIs and given the initial quality application stretched a lot of the resources. So in response to these three items that were identified, on Slide 8 here, I'll discuss how we respond to it corporately and then Tim will respond specifically how the site also responded because it was a two-pronged approach.

First item which really dealt with management engagement was the project was turned over to Fleet Licensing. As my chief nuclear officer said, license renewal has the word "license" in it. So it belongs within licensing. Now this, I guess getting back to your question about lessons learned applying to elsewhere, this position that we created, this director overseeing licensing projects, oversees licensing's input into large projects such as power uprates, tech spec conversion efforts, license renewal application. So we're taking the lesson learned from license renewal and saying that if we have a large submittal that's going to the NRC that requires a lot of interaction with the NRC, we want a specific point of contact within Corporate that provides oversight for those projects and then feeds that information both back to the site and to Corporate management. So there's

a direct response, I guess, to your question about lessons learned.

We also implemented an extensive checks and balances and this deals with the isolationism root cause. This includes key performance indicators both to track already meetting the time line for submittal, are we resolving technical issues, that type of thing. So it makes it visible to everybody including management where we are with the status of the project.

Establishing challenge boards, basically a challenge board is where a technical issue or concern or part of the submittal is finalized. It goes before a review board with multiple parties involved including management to basically challenge the adequacy, the technical appropriateness, that type of thing, so it's not one person making any decision. It's a collective effort and this provides a mechanism to ensure that, yes, what we are submitting is correct and appropriate for the station.

We also implemented weekly management staff status meetings. This was either by conference call or face-to-face meetings where we review the KPIs, what issues were involved, that

type of thing. So everybody was aligned. So these meetings and phone calls were both with a site vice president and our corporate management. So it was again a two-pronged approach. And also --

MEMBER WALLIS: I'm just wondering if all this matters. I mean I hear this from students all the time, "I did all the right things." But what matters is the product. That's really what matters.

MR. FLAHERTY: Yes.

MEMBER WALLIS: Thank you.

MR. FLAHERTY: And so the final product for the amended application, I believe, did show that these efforts and corrective actions were appropriate and did result in a positive impact. In fact, we now have lots of licensees who do come to Nine Mile Point to see how the recovery effort actually accomplished or did things because in many respects, we've become the new reference point or model for various aspects of the application submittal.

We had also had periodic meetings, or I did, with the chief nuclear officer and President of the company, Mike Wallace who were extremely interested in the recovery effort, that type of

thing and again challenged both the project team and management to make sure that everyone was aligned and it was being done correctly. And finally, we added extensive resources to the project team. I believe, Dave, at the time we had 36.

MR. DELLARIO: Thirty-seven.

MR. FLAHERTY: Thirty-seven parties working on the project as part of the amended application.

MR. DELLARIO: And it did not include the nominal staff that was also supporting the project.

MR. FLAHERTY: So that was the corporate response and I'll turn it over to Tim for the site response.

MR. O'CONNOR: There were a lot of your questions earlier I understand them. This particular project we found ourselves in the position where the site essentially had delegated it to somebody else. So it had taken itself out of the accountability position that it owned and it was responsible for not only the actions but the results of them. And that gave us quite a bit of pause to how are we doing things across the board. If this could happen on this particular project, could it

happen other places?

We've changed our processes and our responsibilities and roles and accountabilities starting that with me. My job is to make sure that anything associated with the site, doesn't matter what it is, is my personal and site accountability. So we've established that set of processes rules and accountabilities so that we do not find ourselves in a position of delegating things out that belong to the site.

Another thing we've learned with projects is some of these projects go an extended period of time and from benchmarking with other facilities, the thing that one has to do is preestablish results that you're looking for the outcome to be in advance before you get started and then have intermediate milestones and metrics to validate that in fact those results are what you're going to accomplish. That is again system changes that we've made at our facility and have trained people so that can perform to those expectations.

Another item that we learned was that projects doesn't make any difference. If the site owns it, then it has to participate in it and not just in a side perspective. It has to participate

in an integral manner. So in our case with this, it's maintenance, operations, engineering and other organizations and personnel from the site, from the day-to-day operations have to participate and have to become part of that particular team which means that they're assigned responsibilities associated with these projects. We do that across the board regardless of what it is.

As Mark had said earlier, just because you have actions doesn't mean you're getting the results. So establishing and validating progress is one perspective that we do with all jobs, but the other is the challenge boards aren't just to assure we're doing what we said. Challenge boards are to review the project quality of whatever it is that we're doing. Do we have the outcome that we're looking for and how do we know that and what performance can we measure in order for us to establish that we're in fact on the right path?

Independent oversight is another element that we've strengthened. An independent oversight isn't just the corporation although it's one piece. It's also our quality assurance organization and subject matter experts. We've done more benchmarking and more focusing on bringing in

externals who have larger experiences than we do or the corporation to participate and give us I'll say the challenge of whether or not we are keeping the industry standards and expectations.

Finally, one of the other things that I think we've learned was that anything of this size, you need engagement. You need engagement from the entire site and the only way to do that is to communicate it and to encourage people to understand what's taking place, educate them and quite frankly what we find when we do that is we get more participation. Participation is what assures that we deliver what we expect.

MR. BARTON: And how do you do that? How do you accomplish that everybody on site knows what the goal is, where the organization is going? What's the mechanism you use to convey that?

MR. O'CONNOR: We have several -- In fact, we've actually established communications people now at our site. Their primary position is to help us provide information sources. So we do it by letters. We do it by face-to-face. We do it by group discussions. These are I'll say three or four different types of venues that we use and quite frankly we do cross sections after we've

communicated it. We do follow-ups to validate did the information get to the people that we expected.

So if I communicate something out, I'll do a survey shortly thereafter to go down to the lowest levels and find out what in fact penetrated. I find out sometimes it works and sometimes it doesn't which means I have to recommunicate or do other follow-up sessions to make sure that the information is provided. We find that to be pretty effective and as a result, we're getting more I would say understanding and engagement of our work force.

MR. BARTON: The communications people you referred to, do they report directly to you or do they report to somebody offsite in Corporate?

MR. O'CONNOR: The reporting relationship is a direct line offsite but a functional line to me on a day-to-day basis.

MR. BARTON: How often do you communicate with the Corporate. I assume it's a Corporate officer that's in charge of communications. How often do you have communication with that person?

MR. O'CONNOR: Several times a week and I meet with my communications person almost daily.

That's all I have to tell you about what we've learned from the site and how we're applying it across the board.

CHAIR SIEBER: Do you publish a plant newspaper or anything like that?

MR. O'CONNOR: Yes sir.

CHAIR SIEBER: Do you have all-hands meetings ever?

MR. O'CONNOR: Yes sir. In fact --

CHAIR SIEBER: How often?

MR. O'CONNOR: Good question. I have a once-a-month that I myself and several of my team, we provide performance updates from all perspectives on the facility whether it's day-to-day operations or whether it's things that are coming up aligned, milestones, performance at the site, every month and we do I would say get about 90 percent of the population of the site goes every single month. Depending on what shifts they're on, we have do some arrangements to cover for them. Then once a quarter, we do more of a global corporate type of performance update to the site. So they get an understanding of where the company is going as a whole.

MR. BARTON: Do the Corporate people

come down and participate in that one?

MR. O'CONNOR: Yes, they do.

CHAIR SIEBER: Okay. Go ahead.

MR. DELLARIO: Thank you, Tim. I'm now going into some of the project actions that we took during the recovery project and, Dr. Wallis, you mentioned it really doesn't matter unless you get the final product right. So when we jumped in the recovery project, the first thing we did is we spent a month defining the gaps, trying to understand what good looks like and what does the team need to look like going forward? Looking at our resources, do we have the right qualifications and as you heard from Mark and Tim, the site needs to get more involved.

So the first thing we did is we supplemented the project team with Nine Mile Point resources. At the time we were in the middle of outage when we started the recovery process. So I had to initially go out and get some contractors. I was focusing on contractors in two different areas and I say contractors. The ones we brought in for an example would be a retired SRO from Nine Mile Point that had been there 20 some years. So it may have been a contractor, but they knew the plant. So those are the individuals I brought in that knew the

plant.

I also needed to supplement the staff with contractors that worked on other license renewal projects that were very successful, so paint the picture of what does good look like. They have been involved with license renewal projects. They've been very successful and we wanted that knowledge and that fresh set of eyes going forward.

We also had to consolidate the team to Nine Mile Point. Initially, we had folks down in Crofton, Maryland doing some of this work. We moved the whole staff to one location.

We did extensive benchmarking, called other applicants, talked to them, asked them what they did, went through their application, compared it to ours, looked at RAIs. We brought in a senior license consultant and we did a lot of internal and external assessments and this is the checks and balances that Mark spoke about. Internally, we had an individual on my team that had worked in Q&PA for years.

Every week I would point to a different area of the project and say give me an assessment because every day I had meeting with my Lead and they would tell me right where we're at while I did

the checks and balances. You go and assess this area of the project to make sure that I have alignment from what I'm hearing because I was running the project at the time and what's going on in the project. In addition to that, we had what we called external assessments. Every two or three weeks, I would Q&PA Department onsite to come and do an assessment of the project. We also had an external assessment done through a consultant that worked directly for our chief nuclear officer. He would come down and assess the license renewal project and report directly back to the chief nuclear officer.

So as Mark mentioned, challenge boards, the extensive use of challenge boards. Challenge boards were able to take each one of our products. Each section of the application was presented in front of a challenge board and then we had Maintenance, we had Operations, someone from Chemistry, Training, just a large spectrum across the site to look at each section a different way. So that adds a lot of quality to the application.

It did another thing too. It educated the site about what is license renewal. So the team, the members on the challenge board, were

people that were supervisors, general supervisors and managers. So they were able to take it back to their groups and talk intelligent about what they'd seen in the last challenge board and what's going on or what's coming up because we also presented all of our program basis documents. We have 43 programs that are going to manage aging at Nine Mile Point. So each one of those were reviewed across the site and challenged in front of at this board. So what I'm describing right now is really the process that we used to ensure we had quality and we had ensured ourselves success going forward.

The next slide talks about what are the areas we focused on and as Mark had mentioned, one of the things that was identified to us was we had to redo the NSR scoping effort. We went back and completely did this over and I'm talking about reviewing the current licensing basis, went back through all the USARs.

We went ahead and we readdressed where's the safety-related NSR interface actually located out to that first seismic anchor. That involves the site. The structural engineering group got involved. The drafters marked it up on the drawings, went out to the field and put the hands-on

where that first seismic anchor was involved and the system engineers went out and marked it down. So you can see the site involvement. At times, we were using most of the structural engineers onsite which we had to defer some of the site activities to support the license renewal project.

The next thing we looked at was the spacial relationship between NSR, piping and safety-related piping. We brought people from Operations in to walk down room by room and identify the actual scope of where we were at. So you started out with the drawings, again mark them up and then go out in the field with licensed operators to walk all the piping down. That was an extensive effort.

We also had 28 outstanding RAIs, but we didn't go back and just answer those 28 RAIs. We went ahead and did benchmarking. We looked at the last six applicants plus the last two BWRs at that time which was Dresden and Quad Cities and reviewed 1600 RAIs. We wanted to make sure not only were we going to adequately and in a quality manner answer the 20 outstanding, but we wanted to make sure that we addressed any potential RAIs or other applicants had questions too that we should address before we get them from the NRC.

CHAIR SIEBER: You ended up with a large number of RAIs nonetheless. Right?

MR. DELLARIO: Yes.

CHAIR SIEBER: Three hundred and some. How many was it?

MR. DELLARIO: Three hundred and twenty-four.

CHAIR SIEBER: Okay. That's a lot.

MR. DELLARIO: Yes, most of those were before the amended application.

MR. BARTON: So most of those were what?

MR. DELLARIO: Prior to the amended application.

MR. BARTON: All right. Just an example that the initial application wasn't too good.

CHAIR SIEBER: Yes.

MR. DELLARIO: Another challenge though with the project at that time was after we submitted the application the project team, a lot of people, left. So when the NRC started challenging the application perhaps it wasn't at the level it should have been at, but we didn't have the people to answer the questions.

MR. BARTON: Were they in-house people or were they contractors?

MR. DELLARIO: In-house people.

MR. BARTON: They left for what? Left the company?

MR. DELLARIO: Yes. So we had to deal with a resource issue. That's when I talked about the recovery project and bringing the right resources back. That was the first thing we identified. We didn't have enough people on this project. So you could quickly build up your RAIs when you can't answer questions verbally and they officially send you an RAI and it just kept stacking up and the team couldn't keep up with them. So it was a domino effect.

The last part of our effort, the focus, was on aging management programs. We did a lot of extensive benchmarking to look at what is a program basis document. What are the characteristics of a good program basis document and we redid those. Now the individuals that developed our program basis documents and they are aligned to go Rev 1 are the site program people.

These aren't the project program engineers, but they are the site program people and I say that because they understand what's in the goal, our Nine Mile Point program owners. They

understand the commitments. So they have this body of knowledge going forward. So there's not going to be where the project goes away and then we have to turn it over to the site. They were heavily involved with development of these programs which we thought that was very important because they're going to own these after the project goes away and they need that body of knowledge.

So the results, we submitted the amended application. The letter went out on the 14th. We hand-delivered it on the 15th. We feel very comfortable that we addressed the NRC's quality concerns and I talked about checks and balances and I base that off of the successful audits we had in the fall and the inspection did very well. As I mentioned, the way we went through this recovery project in getting the site involved, it helped us accelerate the transfer of that license renewal knowledge prior to the ending of the project.

That's all I have. Now I'd like to turn it over to Pete Mazzferro to talk a little bit about the operating history.

MR. MAZZFERRO: Thank you. My name is Pete Mazzferro and again I'm the License Renewal Project Manager. What I want to talk today about is

a little bit of the history of the plants and some of the initiatives that we've implemented over the years that had to do with aging management as well as then some of the initiatives we have currently in place and going forward and then a talk about the commitments and our implementation plan to meet all those commitments.

Looking at the operating history for Nine Mile 1 and Unit 2 in previous years, we've replaced the recirculation piping at Unit 1 and that was because of an IGSCC concern. That was in the early 1980s. At Unit 1 and Unit 2, we have indications of cracking on our core shroud. For Unit 1, we've made repairs. For Unit 2, we're still in the inspection mode. I'll talk about those a little bit more.

CHAIR SIEBER: Could you describe the cracking from the standpoint of orientation and what the repair consisted of?

MR. MAZZFERRO: I have a couple slides.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: Just hold on a second and I'll get into those details.

CHAIR SIEBER: All right.

MR. MAZZFERRO: So Nine Mile Point 2

then is still just convention 304 stainless steel piping.

MEMBER SHACK: For?

MR. MAZZFERRO: The recirc piping.

MEMBER SHACK: Unit 2?

MR. MAZZFERRO: It's 316L.

CHAIR SIEBER: You have to speak into the microphone.

MR. INCH: My name is George Inch from Design Engineering. Unit 2 piping is 316 L.

MEMBER SHACK: So that was original construction, originally 316 L.

MR. INCH: Original. The Unit 1 piping was replaced with 316 nuclear grade.

MR. MAZZFERRO: Our isolation condensers at Unit 1 we've replaced the tubes in those in late 1997 because of a leak that we had. I have another slide on those to talk about that in some detail. We had some piping degradation on our reactor -- cooling system in the late '90s. We replaced that and we've had leakage in the past on our stub tubes for the CRD stub tubes. We've done a repair on that and I have more information on that as well.

With regard to the core shroud cracking on Unit 1, we identified cracking and in 1995, we

installed tie rods to basically tape the structural integrity of the horizontal welds. In 1999, we installed clamps to replace the --

MEMBER WALLIS: I understand you had 30 percent cracking. In the SER, it says core shroud welds H4, H5, H7 had greater than 30 percent cracking. It seems like a lot.

MR. INCH: This is George Inch. That's fairly typical of a BWR shroud. That's not unusual.

MEMBER WALLIS: Were they really growing at $2E^{-5}$ inches per hour? That's about one inch in five years. So how do they ever get to 30 percent cracked?

MR. INCH: We're talking about circumference, now in terms of percent of circumference cracking and the core shroud cracking is dominated by residual stress profiles from the original welding. Those profiles are such that as the cracking progresses through wall the stress intensity that drives the cracking significantly drops off. So the crack growth that's noted there is an average crack growth and it's consistent with what the industry's found.

MEMBER WALLIS: So it's a message that there were these big cracks, but they've essentially

stopped growing. So the fix has worked or there's nothing to worry about anymore because anything that's going to happen has happened. Is that essentially the message?

MR. INCH: Well, no. It's under control. It's understood and it's being managed with water chemistry, inspections, going forward.

MEMBER SHACK: But your tie rods are actually a full structural equivalent to the horizontal weld. Right?

MR. INCH: That's correct. At Unit 1, the tie rods replace the H1 through H7 welds.

MEMBER WALLIS: So if it were 270 degree cracking it would still be all right.

MR. INCH: That's correct.

MEMBER WALLIS: You could tell it by the tie rods.

MR. INCH: The tie rod assumes that those horizontal welds are 360 degree through-wall crack.

MEMBER WALLIS: So that to me is a separation, 360 degree through-wall crack. Isn't that a separation?

MR. INCH: Yes, there are very conservative assumptions associated with that

report.

MEMBER SHACK: What do these vertical weld clamps look like that patch up the vertical welds?

MR. INCH: Mike, there's a slide. It's a picture. What they are is the vertical welds at Nine Mile 1 that have cracking on them are in the belt line. They're 90 inches long and what we have is on each one of those welds, V-9 and V-10, we have two vertical weld clamps and that's an as-installed picture. It's a plate, an inch thick plate, that is pinned, it has two pins, that go through the shroud that have acentrics on them. So when they rotate, it tightens up into a hole, EDM-2 holes in the shroud, and each plate fits in that with those acentric pins and the assumption is that the vertical weld is flawed the whole length of the 90 inches and these plates will ensure that barrel section's integrity.

MEMBER SHACK: So it's a full structural replacement.

MR. INCH: Yes, it is.

MEMBER SHACK: And it only take two pins to do that?

MR. INCH: Well, it's two plates on each

weld and the pins are fairly substantial. They're 3.5 inch diameter pins and the plate is also substantial. It's an inch thick plate.

MEMBER SHACK: And the material for the pins and the plates?

MR. INCH: The material of the plate is an XM-19 material and the pins are, I believe, a stainless 316.

MR. MAZZFERRO: Okay. So that's basically the complete story for Unit 1 on core shroud cracking. For Unit 2, we've identified cracking back in 1998 and via an analysis, that was determined to be acceptable at that point. We did a reinspection in the year 2000 that was also satisfactory. In 2000/2001, we implemented dual metal chemical injection and hydrogen water chemistry. We did another inspection in 2004. That inspection was also satisfactory and we have another inspection that's scheduled for our outage in 2008.

MEMBER SHACK: Now on your inspections, I assume the shroud is reasonably accessible. For the core shroud support, are all the welds accessible for inspection?

MR. MAZZFERRO: You're referring to the welds at the bottom?

MEMBER SHACK: The welds at the bottom, yes. In fact, I guess I'm most interested in Nine Mile Point 1, the BWR-2.

MR. INCH: Yes. My name is George Inch. The Unit 1 has a conical support.

MEMBER SHACK: Right.

MR. INCH: And that's very accessible from the top surface. So we can get to 100 percent of that conical support while in the H9 welding we call it the support of the vessel weld from the top surface.

The bottom surface access is extremely limited. There's a baffle plate that you have to get behind. So visual inspection from the bottom side is extremely difficult and what we've done is we've inspected that with because we have good access from the ID we were able to deploy a crawling UT that was able to interrogate that support weld from the ID with a phased UA probe and we got approximately 80 percent coverage and it's the tie rods that got in the way of some of the locations.

And that phased UA UT was done in 2001 after another BWR-2 in Japan had some identified cracking that was discovered when they were replacing the shroud. It was visually identified as

being selective on the bottom side and with no cracking on the top side. So the UT was deployed in that year to determine whether or not we had a similar condition and the UT is primarily for circumferential detection, but it had some capability for axial. It was highly sensitive.

We identified some indications similar to that characterization. We had access to the vessel OD of that location at the five recirc nozzle locations and in 2003 and 2005, we did a vessel OD UT of those locations to confirm that there were no indications propagating anywhere near the vessel. So because of the UT, we had very good coverage of that location.

MEMBER SHACK: Thank you.

MR. MAZZFERRO: Okay. Moving on to Slide 16 and talk a little bit about the isolation condensers. The experience that we had at Nine Mile Point Unit 1 is that in 1997 we had identified leakage through our tubes. So we entered a plant shutdown and actually replaced the tubes. The cause of that cracking was stress cracking of the tubes based on thermal cycling. As it turns out, the water level on the tube side was fluctuating. So we went into a repair. We replaced all the tubes

themselves and we did that with better material than what we had in there previously.

MEMBER SHACK: You replaced all the tubes?

MR. MAZZFERRO: We replaced the tubes in all four condensers, yes, and to get access to the tubes, it's all a welded design, we had to cut all that out. At the time, we also looked for a new design such that we could get access to the tubes on a more frequent basis and there was just nothing available in the time frame that we needed it. So we stayed with our original design which was a totally welded design.

CHAIR SIEBER: So how do you determine where the leakage is, what the flaws are like and how do you detect it and what would you do for an in-service inspection to determine the integrity of these tubes in the future to get to them?

MR. MAZZFERRO: We have a number of -- What we had is a number of programs applicable to our emergency condensers and those are consistent with the guidance provided in the GALL except for the eddy current testing. We did have to take an exception to that particular PAR. Our justification for that was based on the fact that we understood

what caused the cracks in the first place, i.e. the thermal cycling. We fixed that and we eliminated that stressor.

What we had discovered was that again our water level on the tube side was fluctuating and therefore we were basically heating and cooling our tubes. So what we did was we installed what we call a keep fill system on that line such that the water level is always maintained above the tubes. So now we've eliminated the stressor which caused the cracking. That was one of the items we used for justification.

CHAIR SIEBER: So can we conclude that this will last 10,000 years?

MR. MAZZFERRO: Our analysis concluded we could last past the period of extended operation.

CHAIR SIEBER: But you have no way to measure it.

MR. MAZZFERRO: What we have identified is an in-service leak test, whereby while the plant is in operation basically it will isolate any makeup to the shell side. So if there was any leakage past the tube, we would then see it in the shell side water level. Now at that point, you have actually leakage which would then negate the pressure

boundary function, but we would be able to detect it early enough that we wouldn't lose our heat transfer function for the heat exchangers.

Now that's just a confirmation type test again, based on the new material that we put in, based on the elimination of the stressors, and we have continuous monitoring so we know where the water level is.

CHAIR SIEBER: The Code requires that you be able to predict whether you meet or are going to hit minimum wall sometime before the next inspection. Right? And you can't do that here.

MR. MAZZFERRO: We can't do that in this case.

CHAIR SIEBER: Yes. You can't comply to the Code.

MR. MAZZFERRO: Our Code of Construction is B31-1.

CHAIR SIEBER: Right. It still requires you to do in-service inspection.

MR. MAZZFERRO: Okay. Really what we had in place is what we can do, but we can't do that particular part.

CHAIR SIEBER: Yes.

MR. MAZZFERRO: But again, we have other

measures in place based on design and --

CHAIR SIEBER: Yes, but they aren't substitutes in my way of looking at it. You have something in place, but it's not as good as what the Code would require.

MR. MAZZFERRO: Okay.

CHAIR SIEBER: Go ahead.

MR. MAZZFERRO: The next item I would like to talk about is the stub tubes, the Nine Mile Point Unit 1 CRD stub tubes. We had identified leakage in the 1980s. At that time, we applied for and received approval to use the roll repair. That was in the form of a safety evaluation in March of 1987. That roll repair we have used on our stub tubes and it has been successful to-date.

We recognize that that is approved only for us. The industry has submitted that the same roll repair, different acceptance criteria, a zero-leakage acceptance criteria, that's undergoing review and approval through the ASME Code Committee currently. That appears to be on a track to be approved this year.

So from a license renewal aging management program going forward, what we've committed to is to follow the Code Committee for the

roll repair which would again have a zero leakage criteria and then should a stub tube that's been rolled leak again in the future which we haven't seen, but theoretically it's possible, so if that were to occur, we would implement a zero leakage repair and on the slide, we identify one of the three repairs that could be implemented. One is a weld repair consistent with the 58A which is endorsed by the NRC in a Reg Guide.

CHAIR SIEBER: That's very difficult to do though, is it not? I mean I've been under those vessels. It's pretty congested under there.

MR. MAZZFERRO: The design has been --

CHAIR SIEBER: A lot of airborne.

MR. MAZZFERRO: Right. The design has been reviewed and approved. There are activities in place to qualify the tooling as well as the personnel and to do a demonstration that it will work. That's an ongoing activity within the industry.

CHAIR SIEBER: I presume it would be some kind of machine weld. It's not a hand weld.

MR. MAZZFERRO: Correct. There's a variation of the welded repair that would be subject to NRC approval and then in the future, there could

be a mechanical or weld repair, but before we would use that, that would also need to be reviewed and approved by the NRC.

CHAIR SIEBER: And how many penetrations do you have under there?

MR. MAZZFERRO: We have a total of 129 and to-date 33 have been roll repaired.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: The next item I'd like to talk about is a little bit about the Mark I containment on Unit 1. What we have on your slide is a simplified picture of the containment for Nine Mile Point Unit 1 and really the items to talk about here are a couple.

One is there's a renewed concern about corrosion on the outside of our drywell shell and this is an industry initiative that's going on currently. The issue was first addressed in the late '80s in response to Generic Letter 8705. At that time, we had done extensive inspections of our design to determine that we had not had any water leakage that impacted the exterior surface of our drywell shell. And since that time, we have instrumentation in place and we do periodic inspections to look for evidence of leakage and we

have not found any indications of any leakage of water that would have impacted the outside of the shell.

CHAIR SIEBER: You found corrosion nonetheless. Right?

MR. MAZZFERRO: Not on the outside.

CHAIR SIEBER: Okay.

MEMBER WALLIS: How did you know there wasn't on the outside?

MR. MAZZFERRO: In 1987-1988 again in response to Generic Letter, we actually did remote visual exams.

MEMBER WALLIS: Do you inspect something around the outside?

MR. MAZZFERRO: What we did is we looked in two different areas. One of them is at the top where the refueling seal is. We were able to access that area and go 360 degrees around that area and saw no indications again of any water staining or any leakage that had occurred.

Then at the bottom, we have ten drain lines that are the sand cushion drain lines and we sent up again a remote visual up through each of the lines to verify the lines were not plugged which they were not. We were able to look at the

condition of the sand and that was very dry and dusty. In small areas, we were able to look at the actual exterior surface and we did not find again any indications of any leakage.

MEMBER WALLIS: What's so special about -- I'm sorry, John.

CHAIR SIEBER: Go ahead.

MEMBER WALLIS: What's special about 225 foot elevation where you found the corrosion?

MR. MAZZFERRO: That was on the inside.

MEMBER WALLIS: Yes, but what's special about that elevation?

MR. MAZZFERRO: What's special about that elevation is (1) it's not coated, it was never coated from original design and (2) at that location we have our drywell area coolers which is basically we take a section from the top surface discharged at the bottom and then that is cooled by close-up cooling. However, every refuel outage, we go in and we do cleaning on those area coolers.

So what we discovered was by performing our maintenance activities, we were actually wetting the surface more than we should have been. At the time, we did not protect the area, the drywell liner or the concrete with any material. We just sprayed

water. We now know that's a problem.

MR. BARTON: The inside of the liner is not coated in Nine Mile 1. There's no coating on the lines.

MR. MAZZFERRO: At that elevation, it is not. The upper elevation which if you look at the cylindrical part, that is coated, but the bottom portion is not coated.

MR. BARTON: The bottom portion, you mean above the concrete floor it's not coated.

MR. MAZZFERRO: Correct.

MR. BARTON: Why?

MR. MAZZFERRO: That was the original design. I don't --

MEMBER MAYNARD: In the area where you found the corrosion, what did you do after you found it? Did you clean them or leave it? Did you coat it? What did you do with the areas?

MR. MAZZFERRO: The area was identified during our 2003 outage. We did, as required by the IWE Code, a detailed visual inspection and that met the acceptance criteria there. However, we also, because of our corrective action program, did UT measurements at four of the most severe locations and determined based on those thicknesses that we

were well above design and we have a program in place to look at those same locations again in our next outage which is a year from now.

Based on those results, we'll have a quantified corrosion rate for those locations and based on that information, we will determine what else do we need to do going forward. That would be above and beyond the IWE requirements. And again, that will depend on as the corrosion rate caused us to get to minimum wall sometime during or at the end of the period of extended operation which we would not want it to be or is the corrosion rate such that we wouldn't reach minimum wall for 200 years? Again, those are two extreme cases. We have a graded approach of what actions we would take depending on what that corrosion rate is.

CHAIR SIEBER: But right now, you don't know what the corrosion rate is because you only have one set of measurements.

MR. MAZZFERRO: That's correct, but what we did at the time, we took the as-found thickness for the drywell shell at those locations and we applied the original assumed corrosion rate which was a lose of 1/16th of an inch over 40 years. Just applying that corrosion rate, we concluded that we

would not reach minimum wall for 45 years.

MEMBER WALLIS: Excuse me. One-sixteenth of an inch in four years?

MR. MAZZFERRO: Forty.

CHAIR SIEBER: Forty.

MEMBER WALLIS: Forty years.

MR. MAZZFERRO: That was the original.

MEMBER WALLIS: But if you had that and you've been operating for quite a while, there would be an awful lot of rust on the floor or somewhere.

MR. MAZZFERRO: Right. That's why we don't think that's what we were getting. We weren't getting that --

MEMBER WALLIS: Lots of vapor would show you that.

MR. MAZZFERRO: Yes, but again because we did not have a quantified value, we used what our design value was which again is another reason why we're going to take another SAT, determine what the corrosion rate is at that location and then take the appropriate actions going forward.

CHAIR SIEBER: Now this is an open item for you.

MR. MAZZFERRO: Correct.

CHAIR SIEBER: As far as license renewal

is concerned.

MR. MAZZFERRO: Right.

CHAIR SIEBER: The staff has suggested to you all one acceptable way to resolve the open item.

MR. MAZZFERRO: Yes.

CHAIR SIEBER: Do you agree with the staff or do you have your own way?

MR. MAZZFERRO: No, we --

CHAIR SIEBER: Obviously, you aren't going to get a renewed license with an open item.

MR. MAZZFERRO: That's correct.

CHAIR SIEBER: I promise that.

MR. MAZZFERRO: Yes. We went with the staff actually last Monday in a public meeting and that was a very productive meeting, good discussion. We followed up with that with a letter that we just sent in yesterday describing in detail what our actions are and that's currently under their review.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: But we do believe it does meet, it will meet, with staff approval, but again, we just submitted that yesterday.

CHAIR SIEBER: And you've actually had nine years since you first discovered the corrosion

to make sufficient measurements to determine at what rate the corrosion is occurring. Right? Found it in '87.

MR. MAZZFERRO: No, it's in 2003. On the inside, it's 2003.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: Yes. That's why our next outage really is --

CHAIR SIEBER: Yes, three years.

MEMBER ARMIJO: I have a quick question. What's the environment that's causing the corrosion and can you monitor that environment or control the environment to basically eliminate the problem?

MR. MAZZFERRO: The environment that caused it again was because of a maintenance activity that we were performing and --

CHAIR SIEBER: Turned water on it.

MR. MAZZFERRO: And that change to that maintenance activity is in our corrective action program and that will be implemented before the coming outage so that we don't continue to do that.

MEMBER ARMIJO: So if you eliminate the water you expect the corrosion rate to stop.

MR. MAZZFERRO: We would expect it to significantly decrease, but that's again why we're

going to continue with the monitoring so that we do know what is actually happening as opposed to relying on an analysis or a projection.

MEMBER WALLIS: Does this water vapor come up from the torus region into this region? The suppression pool is, the water vapor from the suppression --

MR. MAZZFERRO: No.

MEMBER WALLIS: This cannot come up.

MR. MAZZFERRO: Up from the torus water?

MEMBER WALLIS: Yes, come up through the down comers and everything. There's no --

MR. MAZZFERRO: During normal operation, both the drywell and the torus is anoded with nitrogen. The only kind there is --

MEMBER WALLIS: But there's a pool in the torus. Right?

MR. MAZZFERRO: That's correct.

MEMBER WALLIS: And so that nitrogen is saturated with water. So it's not the water.

CHAIR SIEBER: No.

MEMBER WALLIS: Maybe it's an oxygen from somewhere, but the water is there, the water vapor is there.

MR. MAZZFERRO: In the torus.

MEMBER WALLIS: But doesn't that come up into the drywell too?

MR. MAZZFERRO: We didn't conclude that that would be significant. Again, when we discovered it, we were actually splashing water on the shell. That was much more the significant contribution than water vapor coming up.

MEMBER WALLIS: Yes, you were splashing water on the shell.

MR. MAZZFERRO: Yes.

MEMBER WALLIS: But isn't the drywell, the drywell atmosphere isn't completely dry, is it? It does have water vapor in it.

MR. MAZZFERRO: There is --

CHAIR SIEBER: Oxygen.

MR. MAZZFERRO: Right.

MEMBER WALLIS: Yes, we were talking about water.

MR. MAZZFERRO: There is some humidity in during normal operation in drywell. That's correct.

MEMBER BONACA: But you don't think that it comes through the refueling seals.

MR. MAZZFERRO: I'm sorry. Could you repeat that?

MEMBER BONACA: You do not think that some of the water comes through the refueling seals.

MR. MAZZFERRO: No, actually on the next page, we have a picture of our refueling seal. This is a completely welded design that does have drain lines which are instrumented to let us know if there is something leaking there and then if any water were to leak past the refueling seal, it would be collected on what we call our shelf area which is concrete and that's sloped away from the drywell shell. It also has a drain line that's instrumented for leakage.

CHAIR SIEBER: Other than the ten drain lines at the bottom of the shelf or the torus, you don't really have a lot of information about wall thickness. Right?

MR. MAZZFERRO: On the drywell shell?

CHAIR SIEBER: Yes.

MR. MAZZFERRO: Other than the UT measurements we took because of the corrosion on the inside.

CHAIR SIEBER: Yes, but that was specific to --

MEMBER WALLIS: One location, right?

CHAIR SIEBER: Yes, where you saw the

corrosion.

MR. MAZZFERRO: Right.

CHAIR SIEBER: As opposed to in general in the drywell.

MR. MAZZFERRO: Correct.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: And again, that was based on the extensive work we did in the late '80s to determine whether we had any signs of any leakage of any water impacting the exterior surface and then our monitoring since then. Now if we were to discover water staining or water leakage, obviously that would go back into our corrective action program and we would have to do an evaluation of the impact on the exterior surface and then we would take whatever measures we needed to take to make sure we did have obviously sufficient thickness in our drywell shell.

CHAIR SIEBER: Okay. Now you said that the containment is not coated on the inside.

MR. MAZZFERRO: Portions of it. If you go back to the slide or slipping, there's a cylindrical part which we call the upper elevations. That is coated. The bottom portion which we call a cylindrical part is not.

MEMBER WALLIS: The spherical part is not coated.

MR. MAZZFERRO: Correct.

MEMBER WALLIS: The spherical part. I think you said cylindrical for both.

MR. MAZZFERRO: I'm sorry. The spherical part. Thank you.

CHAIR SIEBER: Now there is some discussion in the inspection reports about coating supplied in containment where you inspect and repair coatings. Could you --

MEMBER WALLIS: That's the next slide I think. Right?

CHAIR SIEBER: Yes.

MR. MAZZFERRO: Right. We do have as I mentioned coatings on the cylindrical portion of the Unit 1 drywell. We do have a program of containment coatings --

MEMBER WALLIS: I was very surprised by what I read in the SER about coatings. It said and maybe the problem is with the NEI guidance rather than with you, but it says "Coatings are monitored for blistering, cracking, peeling, loose rust and physical mechanical damage." And this is somehow supposed to "ensure that the amount of coating

detachment from a substrate during a LOCA is minimized." Now if your coating is blistering, cracking and peeling, it's about to fall off presumably.

The LOCA environment is far harsher than that and I have some personal experience around the hose and stuff of coatings that look fine but when hosed with sufficient pressure would come off. It seems to me extraordinary that just looking to see if they're blistering or peeling is good enough to tell whether or not they'll come off during a LOCA.

MR. MAZZFERRO: There are two items here. One is by following the ASME standard which is what we do you're looking for those things. So that's the monitoring piece. The other part of it is the potential impact on our suction strainers.

MEMBER WALLIS: Which we have -- I guess. Right?

MR. MAZZFERRO: Based on the design analysis that was done when we installed the strainers originally and based on the results that we find by our inspections, we then look at is there an adverse impact on our suction strainers.

MEMBER WALLIS: That concerned me too because it says again that you find some areas of

degraded coating and then you "repair or defer while maintaining the total amount of degraded coatings below the permitted amount." Well, if I went in there and I found coatings peeling off, I would say that this may be prejudices all the coating in a LOCA because a LOCA environment is far harsher than require they peel off a coating by touching it or it falls off by itself under gravity.

So if I found any areas where the coatings were peeling, I would suspect a whole coating and that doesn't seem to be the attitude at all. I don't think it's necessarily your problem. Maybe it's a problem for the NRC and NEI, but I was really surprised when I read it. What is your take on this situation?

MR. MAZZFERRO: Basically, we've been participating with the industry and NEI following the guidance that's been accepted and I understand there are ongoing conversations between the NRC staff and NEI and we are continuing to participate to find a resolution of it.

MEMBER WALLIS: But if you find coating, paint, peeling off your house in some areas and you take a garden hose and you apply it with some force to the whole house, the paint will come off in lots

of places other than the places where it's peeling because all the paint is ready to come off. And I just don't understand this attitude. The LOCA jet is a very powerful jet in the area where it's close to where it comes out of the high pressure system.

MR. MAZZFERRO: Right.

MEMBER WALLIS: It's a far harsher environment than if you just visually look for the peeling. So maybe this is something we need to take to the staff, not perhaps just to you.

CHAIR SIEBER: Yes. I think what Nine Mile Point is doing is not different than what the rest of the industry is doing.

MEMBER WALLIS: I would say it's usual to find areas of degraded coatings during refuel outages. That means to me that the whole coating issue needs to be examined.

CHAIR SIEBER: I presume that all or almost all of your coatings are qualified coatings. Is that correct?

MR. MAZZFERRO: Yes.

CHAIR SIEBER: Okay. Well, we're a little bit behind and we just have four more slides to go. So why don't we see if we can finish up.

MR. MAZZFERRO: Okay. The next thing if

just to present to you some plant improvement initiatives. We've already mentioned that at both stations we have implemented Noble Metal Chemical Addition and Hydrogen Water Chemistry. At Nine Mile Point Unit 2, we're in the process of completing a re-rack of the spent fuel pool racks and that's going from Boraflex to Borell (PH). We will be implementing corrosion inhibitors.

MEMBER WALLIS: Before I ask about this re-racking, how much have you gained by that? If you look at how much the fuel pool was originally designed for, how much have you gained by this re-racking?

MR. MAZZFERRO: For Unit 1, we gained because we completed the re-rack on Unit 1, and it's a ball park figure. I think we gained another 20 percent or so and Unit 2 I don't know the numbers of how much additional fuel we would be able to store.

MEMBER WALLIS: But if you go back, has this happened before you made other changes to the fuel pool to increase its capacity?

MR. MAZZFERRO: At Unit 1, we have. Again, when we went from Boraflex to Borell racks --

MEMBER WALLIS: When we go from the original, each time you gain a substantial amount.

MR. MAZZFERRO: We gain -- Yes, and that again goes through NRC review and approval because it's actually an amendment to our tech specs.

MEMBER MAYNARD: Will you maintain full core off-load capability?

MR. MAZZFERRO: Yes.

MEMBER MAYNARD: And you'll do that throughout the extended period also.

MR. MAZZFERRO: There are more measures we will need to take in the future.

MEMBER MAYNARD: But it's your intent to keep the ability for a full core off-load.

MR. MAZZFERRO: At this plant, yes.

MEMBER WALLIS: So how soon will you have to take those measures?

MR. MAZZFERRO: I don't know.

MEMBER BONACA: Do you have a dry storage unit in now?

MR. MAZZFERRO: We currently do not have dry storage.

MEMBER BONACA: So your pool must be pretty full.

MR. MAZZFERRO: Actually with the re-racking, we were able to go, I know we can go past the end of our current license which is in 2009.

Off the top of my head, I don't know what the date is, where we lose that capability.

MR. DELLARIO: I think it's within the first couple of years of the period they set up. Right?

MR. O'CONNOR: Yes. We have capital projects assigned in our 2006 to 2011 that has dry cast storage as part of our additional measures. We begin the funding of the project in 2008, 2009 and 2010 as determined.

MEMBER WALLIS: So you're asking for a license renewal without knowing how you're going to handle this additional amount of used fuel?

CHAIR SIEBER: Yes.

MEMBER WALLIS: So we just sort of trust you that you'll figure out how to do it?

CHAIR SIEBER: Well, you can't penalize these guys. It's an industry problem.

MEMBER BONACA: Well, if they don't, it will stop operation. So they have to.

MEMBER MAYNARD: Actually most plants didn't have full capability for their initial license period too, counting on the positive. So I think it's pretty common at this point without the ability to ship it to DOE to develop interim

measures.

MEMBER WALLIS: With all these -- they keep gaining a little back by re-racking Boraflex and so on.

MEMBER MAYNARD: And then you get to dry cast storage.

MEMBER WALLIS: Then you get to a point where that doesn't work anymore. You have to do something.

MEMBER MAYNARD: Like dry cast storage onsite.

CHAIR SIEBER: Yes, and these are all commonplace.

MEMBER MAYNARD: Yes.

MEMBER WALLIS: So you're just saying that it's not your problem. It's someone else's problem.

MR. BARTON: No, it's his problem.

CHAIR SIEBER: No, it's their problem.

MR. BARTON: It's this guy's problem. He said he's in charge of everything onsite. It's his problem. I wrote that down as soon as he said that.

MR. MAZZFERRO: I stick to that.

MEMBER WALLIS: It would be a little

more reassuring if you had a plan or something that you could lay out and say we know what we're doing.

MR. MAZZFERRO: As Tim indicated, we do have a plan in terms of the company that does set out milestones and goals, whatever else, for addressing the fuel storage issue. But the time line for that is building the dry storage capability going forward beginning in 2008.

MEMBER WALLIS: I'm just still thinking of this as the public response to all these license renewals. The newest fuel issue is a common problem for all these license renewals and somehow the public has to be reassured that it's under control.

MR. MAZZFERRO: The last item on that slide, the station service transformers and disconnect switches, that's there because those components, we have it for a recovery from an SBO.

With respect to our aging management program that we credited for license renewal, there are 43 programs, eight new ones for Nine Mile Point, and we did align them to the guidance provided in GALL, Rev 1.

With respect to our commitments, we made 54 commitments between the two stations. They are entered in our official tracking system which we

call the Nuclear Commitment Tracking System. Our priority for completing these activities is very high. They're regulatory commitments and within our priority system, regulatory commitments is second only to safety issues.

We have an implementation plan and schedule that currently involves completing the Unit 1 in the common activities by 2007. That would allow time for the staff to come in and do their post license inspection.

MEMBER WALLIS: Okay. Can we stop here? I mean you've told us all this administrative stuff and how you're managing everything and there's been almost no discussion of any technical issue except for this corrosion which seems to be very small in the drywell. Aren't there some technical issues like steam dryers where there's cracking and so on? Have you view this as unimportant?

MR. MAZZFERRO: Well, the steam dryers for us are in scope. We have been inspecting them during outages. We have found indications.

MEMBER WALLIS: There are cracks and all that.

MR. MAZZFERRO: We've had to do repairs on our dryers.

CHAIR SIEBER: Unit 1 is one of the early plants with box-type steam dryer.

MEMBER BONACA: Are you planning a power uprate? I'm sorry.

CHAIR SIEBER: Pardon?

MEMBER BONACA: No, I was asking. I didn't realize you hadn't finished. I was asking if they are planning a power uprate at any one of the two units.

MR. MAZZFERRO: On Unit 2, not on Unit 1.

MEMBER BONACA: Okay.

MEMBER WALLIS: But you might with other plants being successful. You might decide to go for Unit 1 too.

CHAIR SIEBER: Might.

MR. BARTON: Unit 1 is pretty well stretched, isn't it, unless you did some major equipment replacement?

MEMBER WALLIS: So the steam dryer is okay because you're managing it okay. Is that right? You're observing things and checking it.

MR. MAZZFERRO: And doing repairs when we need to.

MEMBER WALLIS: Repairs when you need

them. That's good enough. There are no other technical issues at all.

CHAIR SIEBER: We have two open items and we talked about one of them during this meeting.

MEMBER WALLIS: What's the other one?

CHAIR SIEBER: Which is containment corrosion.

MEMBER WALLIS: But there's a fluent.

CHAIR SIEBER: The other one is s fluence issue. Maybe you can describe what you're doing on that one and that's on Slide 24.

MEMBER WALLIS: And we're going to get to that.

CHAIR SIEBER: I'm trying to help them get there.

MEMBER WALLIS: Yes, I'm just a little concerned.

CHAIR SIEBER: If you want to, you can go to --

MEMBER WALLIS: Let's go back to my original question. You say we've been good boys. We've gone through all the motions and all that and everything's fine. But really what we're trying to probe for is are there some technical issues that we need to be concerned about and we haven't really had

much discussion about where might be technical issues, but there aren't and so on. We just have to trust the staff to have dug into it and found those.

MR. MAZZFERRO: Based on our discussions and the review by the staff, any technical issues that have come up, we believe we have come to resolution on all of those and they've asked us as you know a number of questions.

MEMBER WALLIS: This is a bit circular because the staff writes in their report that the licensee did this analysis and claims that so on and so on and so on.

MR. MAZZFERRO: Some of the technical issues, we did talk about with respect to this CDR stub tubes, with respect to the core shroud cracking. Those are items that we obviously have to manage going forward and we will manage going forward.

As far as from an open issue standpoint, the SER includes two of them. We believe we've provided sufficient information for the staff to close both of them. The other open issue has to do with a fluence calculation or our original analysis for one of the TLAs. Portions of that analysis, the methodology had not previously been approved,

reviewed and approved, by the NRC staff. We submitted in the last couple of weeks a new analysis.

CHAIR SIEBER: Using what code?

MR. MAZZFERRO: Using the methodology approved by -- Do you want to help out, George?

MR. INCH: Yes, it was done using the DORT Code. It's an industry code, the Discrete Ordinance methodology. It's been reviewed and accepted for Nine Mile for meeting Reg Guide 1.190.

CHAIR SIEBER: Okay.

MR. MAZZFERRO: We'll jump to the last slide and conclude.

MR. O'CONNOR: We certainly have appreciated the time to talk to you this morning. I think you've heard enough about our lessons learned from the project itself and what we've gained from it. Unless there are other questions on the open items, at least you've heard what we believe to be the items to resolve which we think we've given the NRC the information they are looking for and find that it should be acceptable.

We do believe that we understand the issues and that our programs are sound for us to manage the aging issues. We do have these

commitments that we're making inside of our tracking systems. We do have accountability for that to make sure that nothing is missed. Our corrective action program is healthy and that is one of the vehicles that we use to make sure that we don't miss things.

And I can assure you that as I sit in front of you here is that we're going to operate the place effectively. We're not going to be behind the industry and we're going to continue to make sure that we reach the standards of excellence that are out there. And that's our commitment. We appreciate the time here for us to talk with you this morning.

MR. BARTON: Jack, before you hit the gavel, I have a question. I noted in this application there were some strange systems in scope that I hadn't seen before and maybe the Applicant can answer this. On Nine Mile Point on Nine Mile 1, you say that the city water system is in scope and loss of city water could prevent completion of a safety review function. What function is it and if city water gets lost which is not inconceivable, what's your backup?

MR. MAZZFERRO: City water is in scope for the A2 criteria of nonsafety related piping that

runs in the vicinity of safety related equipment. Therefore if there was leakage out of the city water system it could impact a piece of the safety related equipment. It's not the system function itself. It's one of these interactions.

MR. BARTON: It's one of these within proximity space issue.

MR. MAZZFERRO: Yes.

MR. BARTON: All right. Thank you.

CHAIR SIEBER: Okay. Any other questions? What I'd like to do now before we hear the staff's presentation is to take a break and it's pretty close to 10:00 a.m. So let's be back at 10:15 p.m. Off the record.

(Whereupon, the foregoing matter went off the record at 9:57 a.m. and went back on the record at 10:15 a.m.)

CHAIR SIEBER: On the record. We have a Planning and Procedures meeting that will begin shortly and we will lose two of our members so that they can attend that meeting. I'm not one of them. So I will stay here.

What I'd like to do now is introduce NRR and have them make their presentation and to do that we'll begin with Jake Zimmerman.

MR. ZIMMERMAN: I'm going to turn it right over to Tommy Lee, our Senior Project Manager responsible for the Nine Mile Point review.

CHAIR SIEBER: Okay. Good morning.

MR. LE: Good morning, Chairman Sieber. How are you?

CHAIR SIEBER: I'm fine.

MR. LE: Good morning, Members of the Subcommittee. My name is Tommy Le. I'm the Senior Project Manager in the Division of License Renewal. I have been on the task since July of 2004. The application was submitted in May.

Again, I would like to represent that staff to brief the Subcommittee today and the SER that we respectfully submitted to you on March 3rd is the result of all the hard work by all of the NRC staff behind me. My job was just to put it together. So I don't take credit for it.

CHAIR SIEBER: I think you did a good job of putting it together.

MR. LE: Thank you. It's heavy. Again, that also is a result from the patience and hard work from the Applicant's staff to provide the NRC staff with a resolution and all the things that the staff had wanted and so with that note, I also would

like to introduce to you with me I have Robert Hsu who is the Assistant Team Leader for the audit.

CHAIR SIEBER: Good morning.

MR. LE: And the Team Leader was Dr. Ken Chang. He got promoted. So he didn't want to be with the staff.

MEMBER WALLIS: I would like to say that these audits are very useful to us and in fact, we got an SER. We also got a very substantial audit report.

MR. LE: And with me is Michael Modes, the Team Leader, for the Region I team inspection. He supported the NRC review of the license review of the Nine Mile Point.

With that, I would like to have Slide 1 please. In this slide, I would like to brief the ACRS the same process that the staff has rigorously taken to review the application from Constellation Energy. First, I will go through the overview of how the staff had taken in the past two years and then we will discuss the scoping and screening review process and then we would ask Mike Modes to come in and talk about his inspection at Nine Mile Point and then in Section 3, we will report to the Subcommittee the aging management review results

that the staff had conducted and Section 4 is a TLAA. With that, Slide 3 please.

As the Applicant had previously reported, the application was submitted on May 26, 2004 requesting a 20 year license extension for both Unit 1 and Unit 2 at Nine Mile Point Nuclear Station. Unit 1 as you know is a Mark I, GE BWR-2. It has 1,850 megawatt thermal with 650 megawatt electrical. The operating license for Unit 1 expires on August 22, 2009.

For Unit 2, it's a Mark II, GE BWR-5 with a thermal rating of 3467 megawatt thermal with an electrical output of 1,144 megawatt with 4.3 percent power uprate as the Applicant had indicated previously. For the Unit 2 to be accepted for the review, the Applicant had requested for the scheduler exemption because the operating experience for that Unit 2 had not reached 20 years as required.

MEMBER WALLIS: I noticed that this is the first application for a BWR-2 and a BWR-5 for license renewal.

MR. LE: Yes sir.

MEMBER WALLIS: So you are setting a precedent here.

MR. LE: Thank you. The staff is reviewing it.

MEMBER WALLIS: So it's important that it be done right so the subsequent ones can follow the example.

MR. LE: We know we did it right. We did it carefully. The Nine Mile Point Station is located around six miles north of Oswego and I mention Oswego because that's the only place we can fly a plane to stay during our audit.

MEMBER WALLIS: That's where it snows a lot in the winter.

MR. LE: And snow. Mike knows about that.

CHAIR SIEBER: I've been there in January. It's miserable.

MR. LE: Yes. Michael was on one inspection and he had turned back. For those that have better, Syracuse is about 40 miles south, southeast of the plant. Slide No. 4 please.

The overview report here is the SER that we've presented to the members of the ACRS which was issued on March 3rd and we had 54 commitments by the Applicant. This was an increased number from 31 original commitments which was submitted in the

original application. The Unit 1 had 14 commitments. Unit 2 had 13 commitments. Those are plant specific. And the common are 27 commitments for both Units 1 and 2.

These commitments are going to be implemented two years prior to the period of extended operation as you heard the Applicant had stated. For Unit 1, it would be two years before that and the expiration is 2009. So I'm sure they are pretty busy like bee during the implementation.

The SER had two open items and no confirmatory item and for the two open items I would like to respectfully defer it to Section 3 and Section 4. The SER had three license conditions, the standard conditions. It had to do with FSAR supplement required by 54(d) and the activity that Applicant had to implement in accordance with Appendix A in the SER and No. 3 is the implementation of the most recent staff approved of the ISP program to demonstrate that they are in compliance with Part 50 Appendix H. Slide 5 please.

CHAIR SIEBER: On the last slide with the commitments, a lot of those have to be done next year.

MR. LE: Yes sir. That's why I

mentioned them.

CHAIR SIEBER: There's not a lot of time.

MR. LE: Yes. That's why they're not taking a vacation from now on. Slide 5, the NRR scoping and screening method, the audit was conducted on September 27 to October 10 of 2004 and this was conducted by the staff from the formerly Division of -- and for Section 2.1, the staff audited and identified an issue and that has been resolved through REI and the Applicant has provided additional information in the amended application.

During the scoping and screening methodology, the Applicant realized that the (a)(2) methodology was not within the acceptability of the staff requirements. So they did revamp and they had requested a 90 day grace period to address that and I will talk about that later on and also during the scoping and screening methodology the staff identified that there are insulation that is used as the fire wrap-around and structural steel fire protection and that has been added to the scope. Slide 6 please.

MR. BARTON: Wait a minute. You made a statement that the methodology for determining

compliance with 5054(a) appears to be rigorous enough to identify all systems. What do you mean rigorous enough?

MR. MODES: I think I made that statement.

MR. BARTON: What does "enough" mean? It could have been better. It could have been more.

MR. MODES: What you're reading is a report based on an inspection that is only a small slice of the total number of systems available for review.

MR. BARTON: Right.

MR. MODES: And the inspection process, really its goal is to arrive at a conclusion of reasonable assurance. It's one of the few areas where an inspector is given that latitude. So that is very carefully phrased wording to mean "hey, we looked at a slice. We looked at quite a few and what we arrived at is a reasonable assurance conclusion based on that. So what we think is that the methodology applied would continue to be applied elsewhere and it would arrive at that conclusion."

MR. BARTON: Yes, it came out of the inspection report on March 2nd.

MR. MODES: Right, and it's to indicate

that we can't possibly look at them all.

MR. BARTON: I got you.

MR. MODES: Okay.

MR. BARTON: Yes.

MR. LE: Thank you, Mike. On Slide 6, the staff would like to report to the Committee Section 2.2 -- level scoping and other REI questions that result in the following item: 14 new systems were added. Three previously included in the regional system. Application was removed. A new and revised license LR drawing and now identify the (a)(2) component was provided. The amended application clearly identified SSC within the scope of license renewal subject to AMR. The amended application now uses the standard component type and component intended function as consistent with the standard review plan by the staff and the industry NEI-95-10 to identify the SSC in scope and those that(* are the subject to ARM. Again, all issues were resolved in the amended LRA, this including the question from the audit staff and the REI from the technical staff in NRR and these are pursuant to 10 CFR 54.4 (a)(1) and (a)(2). Slide 7.

MEMBER BONACA: These 14 new systems added, they were added by the Applicant, all of

them.

MR. LE: Could you say that again?

MEMBER BONACA: Those 14 new systems which were added to the scope, were they identified by the Applicant? That's my understanding from the presentation.

MR. LE: Yes. During the 90 day review.

MEMBER BONACA: Yes. I understand. I'm asking did the staff identify any new system that should be placed that the Applicant failed to identify?

MR. LE: The staff won out that the original scoping from the Applicant were not addressing the regulations.

MEMBER BONACA: No, I understand that.

MR. LE: They went back and found more systems.

MEMBER BONACA: But once this is done, once they found the new systems and made these changes, you did not identify anything they had missed.

MR. LE: Yes.

MEMBER BONACA: All right. Thank you.

CHAIR SIEBER: I got the impression that the biggest issue there was the failure to initially

include non-safety related systems. Is that correct? That's what I got.

MR. LE: I think the staff originally, Greg Galletti was the team leader, and he identified that the ways that methodology of the (a)(2) were not rigorous enough.

CHAIR SIEBER: Okay.

MR. LE: So the Applicant in their presentation, they did a walkdown of every room and picked out all of the systems that might affect the SR component system.

CHAIR SIEBER: After marking up the drawings, they did a physical walkdown.

DR. CHANG: This is Ken Chang representing the Auditing. For all these 14 new systems identified according to the scope, the auditing review team had an audit onsite and we also did not find anything new that needed to be added to it.

CHAIR SIEBER: Okay. Thank you.

MR. LE: Slide 7 please. The staff would like to report to the Subcommittee the continuation of the scoping. In 2.3 Mechanical system, we had 45 total systems within the scope and subject to AMR, 35 of these systems BOP, 26 of them

auxiliary system and 7 are steam and power conversion for Unit 1. For Unit 2, there are a total of 61 mechanism systems. Forty-seven are BOP with 47 auxiliary systems and 7 steam conversion.

Section 2.4, Structure and Component Support, for Nine Mile 1, we identified the primary containment structure of the Class 1 and in scope, 11 structure, containment electrical penetration and -- I'm sorry. I'm on Structure and 11 structure commodity. For Unit 2, the same finding except that we have two -- system for structure and scope.

Section 2.5, Electrical and IC System and Commodity for Unit 1, we found that the cable and connections are nonsegregated in switchyard bus and containment and electrical penetration in switchyard component are the same for both units and they are included in the scope of license renewal. Slide 8 please.

As a summary of the scoping and screening effort done by the audit team and the staff review, we found that the Applicant's scoping methodology meets the requirement of 10 CFR Part 54 and the scoping and screening result including all SSC within the scope of license renewal and subject to AMR.

Now I would like to invite Michael to address the Region activity in the inspection.

MR. MODES: Gentlemen, good morning. Michael Modes, NRC Region I, Senior Reactor Engineer Team Lead for License Renewal. It's always a pleasure trying to survive a visit to the lion's den. And yes, it does snow in Oswego. My first trip up there to do the license renewal, we call it bag man. It has nothing to do with what the Mafia does of course. It's a previsit and I actually got thrown off the interstate and told to go somewhere else. So, yes, it does snow.

The inspection, this inspection, is the more efficient inspection than prior. It focuses on 10 CFR 54.4(a)(2) for nonsafety affects safety and I like to say this is a bottom up inspection. We start with the procedures and what's actually going on at the plant and we try to meet the aging management audit in the middle. It's like doing a tunnel from both ends. Hopefully we meet.

We conducted the inspection on February 14, the week of, and February 28, in addition to which I asked a very seasoned ISI inspector to do a containment walkdown during their subsequent outage on April 4th and because of the way the inspection

turned out, we walked away with 15 open items, five programs that we could not arrive at reasonable conclusion and subsequently we returned to go through all of those and found them to be satisfactory. They did quite a turnaround in the 90-day implement. Next slide.

It was quite a turnaround from what we had seen prior to that. What we really got a sense for in the inspection was there was a real lack of connection between the application, the programs and what the program people, the application people, had been doing and what was really going on at the plant. There was confusion, lack of ownership and a lack of connection in some places where proposed programs didn't even connect up. They weren't even in a form that could be reviewed. You can't arrive at reasonable conclusion if you don't know what they're doing.

So we conducted that follow-up inspection on December 12th. We reviewed all of the 15 items previously. I brought a very seasoned inspector with me as well on that inspection and asked him to spend that week going through the 54.4(a)(2) process with them. Where prior, a two-day walkdown in the initial inspection turned up

about four or five systems that we identified that weren't in, this time he wasn't able to identify any systems that hadn't been included.

So the inspection concluded that the open items were satisfactorily resolved and we closed them out in an inspection report. I might add that this will be the second plant in Region I to enter into the extended period and we are currently already planning both staffing allocation and scheduling for the follow-on inspection of 003, something we have to anticipate because we have to go through these pre-extended period outage inspections with them. That's a pretty big undertaking, almost equal in size. Any questions?

The following, the next two slides are all green. I've already told you that. Any questions? It's a pleasure, gentlemen. Thank you.

MR. LE: Thank you, Mike. Now we'd like to brief the Subcommittee on Section 3.0 which is aging management review results. Helping me in this presentation would be my Mr. Robert Hsu back there and Dr. Ken Chang. Oh, you're joining us again, huh? To brief the committee, we reviewed the usual 3.1 reactor vessel internal reactor cooling system, 3.2 engineering safety fissure system, 3.3 auxiliary

system, 3.4 steam and power conversion system, 3.5 containment structure and component support and 3.6 the electrical and IC component. Next slide.

The staff reviewed the AMR and AMP responsible by two groups, the staff from the Technical Branch in the NRR, namely the Division of Engineering and Division of Component Integrity, review of those plant specific AMR and AMP and the Audit Team headed by Dr. Ken Chang to perform the onsite audit for those items that the Applicant reported in the application that it's consistent with the GALL report and accompanied AMR line item.

In short, the DE staff did have about seven plant specific AMR in all the line items. The Audit Team conducted within two phases. As you're aware from the Applicant's presentation, the original application was amended by a new application and the Audit Team had conducted the original inspection during the weeks of August 5th, August 13th, October 21st and October 25th.

As you noted, there are more inspections, audits, than normal a license renewal plan would and, Dr. Chang, would you like to address some findings on that?

DR. CHANG: Ken Chang, Audit Team

Leader. In the review and audit of the original application, we followed a normal trial of going first time to do the AMP audit and that time it was two weeks because of the ACRS probably knows that's Unit 1 and Unit 2 separate by time and also systems are very different. So essentially we are reviewing two plants.

We're not reviewing one plant. We reviewed and audited two plants. We structured the audit report in two sections, Unit 1, a common portion and Units 1 and 2. So it's a very detailed review. Through those reviews, the bulk of the review was done in the first two audits, the August 5th through 13th and August 13th through 17th.

What followed that is the AMR reviews. The structure of the Nine Mile Point License Renewal Application Team was the AMPs are handled by the plant staff and always at the plant and it was headed by Pete. And the AMRs were done by the Constellation Nuclear Services which is located in Crofton. Those are, you heard before, not well communicated and it's kind of, may I use the same word, isolated, isolation. So when we reviewed the AMRs, we reviewed at Crofton instead of at the plant. We reviewed at Crofton and even more so is

we always take any opportunity that we get together with the applicant to say "Well, let's do a little more review." We even do it in our contractor's office.

Actually, the first part of the review and audit was done in five trips, five meetings. At the end of the fifth meeting, we came to a point that Applicant has to commit to do a lot of modifications, supplements, to the extent that we think it's not feasible to accomplish in a short period of time. So we mutually come to an agreement that it's best handled by taking a gracing period.

So you take a chunk of time to address all the questions, all the problems, we identified in one shot and submit it in so-called amended or updated or whatever you like to call it application. So we will re-review the amended application or the updated application in another AMR. So the first period, the first phase, of the review and audit ends right there after we agree to take a 90 day gracing period.

July 14th, they submitted the amended application. Within less than two months, like in six weeks, we went there to do the AMP audit of the amended application and then within a month, we go

back there again to do the AMR audit. The amended application is in a much better quality and we talk about quality there.

Also we were amazed by the level of resource support for the Audit Team. We formed a big team there because there was a lot of review there. It was supported by the plant staff and by their consultants. You heard earlier that the team supporting the amended application they said about 37. I added it. It's 38. But then you take away the six challenge board members. So it's really 32, 32 people supported the amended application and also supported the audit of the amended application compared to the original one.

Now we have a big room full of people only in the entrance meeting. After that, people kind of went away. We don't get the kind of support we anticipated and we outnumbered the Applicant's staff. But in the second phase audit, they outnumbered us. In every breakout meeting, we only have two or three people. They have eight or nine. So we really have to run fast to catch up with them of which I'm glad because we are not there to have a good time. We are there to look at what you've done. Tell me what you've done in writing or

across-the-table discussions. So we were very happy with that.

And therefore after the two audits -- I'm sorry. Come back. After the first audit, we hammered all the AMP/AMR questions which is different from the original application down to five open items. Those five open items are a little tougher and are the focus of the second audit. The second audit was in October. That is amazing because normally we don't quickly come down to that small number of open items. Naturally, it was helped by the original audit. Some of them don't change.

We even extended the resolution of the audit findings to the exit meeting. The exit meeting which is probably in November.

MR. LE: Yes.

DR. CHANG: I lost the date, but you confirmed it. November. When we were in there in November for the exit meeting, we also did a two-day audit before the exit meeting and after the two-day audit, we concluded that everything is well take care of. Then we went to the exit meeting and closed every item.

Now the two open items we talk about,

one is not in the Audit Team's territory and the one of the containment drywell liner that is discovered after some other industrial activities. So it's not obvious at the time of audit. So I would say I'm very satisfied and also glad about the results of the audit, documented audit report which is close to 600 pages. Then you move on and at the appropriate time, I would supplement you.

MR. LE: Thank you, Dr. Chang.

MR. BARTON: I have a question before you get too far. In the audit report, you guys came up with an RAI regarding some heat exchangers. I didn't see anything in the SER on this. Has this been resolved? It's RAI 3.4.1(a-1). Is that still an open item or has that been resolved by the staff?

DR. CHANG: Is it an Audit Team's activity or is that a staffs activity?

MR. LE: That's a staff activity.

DR. CHANG: Could you point us to the right staff to address this?

MR. BARTON: You can continue, but I need an answer to that before we break up.

MR. LE: Section 3.4.1 (a-1).

MR. BARTON: You don't have to look it up now. Just keep going. I need an answer before

we adjourn here.

MR. LE: All right. We'll get back to you. As Dr. Chang has pointed out, the second phase of audits was performed and this time the Applicant personnel outnumbered the staff in contrary to the first one. Out of this audit and other reviews, there was five new AMP programs brought in and 23 more commitments were made by the Applicant. Next slide please.

During the AMP review, there was some programs that are consistent with the GALL report, some that would need enhancement. The staff would like to provide some examples of the enhancement. The bolting integrity program was added. This is a new program and the Applicant committed to implement the bolting integrity program for both units in Commitment 33 and 31 for Units 1 and 2. Next slide.

DR. CHANG: Hold it. Let me supplement that. This is hard to believe that the original application doesn't have aging management of bolting. What we're saying is the bolting integrity of different bolts are not covered by one AMP in total but is spread out in five or six different AMPs on the ISI. So this bolt may be covered by IWP and that bolt may be covered by IWC. So if the

bolting issue, the aging management of bolting, aging effect of bolting, is covered by five or six different programs, how would you expect the staff, the audit team, to be able to review everything without negligence, without neglecting?

So we started that up with the Applicant to say we prefer you to put all these elements from different IWP, IWC, BEF, GIL, all this, into one program. We handled this collectively with the technical staff in the headquarters.

We set up a conference call, Audit team onsite with Tommy and the technical staff, some of them even presented here in the EMCB area, in the old Material Branch area, and we have the Applicant's program owner and also the License Renewal Team members. We all go through a conference call like an hour or an hour and a half. Finally, we come to the conclusion to say this is something that needs to be done for your own sake, for easy tracking, for easy follow, put in one program. So that's a new program that was constructed through the audit activity.

MR. LE: Thank you, Dr. Chang. On this slide, the next one, there's the BWR vessel internal program. Next slide, and this program is consist

with enhancement and among the enhancement the Applicant committed to 100 percent inspection of the top line for Unit 1 and it's a commitment today.

In the next slide, we talk about Reactor Vessel Surveillance Program. This is a program where the Applicant managed the loss of structure toughness due to neutron irradiation embrittlement in the RV beltline reactor vessel. The program is based on the integrated surveillance program criteria in the VIP-78 and VIP-86. The enhancement for this program is at the -- They were enhanced to include the conformance to the updated integrated surveillance program of the VIP-116 and I believe this has been approved by the staff.

DR. CHANG: A clarification. This Commitment No. 22 for Nine Mile Point 1 and Commitment 20 for Nine Mile Point 2 was volunteered by the Applicant. It was not as a result of the Audit Team's findings, but we are presenting to you what programs are being enhanced to meet the core requirements or meet the BWR/VIP requirements. The Audit Team just concurred with it.

MR. LE: I think they see in your eyes that they volunteered.

DR. CHANG: That's another way of saying

it.

MR. LE: Next slide. No. 18 please. We're talking about Unit 1 control rod derive stub tubes penetration. This is for Unit 1 only. Originally Unit 1 stub tubes were repaired by the roll and expansion technique with an allowance for some amount for the RCPB leakage and they plan to implement -- N-730 if approved by the NRC staff and this was made in Commitment 36. At Nine Mile Point we implement, should the leakage appear later on during the period of extended operation, the Applicant committed to implement zero leakage permanent repair and that's in Commitment 36. It was discussed by the Applicant previously.

DR. CHANG: Let me supplement on this Commitment 36. The original was the original Commitment 36, the first half. The first bullet is the original commitment and then the second one is still say Commitment 36, but that's a different Commitment 36. It's a Modified Commitment 36. After the Audit Team through the audit, we proposed change of the original Commitment 36 to make a new Commitment 36. So this Commitment 36 if you compare the time line before and after, they're not the same.

CHAIR SIEBER: Okay.

MR. LE: Next slide. Unit 1 Emergency Condenser, this is designed for emergency condenser fissure and belt welded to the emergency condenser shell that are not designed to be removed. Therefore eddy current testing is recommended by the GALL report but the tipping ising not possible. So during the audit and review, the Applicant provided the spaces for not performing the eddy current testing and committed to implement a leakage test to detect small leak and this is Commitment 29 for Unit 1. Next slide.

CHAIR SIEBER: And the staff is satisfied with that?

DR. CHANG: Yes. The staff, we, spent a considerable amount of time on this emergency condenser. The staff reviewed the basis for the Applicant to take the exception of not performing the eddy current testing and we agree with that reason why it cannot be performed. But the Applicant provided an alternative. It's through the performance monitoring system. In this area, I would suggest to my Assistant Team Leader, Robert Hsu, to talk about it. Robert.

MR. HSU: Yes. My name is Robert Hsu.

The staff provided the reason we accept that because previously 1997 they appraised that. They already have a 32 year appraisal and the reason, the first thing is they have replaced a brand new better quality material resisting degradation. That's the first thing. Second thing, they implemented a better water chemistry program and the third, they also install an online system which is going to monitor the water level which eliminated the cause of the previous cracking degradation. And the next one is they also provide a commitment that they're going to do the leakage test, the leakage test which is able to detect a leakage. So based on all this and the process of additional irradiation monitoring program and the temperature monitoring which was originally required by the GALL, we accept this position.

MR. BARTON: What was the change in the -- You said the chemistry program was changed, water chemistry.

MR. HSU: Yes. The better water chemistry program.

MR. BARTON: What was better about the water chemistry program? You have -- water on one side of the reactor coolant and the other. What's

better? What did they do better than they were doing before?

MR. HSU: They have a better consul and they have much good operating experience and with hydrogen water.

MR. BARTON: I don't know if hydrogen water helps you up in isolation condensers.

PARTICIPANT: Was it water chemistry or was it control of the water level?

DR. CHANG: I think it was the control level.

MR. BARTON: That I'll buy.

DR. CHANG: Yes.

MR. BARTON: I don't buy a change in water chemistry though.

DR. CHANG: Control of water level, remove the transient which put the tubes in a cold and hot position, up and down all the time. You remove the stressor of the tubing, that kind of thing.

MR. BARTON: All right. That makes sense. All right.

DR. CHANG: Thank you for your clarification.

MR. BARTON: Your clarification. My

question.

DR. CHANG: I only picked up on what you had started.

CHAIR SIEBER: I guess I would comment a little bit about this explanation. It's unfortunate the isolation condenser was designed this way and probably should not have been even though I suspect that it met the B-31.1 Code which preceded the ASME Code that most of the plants were built in accordance with. On the other hand, when you do a leakage test, those are usually done at operating conditions and the presumption if you find a leak is that a crack has already occurred and since it's already occurred, there is no margin to crack.

On the other hand, a typical eddy current in-service inspection looks for wall thickness and says if you have anything greater than 40 percent through-wall reduction, then under design conditions which is much higher than a leakage test there is some probability that you'll have a leak. So there is inherent in this alternative a reduction in margin. Whether that reduction results in any kind of a hazard is another question, but in my view, it's not an even exchange.

DR. CHANG: It's not a superb design.

CHAIR SIEBER: It is not. That's an understatement.

DR. CHANG: Yes.

MR. BARTON: They didn't build too many plants with some kind of --

CHAIR SIEBER: That's right.

MR. BARTON: Although this is simple design.

DR. CHANG: But given that -- I agree with everything you say, but given the situation, it's already there. What Nine Mile Point has done is the best they can do, use better material, to remove the loading, to remove the stressor and also it's new.

CHAIR SIEBER: On the other hand, you have no way to predict what time in the future a crack or leakage will develop either. So that's another piece that you're missing. I guess I have thought about this a lot and I raised this in my letter to John a week ago or ten days ago so that we could discuss it here today and I'm not prepared to say that the staff or the Applicant is wrong. It's just that I do see it as a reduction in margin.

MR. LE: Thank you, Dr. Chang. The next slide, No. 20, we would like to report about the

non-EQ inaccessible medium voltage cable program.

MR. BARTON: That should have been red flag.

DR. CHANG: Ken Chang. It's a red flag, but I assure you that the Audit Team is not going to let those kind of issues go on without being noticed.

MEMBER BONACA: But I noticed that they're all under the problem of Unit 2. So there are no medium voltage cables in Unit 1.

DR. CHANG: There is not inaccessible medium voltage cables.

MEMBER BONACA: Yes, that's right.

DR. CHANG: In Unit 1.

MEMBER BONACA: Not one?

DR. CHANG: The Audit Team in that specific audit, we picked an electrical expert from the tech division of Duc Nguyen. Is Duc there?

MR. NGUYEN: My name is Duc Nguyen. I am a regional from the Division of Engineering and I try the License Renewal request of Dr. Ken Chang. I have reviewed a lot of applications. Go back to the Nine Mile Point and the reason why the Nine Mile Point 2 and Nine Mile Point 1 are different is because Nine Mile 1 they don't have the cable in the

scope of the inaccessible medium voltage cable. Either they have above the crow or they are low voltage. They don't have the medium voltage inaccessible cable. 9.2 they have and we during the review process identified at least one. The -- water cable you can count most of them inaccessible.

So that we identified at least one cable in Unit 2 and we request the Applicant to go back and do the review. And we had a meeting at around 4:00 p.m. and they had to stay overnight to bring all the drawings on the site and they identified an additional 18 cables.

MR. BARTON: Are they all on Unit 2?

MR. NGUYEN: Yes, because Unit 1, they don't have any cable that's in scope. To be in scope, you have to have the cable in scope of license renewal and you have to have to medium voltage from two -- to 35 -- and then you have to subject to the water -- phenomena. That means underground and inaccessible. Unit 1 they have above the ground, the cable, the surface water cable I believe and all the cable would be low voltage and if you know the water --phenomena is proportionate to the level of the voltage, especially medium voltage cable.

MR. BARTON: Thank you.

MR. LE: Thank you, Duc. As an added value during the staff audit with the Applicant, we also ran into the situation where Duc found that the insulation testing of the cable and the motor they tested it with both cable and motor together and so the staff pointed out that that wouldn't tell about the insulation of the cable. So the Applicant are reviewing it and they should be testing the insulation separately rather than together.

CHAIR SIEBER: Right.

MR. LE: The next slide please. On the Slide 21, we would like to report the overall managing of all the systems, 3.1 reactor vessel. For Unit 1, we found that there are 15 AMP that the Applicant are using to manage the aging effect and for Unit 2, there are 14 AMP. For engineering safety system, there's a nine AMP for Unit 1 and eight AMP for Unit 2. For auxiliary system, there are 17 AMP for Unit 1 and 15 AMP for Unit 2. For steam and power conversion, there are 17 AMP for Unit 1.

CHAIR SIEBER: Nine.

MR. LE: Nine, I'm sorry and six for Unit 2.

MR. BARTON: What do these numbers mean? Are these numbers significant in any way? So what?

MR. LE: Those are the numbers of the AMP. I'm just trying to say that we reviewed all the AMPs in the system.

MR. BARTON: All right. So you reviewed them all. So the numbers generally don't mean that much here.

MR. LE: Yes. That we found.

DR. CHANG: I take a different interpretation of the data. This is indicating that when we review the AMRs we also revisit this many AMPs because this many AMPs are the ones the ARM is relying on to manage that. So we're not just saying it's 3.1. We only look at three AMPs.

MR. BARTON: Okay. So you've looked at them all.

DR. CHANG: Right.

MR. BARTON: So you have to say "Just looked at them all."

DR. CHANG: Yes.

MR. BARTON: End of slide. Next slide.

DR. CHANG: Right. Next slide.

MR. LE: Next slide. All right. Next slide. We reported earlier we had two open items.

This is the first item in the Nine Mile Point 1 drywell liner. After the audit, the staff really reviewed all the documents and noted that the Applicant had a report in refueling outage '03 that they found 360 degrees rusting around the drywell interior and so the staff wasn't sure what corrective action and preventive action to mitigate future corrosion.

So we identified this at the time when we were producing the safety evaluation report.

We identified an open item and two weeks ago, we met with the Applicant on March 27 to talk about what they found and why they did not take any corrective action and report it in the DER. During that meeting, the Applicant also provided us an overall operating experience with no corrosion found outside of the drywell and none inside except for those that report at elevation 2 and 25 feet.

Yesterday, the staff received a letter from the Applicant to report that they are ready and propose a program for the supplemental inspection of the drywell. That letter had been received from the staff and under review and, Hans, can you tell us what the status of the review is?

MR. ASHER: I am Hans Asher from

Division of Engineering NRR. Yesterday when Tommy sent us the email with the Applicant's program, I was unable to open the email at that time. In the morning I opened it. I printed it out, but I didn't have a chance to look at it and evaluate it. So I can't tell much, but based on what I've seen during their presentation on March 27, it looked like they voluntarily put the refueling seals into the scope of license renewal. That made me happy that the chances of hitting the upper part of the drywell hitting corrosion are remote.

Also they took actions here and they found something in 2003 which looks like a positive actions but I want to evaluate a little more to see because it's an uncoated area and the geometry is such that if there is any water or moisture it may go near the concrete and is it going to affect that concrete shell. So I'm going to evaluate it and call a teleconference if I need to and work on it.

MR. LE: Hans, can you stay there? In the next slide, this slide was provided by Hans and Dr. Chang. Can you explain the meaning of your slide?

MR. ASHER: The Subcommittee has seen this slide for all the plan before. Most of the

fundamentals that we have identified in GALL and they provided the reasons for it and they are all within the special limits that we had established.

MR. LE: All right. Thank you. In the next slide --

DR. CHANG: Hold a minute. Ken Chang. Before we leave Section 3, I would like Robert Hsu to address that one heat exchanger item that -- identified. Robert, are you ready to talk about it?

MR. HSU: Okay. The heat exchanger item which originally was raised by the technical staff and the technical staff asked this question and then they addressed in the SER.

MR. BARTON: It is addressed in the SER?

MR. HSU: Yes.

MR. BARTON: Okay. So the staff is satisfied with the response.

MR. HSU: Yes, the staff accepts the response.

MR. BARTON: Okay. I just wanted to make sure it was tied to the SER because it was hanging out there in the audit report. I didn't know where the closure was. Okay. Thank you.

MR. LE: That is the end of the Section 3.0. The staff would now like to brief the result

of Section 4, the TOAA. This is a very unique review. The staff had not found for Section 3.1 the identification of TOA within the expectation of regulation.

For 4.2, the reactor vessel neutron embrittlement or the analysis reported in the application were acceptable by the staff.

Section 4.3, metal fatigue, the Applicant had committed to implement the FatiguePro monitoring software and this has the Commitment 5 for Unit 1 and Commitment 4 for Unit 2.

For 4.4 TOAA addressing the equipment qualification of electrical equipment, the Applicant has stated that the EQ program together with other plant programs will adequately manage the aging effect of all the EQ during the period of standard operation. The staff found it acceptable.

And Section 4.5 is not applicable. It's a concrete containment tendon prestress with only for the pressurizer.

4.6 Containment line plate, metal containment and penetration fatigue analysis, the Applicant had provided adequate evaluation to demonstrate that the fatigue uses are not exceeded during the period of operation and the Unit 1

fatigue monitoring program for the torus attachment typing and Unit 2 torus margin program will adequately manage the aging effect for this feature.

Previously, the next slide, on Section 47, the other plant specific TOAA, the evaluation for Unit 2 bioshield had been identified as an open item and the reason for this as the Applicant pointed out that the methodology for fluent calculation were not an NRC approved methodology. At this point, I would like to call on Jim Medoff to report to the committee what is your review because the Applicant has submitted a letter on March 23 to propose the resolution to close this item.

MR. MEDOFF: Good morning. I'm Jim Medoff with the Division of Component Integrity. I was responsible for reviewing the time limiting aging analysis for the bioshield. Basically, the Applicant identified this as a TLA because they had discovered a number of flaws in their bioshield at Nine Mile Point Unit 2 and they had done a dynamic crack growth fracture mechanics evaluation to justify further service of the flaws.

The flaws that were unacceptable were repaired by the Applicant prior to continued service. The reasons it's a TLA is in the analysis.

They had a set a maximum fluence on the bioshield for the dynamic crack growth fraction mechanics analysis. So they had identified the analysis as a TLA for the facility.

Originally, they were proposed to disposition this under a single I criteria meaning that the fluence for the bioshield through the extended period did not go above the fluence in the assessment and therefore the evaluation was still bounding. But the staff determined that they had used an unapproved fluence methodology for the bioshield and we requested that they submit an updated fluence methodology that would conform to Reg Guide 1.190 and we had our fluence expert, Dr. Lambros Lois, review their methodology.

We were going to originally disposition this through a commitment and the reason it's an open item is OGC had put a legal objection on that saying that if we were going to wait for an updated fluence assessment later on that would avoid due process. So we issued an open item on it.

Subsequent to that time, the Applicant had sent in two responses, one in a docketed letter to the staff and one in a docketed email to the staff, that provided an updated fluence value for

the bioshield that was done in accordance with an approved methodology and we had Dr. Lois review that. We determined that the fluence was less than the fluence threshold for an embrittlement of phreatic steels in 10 CFR Part 50 Appendix H and we agreed that the analysis, did not need to be identified as a TLA for this.

CHAIR SIEBER: So this open item is essentially complete and will go away.

MR. MEDOFF: The open item will go away.

CHAIR SIEBER: And months of paperwork.

MR. MEDOFF: And actually the two sections of the LRA associated will be deleted from the application.

CHAIR SIEBER: Okay. Thank you.

MR. LE: Thank you, Jim. The two open that the staff had reported previously, one is now considered close and we will take the necessary paperwork to report this in the final SER. For the containment corrosion, the staff will continue to discuss the technical concern and when it resolves, it will be documented in the final SER.

In the next three slides -

MEMBER BONACA: I have a question about the core shroud repairs. They were never considered

as part of TLAs. Right?

MR. LE: No. Meena, can you comment on that?

MEMBER BONACA: The clamps. I'm thinking about the clamps that are being installed on the shroud.

MS. KHANNA: Right.

MEMBER BONACA: They were never included as TLAs.

MS. KHANNA: No, that's correct. They were not.

MEMBER BONACA: Although they really are planning to manage aging of those components.

MS. KHANNA: Through the BWR.

MEMBER BONACA: As you would do as possibly for a TLA.

MS. KHANNA: Right. That's correct and that's going to be handled through the BWR vessel internals.

MEMBER BONACA: Okay. So that's why it was excluded from the TLAs. Okay.

MR. LE: Meena, please stay there. In the next three slides, we would -- actually a Brunswick meeting. So we summarized these values in the SER in the table and we would like Meena to walk

us through Slides 26, 27 and 28.

MS. KHANNA: Okay. Hello. My name is Meena Khanna and I'm with DCI. Based on lessons learned as Tommy had indicated from the Brunswick Lessons Renewal ACRS meeting, we walked away with a few -- We decided to include a few more slides to our presentation. But I do want to note that these charts are actually not included in the current SER but we will definitely include them in the final SER because we do believe that it does clarify how our assessment was performed on upper shelf energy and was on the reactor pressure vessel circ and axial weld failure probability analysis.

On this first chart, you can see we have the three beltline materials listed for Nine Mile Point Unit 1. The acceptance criterion, basically there are two acceptance criterion. There is one that's required by 10 CFR Part 50 Appendix G which requires you to have an upper shelf energy value of at least 50 foot pounds where you'll see that the circ weld for Nine Mile Point 1 meets.

The other one is because they were not able to meet that value, were not able to demonstrate an upper shelf energy value of 50 foot pounds, they performed an EMA which was approved

through the BWR VIP74-a report. The staff provided an SER on that. We did approve that methodology and basically for Nine Mile Point 1 boiler shelf plates because that's a BWR-2 design in the 74-a SER as approved by the staff, we have an acceptance criteria of less than 29.5 percent drop in the upper shelf energy foot pound value.

You'll be able to see. We did compare -- Well, actually we performed our own analysis of the upper shelf energy values and then compared them to the criteria as required in the 74-a report or 10 CFR Part 50 Appendix G. You'll see that their values are definitely below the acceptance criteria. We were able to conclude that they satisfactorily satisfied 10 CFR 54.21(c)(1)(ii).

If you go to the next slide, for Nine Mile Point 2 you'll see that they definitely were in agreement and did satisfy the requirement of 10 CFR Part 50 Appendix G of projecting upper shelf energy values of greater than 50 foot pound.

The last slide is actually a slide on the injector vessel circumferential weld relief and reactor vessel axial wall probability of failure analyses. BWR VIP 05 which the staff has also approved states that you can justify your acceptance

criterion as justified -- Okay. Let me get this right. Sorry. Let me start from the beginning.

For limiting circ welds and you can state that this was not applicable for Nine Mile Point 2 because they had not submitted a relief request for the elimination of circ welds inspections. You'll see that we only approved it for Nine Mile Point Unit 1 which they had identified.

The acceptance criterion that the staff used is based on the staff's SER of the BWR VIP 05 report. The Nine Mile Point 1 welds are fabricated from CE welds and in the VIP 05 report the acceptance criterion for CE welds is less than 113.2 degree Fahrenheit Mean RTndt. So if you look at the Nine Mile Point 1 values, they are very low. We did confirm. We came up with 22.5 degrees Fahrenheit of the Mean RTndt which is definitely well below the acceptance criterion of 113.2. I do want to note that these values are very low because those welds have very low copper chemistry values.

And then the same thing was done for limiting axial weld. The acceptance criterion that was accepted in the 05 SER, the BWR VIP 05 SER, is less than 114 degrees. The staff did its own

calculations of the Mean RTndt values and came up with 31.0 which is very close to what Nine Mile Point came up with and which is also well below the 114 degrees Fahrenheit Mean RTndt that's accepted in the staff's BWR VIP 05. We were able to conclude that these TLAs did meet 10 CFR 54.21(c)(1)(I) or (ii).

MR. LE: Thank you, Meena.

CHAIR SIEBER: Thank you.

MR. LE: With Meena's input --

MR. FAIR: Hi, this is John Fair with NRR Division of Engineering. I just wanted to make one point of clarification on the core shroud repair. There was a TLA associated with it as discussed in Section 4.3.5 of the staff SER and basically what it was they had a relatively low fatigue usage for the core shroud repair and so extrapolated out for 60 years it's not a problem. But it is discussed in the SER.

MEMBER BONACA: I saw it. Thank you, John.

MR. LE: With that input from John, the staff now makes conclusion on the TLA review. We were able to close the open item in Section 4.7 and now the staff has concluded that TLAA list is

adequate according to 10 CFR 54.3. The analysis provided were valid for the period of standard operation according to 10 CFR 54.21(c)(1)(I). The staff concludes the analysis that projects by the Applicant to the end of POE in accordance with 10 CFR 54.21 (c)(1)(ii). And the aging effect will be adequately and sufficiently managed for the extended period of operation in accordance with (iii).

The staff also concludes that that the supplement to the FSAR has been sufficient and adequate as required by 10 CFR 54.21(d) and there are no plant specific exemptions that have been requested as stated in the 10 CFR 54.21(c)(2). With all the previous details, findings from the staff and the Audit Team and the regional inspection, the staff now would like to report to the Subcommittee that the staff has now concluded that there is reasonable assurance that the activity authorized by the renewal license will continue to be conducted in accordance with the current licensing basis and that any changes made to the Nine Mile Point Nuclear Station CLB in order to comply with the 10 CFR 54.29(a) are in accord with the Act and the Commission regulation. That ends the briefing.

CHAIR SIEBER: Okay. Thank you very

much and I would like to thank the staff for all their work in preparing the safety evaluation and their work in preparing for today's presentation.

Now the process that we go through, this is a subcommittee meeting of the Advisory Committee on Reactor Safeguards. We have a statutory responsibility under the Atomic Energy Act of 1954 as amended to review granting of new licenses or the extension of the term of any license and therefore, before the Safety Evaluation Report is complete, we will prepare a report which will be come Section 5 of the Safety Evaluation Report.

Now this is an interim meeting. We have interim meetings when the bulk of the work has been done in preparing the application that's been submitted and the bulk of the review work is done so that if there are issues that are of concern to the Advisory Committee that might impact the granting of a license extension or impact some aspect of the future operation of the plants so that the Advisory Committee can alert both the staff and the Applicant of that condition.

If that is the case, we would write an interim letter report and provide it to the staff with our views on the issues that are outstanding of

the subject of our concern. On the other hand, if you don't get a interim letter, that does not mean that school is out and everything is perfect. It means that the application and the safety evaluation are progressing along a path that we consider to be satisfactory and that there is a probability that license renewal will be granted provided all the commitments are completed. So you have to watch your mailbox to see if you get a letter or not.

On the other hand, after our second meeting where all of you will appear before the full committee, there must be a report or you don't get a license renewal. So we're in the first step of that process which is an interim review and it may or may not result in an interim letter. After seven years of being on the Advisory Committee on Reactor Safeguards, I have learned never to predict what the full committee will do when it attempts to reach consensus and I am not going to change my method of operation today. On the other hand, if there is an interim letter, I will be the first drafter and typically not the last drafter of such a letter.

I would be interested in hearing from Committee members as to their views first of all regarding the application, secondly, the staff's

review, issues of concern to them, and lastly, whether if they were acting on their own they would write an interim letter and what the contents of that letter would be. And I'll make it easy. I will be last. That makes it easy for me, but I would like to ask --

MR. BARTON: Before you start that process, may I ask a question?

CHAIR SIEBER: Sure.

MR. BARTON: I noted, and I didn't reference where I noted this, there are service water tunnel on Nine Mile 1 exhibit leakage and it was subsequently repaired from inside the tunnel and the question is is there any program in place, management program, to inspect the tunnel for other cracks or leakage paths in the future and I couldn't find the answer to that anywhere. I don't know who to address that to, to Applicant or the staff.

MR. LE: Can the Applicant take that?

MR. MAZZFERRO: This is Pete Mazzferro from Constellation Energy. The service water tunnels are in an aging management program and they're covered under our structures monitoring program in which we do inspections every two years.

MR. BARTON: Thank you.

DR. CHANG: This issue was discovered in the third first-stage audit which was held at Crofton. At that time, this issue was heavily reviewed.

CHAIR SIEBER: Okay.

MR. BARTON: Thank you.

CHAIR SIEBER: Thank you. Well, John, I would like to ask your opinions on the four questions that I asked and any others that may have.

MR. BARTON: Where are those four questions written?

CHAIR SIEBER: One of them dealt with the application and its adequacy, the second the staff's review, third your concerns, fourth, if you would write an interim letter.

MR. BARTON: I'll start at the end with interim letter. I'm not sure an interim letter is required. I think full committee ought to be appraised of what are "the issues" of this application and basically the containment issues. The final application was fine. I just don't know why it took so long. We had an explanation, but I think that the job done initially was sub par. And after all these applications we've reviewed so far, I just wonder this far down the path why we had to

go through some of that. There's a lot of experience out there on what constitutes a good application and somebody didn't -- We heard the explanation, organization or whatever. But the final application, I don't have any problem with.

I think the staff did a good job of reviewing the application, came up with a lot of issues and commitments. I don't have any issue with the SER. I thought the SER was done fine.

CHAIR SIEBER: And thank you. Let me add one thing. We discussed this briefly before, but the root cause of the original application problems, one of them was isolationism.

MR. BARTON: Right.

CHAIR SIEBER: And my experience in the industry over 30 years that was viewed by a number of plants as a good way to be. You know stay low in the grass and the inspectors won't come by. Don't mess up. You don't get in the newspapers and that's a mistake. It really is.

In order for you to run a good plant, you have to know what everybody else is doing because you can't by yourself think of everything. Somebody else will have thought about this issue and another plant will have thought about that issue and

that's why there's industry groups. That's why there's INPO. That's one of the functions of the NRC is to make sure that people are aware of the latest in technology and the advances in the process of operating and maintaining a plant.

So isolationism doesn't work. If we're seeing that at this day and age after an industry that's basically been around for 40 years, I think we all need to take that to heart and make sure that it doesn't persist in the future.

MR. BARTON: I think they made a lot of changes as a result of that.

CHAIR SIEBER: I do too.

MR. BARTON: I guess what I'm disappointed in is that it was able to get that far without the organization recognizing it and correcting it before it got to the staff telling them "Hey, your application is really not adequate."

CHAIR SIEBER: You can overcome one mountain. On the other hand if isolationism is built into the culture, you have to change the culture.

MR. BARTON: You're looking at safety culture issues now.

CHAIR SIEBER: Not this morning. Later

in the week. Okay. Thank you, John.

MEMBER MAYNARD: As far as the Applicant's concerned, it obviously got off to a shaky start. It looks like a number of good corrective actions have been taken. I think we've beaten this issue almost to death. I think it's something that both the Applicant and other applicants need to be conscious of and pay attention to in the future, but it looks like they have taken a number of good aggressive actions.

As far as the staff's review, it appears to be very thorough. It appears that they were instrumental in identifying some issues to the Applicant that resulted in good corrective actions by the Applicant. So overall, I think the staff has done a good job and in fact, the SER reflects that.

As far as issues, we discussed a couple of them. The inability to do eddy current testing, a little bit of a concern. However, with the actions taken, I'm not sure that that's really a degraded margin. It's actually probably an increase in margin over what they had for the first 30 years. So that's an issue that it would be better if something else could be done. But without that, it looks like the appropriate actions are being taken

there.

I personally don't see any value added at this point for us to put an interim letter in. I think issues have been discussed or known and they're being worked on and I'm not sure what value added it would be for an interim letter.

CHAIR SIEBER: Dr. Shack, would you like to comment?

MEMBER SHACK: It seems to me that in the essence that license renewal is really focused on the managing of the aging of the passive systems, I think they've done a pretty good job with their reactor internals, their piping. That's the replacement in the Unit 1 and essentially a good material to start with in Unit 2. They've been aggressive in the water chemistry with the hydrogen control and the metal addition. So I think they've done a good job of managing the aging of those passive systems which again is a large part of the license renewal process.

CHAIR SIEBER: Thank you. Dr. Wallis.

MEMBER WALLIS: You should really hear from the other first since I missed part of this. I think that the licensee's fulfilling the requirements of the regulations as far as I can

gather and I think the staff has checked those requirements well. I did raise the question of coatings. I don't know what the staff had to say about that, but it's a message I take away I think for maybe a different place where we ask about that issue because apparently the NEI guidance has been approved and they're doing what they're supposed to do. But it may not be in the future the right thing to do. That's a different issue though. I don't want to hold things up for that.

CHAIR SIEBER: Dr. Bonaca.

MEMBER BONACA: First of all, I would like to recognize the staff for having done the job of identifying the shortcomings and leveraging those with the licensee and I think the licensee then did a decent job of bringing back and to correcting the scope and so on. I think all in all the application is pretty complete. I see a couple of open items and they seem to be appropriate in needing closure. I think the SER was complete, one of the heaviest SERs we have received to-date.

And I don't think we need to write an interim letter. I think that the issues are pretty clear and I haven't heard from anyone to bring in an issue other than the two that are being addressed as

open items and we of course will review those in the final review of the final SER. So I have no further comments.

CHAIR SIEBER: Sam.

MEMBER ARMIJO: My view is both the Applicant and the staff have done a very thorough job. I also don't see a need for an interim letter and on the issue of the isolation condenser, absence of eddy current testing, I'm not sure that an integral leak test isn't really better since it's a 100 percent system test of the function which can be done frequently as opposed to infrequent spot checks using eddy currents which aren't 100 percent reliable anyway. So I'm not so sure that's a big loss as far as being reasonably sure that function condenser will be met. Overall, I'm satisfied.

CHAIR SIEBER: Okay. Thank you. So far we have a number of votes that say no interim letter, but that's no everybody. So we'll find out later this week.

MR. BARTON: We always have the right to change our minds before.

CHAIR SIEBER: Right. You can change your mind at any time, but in any event, my own comments and conclusions, I agree that the

application, the amended application, is satisfactory. In fact, I thought it was pretty thorough. It's about double the size of the safety evaluation report and I think it's complicated by the fact that the units are different in time and different in basic design concept and so it took me a little bit of extra time to study exacting what the issues were between the units and how they fit into the time frame. You're almost running out of time on Unit 1. Unit 2 you have a lot of time left since it only went on line in 1987 or 1988.

On the other hand, it's none too soon to be implementing these programs. Some of these commitments have to be implemented within the next year which to me is going to be a tight schedule. It's going to take a lot of effort to do that.

As far as the staff's SER is concerned, I think the staff has exercised good judgment all the way through. I think the SER is well written and I continue to congratulate the staff becoming more efficient and more thorough in the processing of these applications and I think that's good for applicants and it's good for the Agency and it's good for the public safety when you're thorough and decisive as the staff demonstrates that they are.

I also don't see a need at this point for an interim letter because I think issues that are there that I would be concerned about are well known by everyone and have been identified by both the applicant and the staff and are on their way to being resolved. So I'm not sure that there would added value in writing an interim letter, but I'll find out in the next couple of days.

MR. BARTON: Is the full committee going to hear some presentation?

CHAIR SIEBER: From me.

MR. BARTON: From you. Okay. I understand.

CHAIR SIEBER: I will just give a verbal report.

MR. BARTON: So you'll highlight five or ten issues.

CHAIR SIEBER: Yes.

MR. BARTON: All right. That's good.

CHAIR SIEBER: I will just go through the 80 or 90 slides that I have very quickly. With that, if anyone has any comments that they would like to make. Lacking any comments, I appreciate the time and effort spent by the Applicant, Constellation Energy, and by the staff including the

Region I staff who did a fine job in audits and inspections in this program. If there are not further questions, I think that we can adjourn this Subcommittee meeting. Off the record.

(Whereupon, at 11:45 a.m., the above-entitled matter was concluded.)

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 Meeting

Docket Number: n/a

Location: Rockville, MD

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

Lindsey Barnes
Official Reporter
Neal R. Gross & Co., Inc.

Constellation Energy

Nine Mile Point License Renewal Units 1 and 2

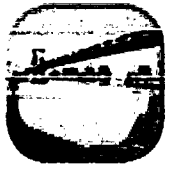
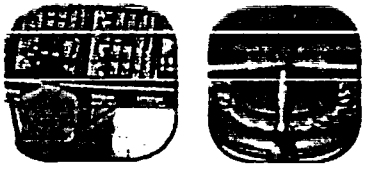
Presentation to ACRS LR Subcommittee

April 5, 2006

Tim O'Connor
Mark Flaherty
David Dellario
Pete Mazzaferro

The way energy **works.**™



In Attendance

- Tim O'Connor - Vice President, Nine Mile Point Nuclear Station (NMPNS)
- Mark Flaherty - Acting Vice President, Constellation Energy (CE) Nuclear Technical Services
- David Dellario - Director, CE Fleet Licensing Projects
- Robert Randall - Director, Ginna Licensing
- Raymond Dean - Director, NMPNS Quality and Performance Assessment
- Peter Mazzaferro - NMPNS LR Project Manager
- Michael Fallin - NMPNS LR Project Lead
- Ken Haws - NMPNS LR Project Lead
- Dale Goodney - NMPNS Design Engineering
- George Inch - NMPNS Design Engineering
- Jeff Poehler - CE Nuclear Technical Services
- Carl Senska - NMPNS Chemistry

Agenda

• Description of NMPNS	T. O'Connor
• Current NMPNS Performance	T. O'Connor
• License Renewal Recovery Project	M. Flaherty, T. O'Connor, D. Dellario
• Operating History	P. Mazzaferro
• Plant Improvement Initiatives	P. Mazzaferro
• Aging Management Programs	P. Mazzaferro
• License Renewal Commitments	P. Mazzaferro
• Summary	T. O'Connor

Description of NMPNS

- Nine Mile Point Nuclear Station (NMPNS) owners:
  - CE - 100% of NMP1 & 82% of NMP2
  - Long Island Power Authority - 18% of NMP2
- CE effective ownership date:
  - November 11, 2001
- Operator: NMPNS
- Location: Lycoming, NY
- Ultimate heat sink: Lake Ontario
- NSSS and turbine supplier: GE

Description of NMPNS Units

- NMP1 Specific Information
  - BWR2 - Mark I Containment
  - Rated Thermal Capacity: 1850 MWt
  - Rated Electrical Output: 615 MWe
  - Commercial Operation: 12/1/69
  - License Expiration Date: 8/22/09
- NMP2 Specific Information
  - BWR5 - Mark II Containment
  - Rated Thermal Capacity: 3467 MWt
  - Rated Electrical Output: 1144 MWe
  - Commercial Operation: 3/11/88
  - License Expiration Date: 10/31/26 (Exemption from 10 CFR 54.17 granted by NRC)

Current NMPNS Performance

- The current NMP1 and NMP2 ROP performance indicators are green
- There are no open inspection findings with a status greater than green
- NMP1 and NMP2 are in Column 1 of the ROP Licensee Response Column Matrix

License Renewal Recovery Project

Constellation Response

- LRA submitted on May 26, 2004
- In March 2005, CE and NRC mutually concluded there were quality concerns with initial LRA
- CE and NRC mutually agreed that further LRA review be deferred to allow grace period for CE to improve LRA quality and submit Amended LRA (ALRA) to facilitate NRC review
- Performed Root Cause Analysis (Corrective Action Program)
  - Isolationism
  - Management engagement
  - Lack of resources

License Renewal Recovery Project

Corporate Oversight

- Assigned to Fleet Licensing
  - New Fleet Director position established
- Extensive Checks and Balances
  - Key Performance Indicators (KPIs)
  - Challenge Boards
  - Weekly Management Status meetings
  - Periodic meetings with Chief Nuclear Officer and President
- Added Resources

License Renewal Recovery Project

Site Lessons Learned and Application

- All projects/initiatives belong to and are controlled through Site VP
- Pre-established results, interim milestones and metrics
- NMP Staff assigned as a team to Projects
- Validating progress/results through Challenge Boards
- Independent oversight (Corporate/Q&PA/SMEs)
- Site communication for education and engagement

License Renewal Recovery Project

Project Actions Taken

- LR Recovery Project Plan:
  - LR team supplemented with NMP staff and industry experts
  - LR team consolidated at NMP
  - Benchmarking
  - Senior Licensing Consultant added to project
  - Internal and External assessments
  - Extensive use of Challenge Boards to review project products

License Renewal Recovery Project

Focus of Effort

- 3 LR Recovery Project focus areas:
  - NSR Scoping
  - NRC Review Questions
  - Aging Management Programs

License Renewal Recovery Project

Results of Project

- NMPNS submitted ALRA on July 14, 2005
- Addressed NRC-identified quality concerns
- Accelerated transfer of LR knowledge to NMP
- Successful Audit and Inspection

Operating History

Material Issues Addressed & Design Margin Restored

- NMP1 Reactor Recirculation System piping
  - Piping replacement with resistant material
- NMP1/NMP2 Core Shroud
  - Tie rod and clamp repairs (Unit 1)
  - Acceptable by inspections and evaluation (Unit 2)
- NMP1 Emergency (Isolation) Condenser
  - Tubing replaced with resistant material
- NMP1 RBCLC piping degradation
  - Threaded pipe replaced by heavier wall welded construction
- NMP1 Control Rod Drive (CRD) Stub Tube
  - Roll repairs

NMP1 Core Shroud Cracking

- Tie Rod repairs installed structurally replacing horizontal welds H1 through H7 in 1995
- Identified shroud beltline vertical weld cracking in V9 and V10 welds in 1997
- Inspections in 1999 identified an average crack growth rate of ~2E-5 inches/hr
- Peak fluence of un-repaired vertical welds remains <5E20 n/cm^2 - threshold for application of irradiated assisted crack growth effects
- Vertical weld clamps installed structurally replacing V9 and V10 vertical welds in 1999
- Noble Metals applied 2000/HWC started in 2000
- Full vertical weld and ring segment weld inspections performed in 1999
  - Re-inspection interval 10 years
  - Full re-baseline inspection to be completed 2007 and 2009

NMP2 Core Shroud Cracking

- Identified IGSCC cracking in the H4 and H5 welds in 1998
  - 70% circumference (max depth <0.75", average <0.5")
- Completed structural analysis consistent with BWRVIP-76
  - Determined repair not required.
- Reinspected in 2000
  - Identified average crack growth ~1E-5 in/hr
- Noble metals applied 2000/HWC started 2001
- Reinspected H4 and H5 welds in 2004 after 4 years of effective HWC
  - No observed crack growth
- Peak fluence of H4 weld in 2004 <6.5E20 n/cm^2 (E >1MEV)
- Contingency tie rod repair installation planned for operation beyond 2010

NMP1 Emergency (Isolation) Condenser

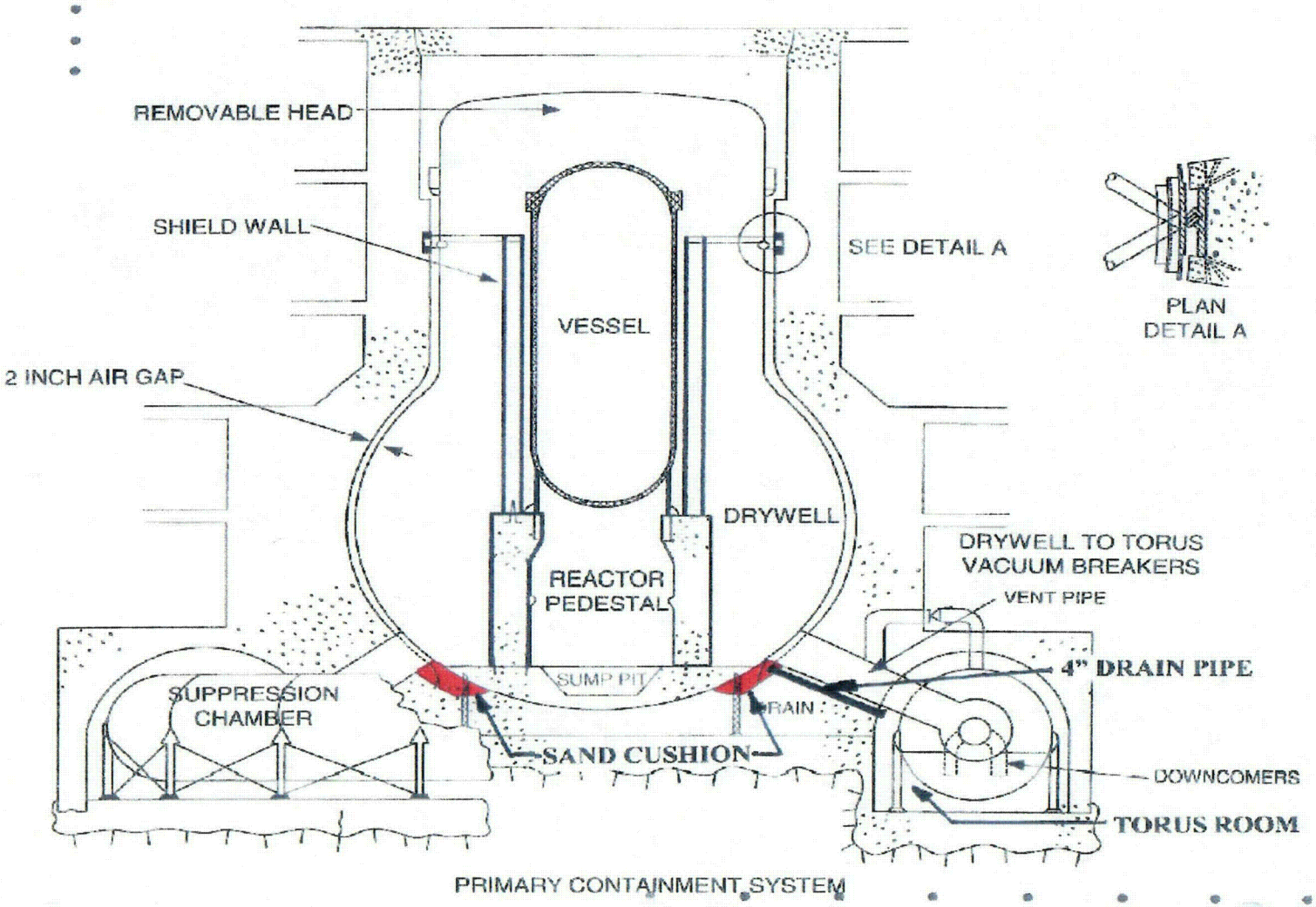
- Identified and repaired tube leaks in 1997

- ECs are of all welded construction - Bases for not performing eddy current testing:
  - Conditions and stressors that were precursors to SCC have been eliminated
    - Lowered temperature of tube and shell side water
    - Maintaining water chemistry on tube and shell side
    - Susceptibility of tubes to SCC reduced by modifications
    - Use of 316L SS tubes and tubesheets
    - Installation of a Keep Fill System to keep tubes flooded & to eliminate thermal cycles
  - Monitoring and detection to ensure adverse conditions will not recur
    - Temperature
    - Water Chemistry
    - Radiation from vents
  - Tube leak test to assure heat transfer intended function is not compromised
  - Periodic performance testing of the HXs

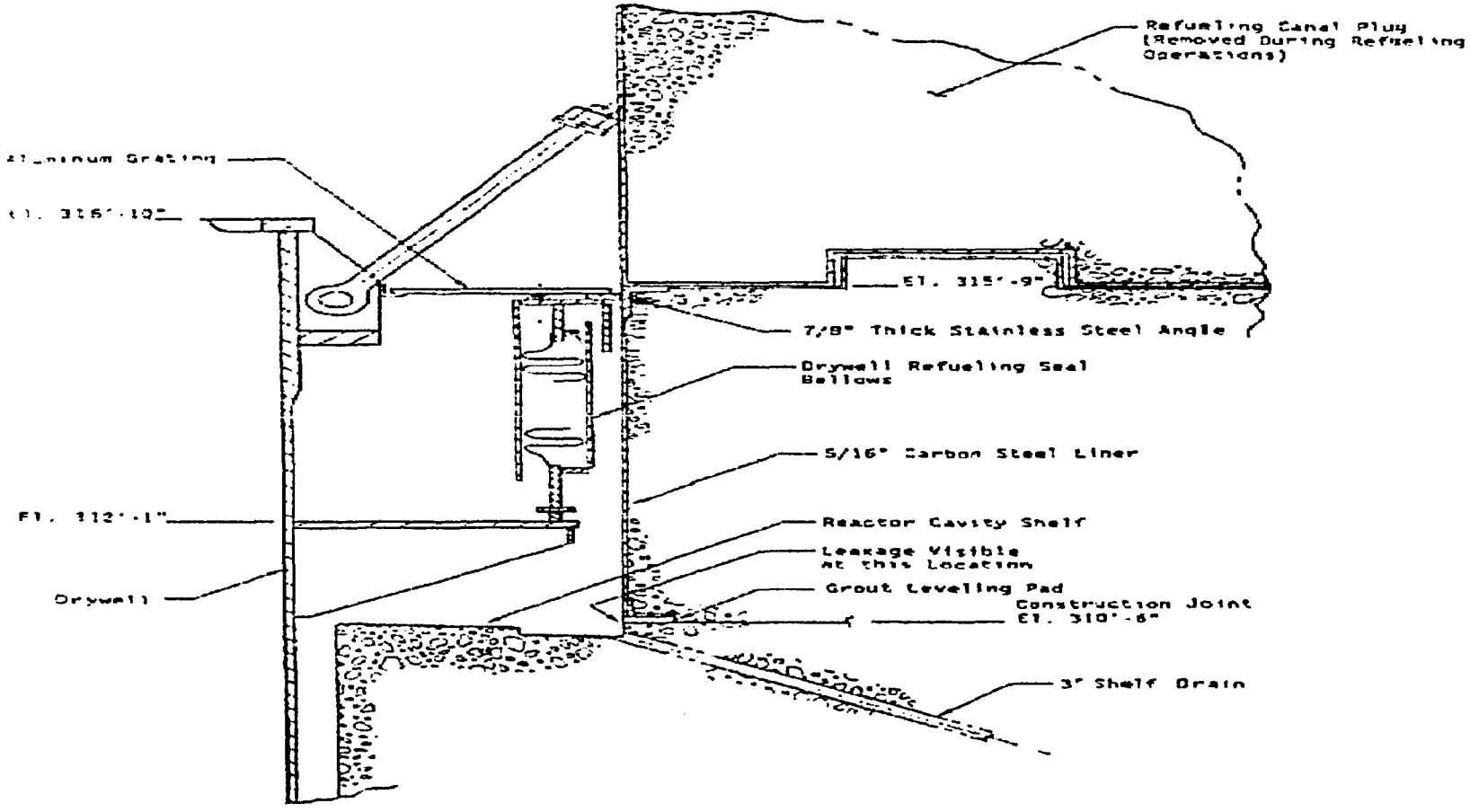
NMP1 CRD Stub Tubes

- CRD Stub Tubes
  - NRC approved use of roll repairs via SE dated March 25, 1987
  - ASME approval of Code Case N-730 pending for roll repair methodology
  - If, during PEO, a rolled stub tube re-leaks, one of following zero leakage repairs will be implemented:
    - Welded repair consistent with BWRVIP-58A as endorsed by NRC in RG 1.147
    - Variation of welded repair geometry specified in BWRVIP-58A, using Code Case N-606-1, subject to NRC approval
    - A future developed mechanical/welded repair method subject to NRC approval

NMP1 Drywell Design



NMP1 Drywell External Condition



NINE MILE POINT UNIT 1
REACTOR HEAD CAVITY REFUELING SEAL
AND SHELF AREA

FIGURE 3

NPR-007
Revision 0

Protective Coatings Monitoring & Maintenance

- NMPNS Program consistent with industry practice as documented in NEI Letter to NRC, "Qualified Coatings Assessments", dated 3/31/06
- NMPNS Program consistent with GALL Report, Rev 1, Section XI.S8
- Program not credited for Containment shell corrosion mitigation
- Program specifically credited and administered to ensure post-accident operability of the ECCS suction strainers

Plant Improvement Initiatives

CE Committed to an Ongoing Program of Station Improvement

- Implemented Noble Metal Chemical Addition and Hydrogen Water Chemistry at NMP1 (2000) and NMP2 (2000-2001)
- NMP2 Spent Fuel Pool to be re-racked eliminating use of Boraflex (2007)
- Implementing use of corrosion inhibitors in selected NMP1 and NMP2 Closed-Cycle Cooling Water Systems prior to entry into PEO
- NMP1 115kV Reserve Station Service Transformers and Switchyard Disconnect Switches replaced (2005)

Aging Management Programs

- 43 Aging Management Programs credited in ALRA
  - Includes 8 new programs
  - Aligned to GALL, Rev 1

License Renewal Commitments

- NMP Commitments managed and tracked via Nuclear Commitment Tracking System (NCTS)
- 54 LR Commitments
  - 41 NMP1 commitments implemented by 2 years prior to entry into PEO
  - 40 NMP2 implementation commitments to follow NMP1
- Priority for regulatory commitments is second only to safety consideration
- Implementation Plan and Schedule
- NMP senior management monitors implementation status weekly

Summary

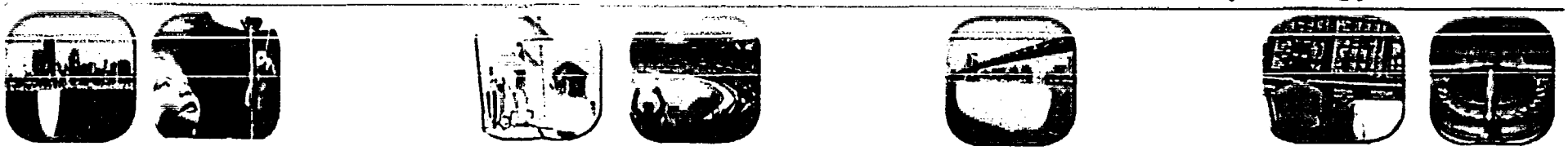
- Successful Recovery Project
  - Results of NRC's Audits and Inspection
  - Only 2 SER Open Items well on their way to being closed
- NMPNS manages plant aging issues effectively
- NMPNS will successfully implement its LR Commitments
- CE committed to Excellence and is, therefore, ever improving operation and reliability of NMPNS

Constellation Energy

Nine Mile Point License Renewal Units 1 and 2

Presentation to ACRS LR Subcommittee

The way energy **works.**™



Vertical Weld Repair Clamp

51

NINE MILE POINT NUCLEAR STATION
Units 1 and 2
License Renewal
Safety Evaluation Report

Staff Presentation to the ACRS
Tommy Le, Senior Project Manager, NRR
Dr. Kenneth Chang, Audit Team Leader, NRR
Robert Hsu, Assistant Audit Team Leader, NRR
Michael Modes, Lead Inspector, REGION I
April 5, 2006

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA submitted by letter dated May 26, 2004
- GE Boiling Water Reactors
  Unit 1: - Mark 1, GE BWR 2
  - 1850 Mwt, 615 Mwe
  - Operating License expires August 22, 2009
  Unit 2: - Mark 2, GE BWR 5
  - 3467 Mwt, 1144 Mwe (with 4.33% Power Uprate (EPU) in April, 1995)
  - Operating License expires October 31, 2026
  - Schedular Exemption issued October 8, 2002
- NMPNS located six miles northeast of Oswego, NY

Overview (continued)

- SER w/Open Items issued on March 3, 2006
  54 commitments:
  - Unit 1: 14
  - Unit 2: 13
  - Common: 27
  - Implementation: 2 years prior to Unit's PEO
  - Two Open Items and No Confirmatory Items
  - 3 license conditions

Section 2: Scoping and Screening Review

- NRR Scoping and Screening Methodology Audit
  - September 27 – October 10, 2004
- **Section 2.1** - Scoping and Screening Methodology
  - Staff audit identified issues resolved through RAI and amended application
    - 10 CFR 54.4(a)2 – NSR affecting SR
    - Evaluation of Plant Insulation

Section 2: Scoping and Screening Review (Continued)

- **Section 2.2,** Plant Level Scoping and RAI Results
  - 14 new systems were added, 3 previously included systems removed
  - New and Revised LR drawings identifying 10 CFR 50.54(a)(2) were provided
  - Amended LRA clearly identified SCC's within scope of LR and subject to AMR
  - Amended LRA now uses standard component types and component intended function consistent with SRP-LR and NEI-95-10 to identify SSCs in scope of LR and subject to AMR.
  - All issues were resolved in Amended LRA and the staff concludes that the applicant's methodology satisfies the rule pursuant to 10 CFR 54.4 (a)(1), (a)(2)

Section 2: Scoping and Screening Review (Continued)

Structures and Components	NMP 1	NMP 2
2.3 Mechanical Systems	**45** : 35 are BOP (28 Auxiliary and 7 Steam and Power Conversion Systems)	**61** : 47 are BOP (40 Auxiliary and 7 Steam and Power Conversion Systems)
2.4 Structures & Component Supports	Primary Cont. Structure Other Class 1 and in-scope Structures (11) Structural Commodities	Primary Cont. Structure Other Class 1 and in-scope Structures (13) Structural Commodities
2.5 Electrical /IC Systems & Commodities	Cables and Connectors Non-Segregated/ Sw-yard Bus Containment Electrical Penetrations Switchyard Components	Cables and Connectors Non-Segregated/ Sw-yard Bus Containment Electrical Penetrations Switchyard Components

Section 2: Scoping and Screening Summary

- The applicant's scoping methodology meets the requirements of 10 CFR Part 54
- Scoping and screening results included all SSCs within the scope of license renewal and subject to AMR

Region I
License Renewal Inspection

- 10 CFR 54.4 (a) (2) Inspection
- Aging Management Programs Implementation Inspection

- Conducted: February 14 - 18, February 28-March 4, and April 4 – 8, 2005
  - "(a)(2)" walk-down of 16 systems
  - Reviewed 22 programs
  - 15 open items within 5 programs

Region I - License Renewal Inspection (Continued)

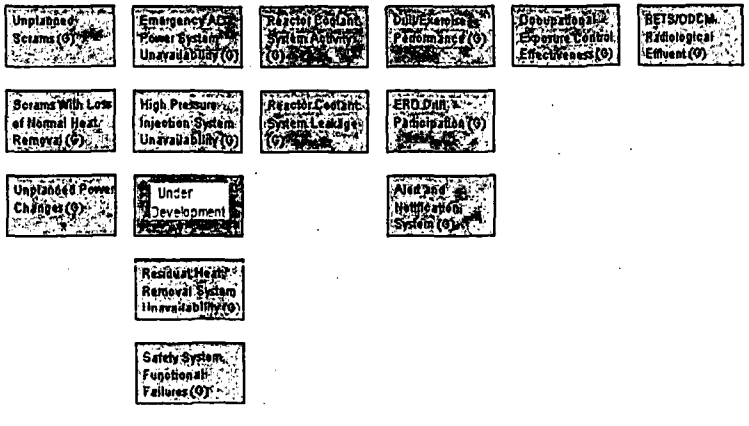
- 90 day recovery "stand down" implemented

- Conducted: December 12 – 15, 2005
  - reviewed resolution of previously-identified 15 open items

- Inspection Team concluded all open items were satisfactory resolved and closed out as presented in Inspection Report

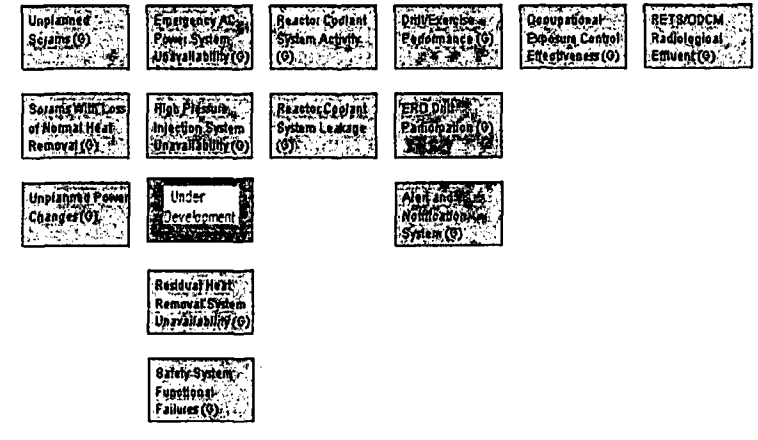
NMP **Unit 1**
4Q/2005 Performance Summary

Performance Indicators



NMP **Unit 2**
4Q/2005 Performance Summary

Performance Indicators



Section 3: Aging Management Review Results

- 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

Section 3: Aging Management Review Results (Continued)

- **DE / DCI Technical Review**
  - 7 Plants Specific AMPs and AMR Line Items
- **DLR Audit and Review**
  Original LRA
  Conducted: August 5 - 13, 2004, August 13 – 17, October 21 - 22, 2004, and October 25 – 26, 2004
- Amended LRA
  Conducted: September 19 - 24, and October 24 - 28, 2005
- Resulted in: - 5 new AMPS and
  - 23 new Commitments

Aging Management Programs -Bolting Integrity Program

- A new bolting integrity AMP was added as a result of the audit team's AMR review for closure bolting.
- Applicant committed to implement new AMP for both Units (U1 Comm. 33 and U2 Comm. 31)

Aging Management Programs -BWR Vessel Internals Program

- Consistent with enhancements
- Enhancements:
  - For example: 100% Inspection of Top Guide for Unit 1 (Commitment 13)

Aging Management Programs -Reactor Vessel Surveillance Program (RVSP)

- The RVSP manages loss of fracture toughness due to neutron irradiation embrittlement in the RV beltline materials.
- The RVSP is based on the integrated surveillance program criteria in BWRVIP-78 and BWRVIP-86.
- Enhancement: The RVSP will be enhanced to include conformance with the updated integrated surveillance program criteria in BWRVIP-116 (Commitment #22-NMP1, #20-NMP2).

Aging Management Programs -Unit 1 CRD Stub Tube Penetrations

- Originally, Unit 1 CRD stub tubes were repaired by roll/expansion techniques with an allowance for some amount of RCPB leakage. Plan to Implement Code case N-730 if Approved by NRC staff (Comm. 36 Unit 1)
- NMP will implement zero leakage permanent repair (Comm.36 U1):
  - Performed weld repair per BWRVIP-58A (Reg. Guide 1.147)
  - A variation of welded repair geometry and NRC approval of Code Case N-606-01
  - A future developed mechanical/welded repair method subject to NRC approval

Aging Management Programs -Unit 1 Emergency (Isolation) Condensers (ECs)

- The design of the emergency condensers features end bells welded to the EC shell that are not designed to be removed; therefore, eddy current testing, as recommended by GALL Report, of the tubing is not possible.
- During audit and review, applicant provided its basis for not performing eddy current testing and committed to implement a leakage test to detect small leak (U1. Comm. 29)

Aging Management Programs -Non-EQ Inaccessible Medium-Voltage Cables Program

- Originally, NMP claimed no inaccessible medium-voltage cables within scope of LR.
- The Audit Team identified at least one underground cable within scope for Unit 2. The applicant later identified a total of 18 cables requiring an AMP.
- The applicant developed a new AMP to be implemented prior to PEO (U2 Comm. 38)

Section 3: Aging Management Review Results (Continued)

Systems or Structures	NMP 1- Identified AMPs to manage Aging Effects	NMP 2- Identified AMPs to manage Aging Effects
3.1 Reactor Vessel, Internals, & Reactor Coolant System	15	14
3.2 Engineering safety Features	9	8
3.3 Auxiliary Systems	17	15
3.4 Steam & Power Conversion	9	6
3.5 Containment Structures & Supp	13	12
3.6 Electrical/ I&C Systems	6	6

Section 3.5, Containments, Structures and Component Supports

UNIT 1: Containments, Structures and Component Supports

- **OPEN ITEM:** NMP1 Drywell Liner Corrosion

Aging Management of In-Scope Inaccessible Concrete – Measured NMPNS Ground Water Parameters

	Acceptable Limit	NMP 1 & 2
pH	pH >5.5	6.79 – 7.83
Chlorides	Chlorides <500 ppm	7.7 – 49 ppm
Sulfates	Sulfates <1500 ppm	28 – 60 ppm

- Plant located adjacent to an inland lake with ground water testing performed once every six months
- Above data [from April & October, 2003 tests] indicate below grade environment is non-aggressive
- Because below grade environment is non-aggressive: No phosphate and phosphoric acid tests were performed

Section 4: Time-Limited Aging Analyses (TLAAs)

- **4.1** Identification of TLAAs
  - No TLAA-based Exemptions identified
- **4.2** Reactor Vessel Neutron Embrittlement
  - All analyses are Acceptable
- **4.3** Metal Fatigue
  - Committed to implement FatiguePro monitoring software (commitment #5 for U1 and 4 for U2)
- **4.4** Environmental Qualification of Electrical Equipment
  - EQ program together with other plant programs will adequately manage aging effect during PEO
- **4.5** Concrete Containment Tendon Prestress – N/A
- **4.6** Containment Liner Plate, Metal Containment and Penetration Fatigue Analysis
  - Adequate evaluation to demonstrate that fatigue usage not exceeded during PEO
  - Unit 1 FMP Torus Attached piping, Unit 1 Torus Monitoring Program,

Section 4: Time-Limited Aging Analyses - (TLAAs) (Continued)

- 4.7 Other Plant Specific TLAAs
  - TLAA evaluation for NMP2 Bioshield not based on NRC-approved methodology

OPEN ITEM 4.7B.1-1 in Staff SER w/OIs
- March 23, 2006, letter provides summary results of new (Reg. Guide 1.190 based) analysis
- Withdrew Bioshield TLAA 4.7B.1

Reactor Vessel (RV) Upper Shelf Energy (USE) - Analysis Summary for **NMP1**

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	**Acceptable** Y/N
NMP1 Lower Shell Plate (Heat No. G-8-1)	Percent Drop < 29.5 % Drop in the USE ft-lb value*	19.2 Percent Drop in USE ft-lb	**Yes** TLAA satisfied 54.21(c)(1)(ii)
NMP1 Upper Shell Plate (Heat No. G-307-4)	Percent Drop < 29.5 % Drop in the USE ft-lb value*	24.9 Percent Drop in USE ft-lb	**Yes** TLAA satisfied 54.21(c)(1)(ii)
NMP1 Circumferential Weld (SAW) Heat No. 1248	Projected USE > 50 ft-lbs	64 ft-lbs	**Yes** TLAA satisfied 54.21(c)(1)(ii)

*Acceptance criteria for beltline plates and welds established by elastic-plastic fracture mechanics analysis in BWRVIP-74-A discussed in SER pages 4-10 to 4-11 and 4-15

Reactor Vessel (RV) Upper Shelf Energy (USE) - Analysis Summary for **NMP2**

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	**Acceptable** Y/N
NMP2 Number 2 Shell Plate (Heat No. C3147-1)	Projected USE > 50 ft-lbs at EOLE	62.3 ft-lbs	**Yes** TLAA satisfied 54.21(c)(1)(ii)
NMP2 Number 1 Shell Plate (Heat No. C3147-2)	Projected USE > 50 ft-lbs at EOLE	76.5 ft-lbs	**Yes** TLAA satisfied 54.21(c)(1)(ii)
NMP2 Axial Weld (SAW) (Heat No. 5P5657/0931)	Projected USE > 50 ft-lbs at EOLE	74 ft-lbs	**Yes** TLAA satisfied 54.21(c)(1)(ii)

RV Circumferential Weld Relief / RV Axial Weld Probability of Failure Analyses

RV Material	TLAA Basis	Acceptance Criterion (° F)	NMP1 Value (° F)	NMP2 Value (° F)
Limiting Circ. Weld	BWRVIP-05 Mean RT_{ndt} Value in ° F	<113.2	22.3 (NMP) 22.4 (Staff)	N/A*
Limiting Axial Weld	BWRVIP-05 Mean RT_{ndt} Value in ° F	<114.0	31.3 (NMP) 31.0 (Staff)	-5.0 (NMP) -5.0 (Staff)

- *NMP2 has not submitted a relief request for the elimination of circumferential weld inspections for the remainder of its 40-year licensed operating period.
- TLAAs for the Circ. Weld and Axial Weld Mean RTndt values were in all cases determined to be acceptable under 10 CFR 54.21(c)(1)(i) or (ii)

TLAAs Summary

- TLAAs
  - 10 CFR 54.3: TLAA list adequate, as amended
  - 10 CFR 54.21(c)(1)(i): analyses remain valid for PEO, (ii): analyses projected to the end of PEO, and (iii): aging effects will be adequately managed for PEO
  - 10 CFR 54.21(d): Sufficient supplements to FSAR
  - 10 CFR 54.21(c)(2): No plant specific exemptions

Conclusions

- The staff has concluded that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with CLB, and that any changes made to the NMPNS CLB in order to comply with 10 CFR 54.29(a) are in accord with the Act and Commission's regulations.