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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

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ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

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NUCLEAR REGULATORY COMMISSION

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

<u>NRC STAFF PRESENT:</u>

CAYETANO SANTOS Designated Federal Official
JAKE ZIMMERMAN
DAN MERZKE
PATRICIA LOUGHEED
DAVE POTTER
MICHAEL ALEKSEY
PETER WEN
BARRY ELLIOTT
HANSRAJ ASHAR
JAMES MEDOFF
DR. KEN CHANG
DR. K.T. KUO

<u>MONTICELLO REPRESENTATIVES PRESENT:</u>

PATRICK BURKE
JOHN GRUBB
JOEL PAIRITZ
SHERRY BERNHOFT
JIM ROOTES
RON SIEPEL
STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Tuesday, May 30, 2006
Work Order No.:	NRC-1057 Pages 1-114

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

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Plant License Renewal Subcommittee

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

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NUCLEAR REGULATORY COMMISSION

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

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ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

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Docket Number:	(not applicable)
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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE

MEETING

+ + + + +

ROCKVILLE, MARYLAND

TUESDAY

MAY 30, 2006

The Subcommittee met in Room 2TB3 at Two White Flint North, 14555 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Mario V. Bonaca, Subcommittee Chair, presiding.

MEMBERS PRESENT:

MARIO V. BONACA Chairman

J. SAM ARMIJO

WILLIAM J. SHACK

JOHN D. SIEBER

GRAHAM B. WALLIS

OTTO MAYNARD

NRC STAFF PRESENT:

CAYETANO SANTOS Designated Federal Official

JAKE ZIMMERMAN

DAN MERZKE

PATRICIA LOUGHEED

DAVE POTTER

MICHAEL ALEKSEY

PETER WEN

BARRY ELLIOTT

HANSRAJ ASHAR

JAMES MEDOFF

DR. KEN CHANG

DR. K.T. KUO

MONTICELLO REPRESENTATIVES PRESENT:

PATRICK BURKE

JOHN GRUBB

JOEL PAIRITZ

SHERRY BERNHOFT

JIM ROOTES

RON SIEPEL

STEVE HAMMER

A-G-E-N-D-A

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

1.31 p.m.

CHAIRMAN BONACA: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Jack Sieber, Bill Shack, Graham Wallis, Sam Armijo and Otto Maynard.

Cayetano Santos of the ACRS Staff is a Designated Federal Official for this meeting.

The purpose of the meeting is to discuss the license renewal application for the Monticello Nuclear Generating Plant. We will hear presentations from the NRC's Office of Nuclear Reactor Regulation and representatives of the Nuclear Management Company.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal*

Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We will now proceed with the meeting. And I call upon Mr. Jake Zimmerman to begin the meeting.

MR. ZIMMERMAN: Thank you, Dr. Bonaca.

Good afternoon. My name is Jake Zimmerman. I'm the Branch Chief in License Renewal Branch B, in the Division of License Renewal.

With me today is Dr. Ken Chang, who is the Branch Chief for License Renewal Branch C, whose responsibility is the on-site audits of the aging management programs and the aging management reviews and also the time limit and aging analysis.

Behind me also is Dr. P.T. Kuo, our Deputy Director for the Division of License Renewal,

who you all are familiar with.

The Staff has conducted a very detailed and thorough review of the Monticello Nuclear Generating Plant license renewal application which was submitted in March of 2005. Mr. Dan Merzke, here to my right, is the Project Manager for this review. He will lead the Staff's presentation this afternoon on the draft safety evaluation report.

In addition we have Ms. Patricia Lougheed who is our team leader for the Region III inspections that were conducted at Monticello Nuclear Generating Plant.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions.

The Staff felt that the Monticello Nuclear Generating Plant application was of very good quality. This resulted in the issuance of only a 113 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out of these reviews in the past. We believe part of that reduction is as a result of the Generic Aging Lessons Learned Report. This application was submitted using the draft GALL Report that was issued back in January of 2005,

however it was reconciled with the September 2005 version of the GALL Report. In fact, it resulted in a 95 percent consistency between their application and the revised GALL. So I think it was a good application. The GALL certainly helped with the review providing a roadmap.

In addition, the Staff at Monticello provided excellent support for our on-site audits, the inspections that were conducted and also the headquarters reviews through the conference calls and numerous meetings that we had.

Because there are no open items, the Staff has requested that we accelerate the schedule to complete this review in 20 months versus our standard 22 months. That's been the practice over the last several license renewal applications, and we're working with ACRS Staff to set up the next meeting.

And with that, I'd like to turn it over to Pat Burke, who is the Manager of this project to begin the applicant's presentation.

MR. BURKE: Thank you, Jake.

And thank you members of the ACRS Subcommittee for allowing Monticello to present this presentation in support of the Staff in this meeting

today.

What I'd like to do is start off by giving a brief introduction of the team and the members that we have here today to help answer any questions you may have.

Now we have on my left here a Mr. John Grubb, who our Director of Engineer.

We have Ms. Sherry Bernhoft, who is the Director of Fleet Project Management in the audience.

Again, I am Patrick Burke, the Manager of Projects.

Joel Pairitz is our License Renewal Project Manager.

Ray Dennis is our civil lead.

Ron Spiepel is our electrical lead.

Jim Rootes is our programs lead.

Michael Aleksey we have as our TLAA support.

Dave Potter is our engineering supervisor of inspections and materials.

And Steve Hammer is a principal engineer on the project.

We also have with us today our sister plant, Palisades from the Nuclear Management Company

observing and gaining any lessons learned during this presentation today.

What we'd like to talk about today is the agenda. We will start with having John Grubb go over a brief description of the Monticello Nuclear Generating Plant.

And I'll talk a little bit about the operating history and some highlights. I'll talk a little bit about the project application and background. I'll discuss the methodology. And as Jake mentioned, we'll talk a little bit about the application of the GALL to Monticello's application.

At that point I'll turn it over to Joe, our Project Manager to go over a couple of industry topics such as drywell shell corrosion shroud cracking, steam dryer. And then we'll conclude with a short discussion on commitment process.

At this point I'd like to turn it over to Mr. John Grubb.

MR. GRUBB: All right. Thank you, Pat. And again, thanks to the Committee.

A brief description of the Monticello plant. The plant is located, it's on the banks of the Mississippi River. It's roughly 30 miles northwest of Minneapolis. It's approximately 2100

acres of land that's owned by Xcel Energy.

The plant is a single unit GE BWR 3. We do have a Mark I containment.

MEMBER WALLIS: One question about this.

MR. GRUBB: Yes, sir.

MEMBER WALLIS: How far do the suburbs of Minneapolis extend the direction of the plant?

MR. GRUBB: The closest suburb actual Minneapolis suburb to the plant is the Maple Grove suburb, and it's about 18 to 20 miles.

MEMBER WALLIS: Okay. Thank you.

MR. GRUBB: Our current license thermal power is 17075 megawatts thermal, approximately 600 megawatts electric.

The plant is owned by Northern States Power Company, which is a subsidiary of Xcel Energy.

The plant is operated by the Nuclear Management Company.

And we have an on-site staff of approximately 420.

Just a quick aerial view of the station. The Mississippi River, which is ultimate heat sink. Intake structure here. Turbine building. Reactor building. Cooling towers and discharge canal here. Return to the river up in the upper left. The

subyard is here. It's a pretty small, relatively compact site.

Next.

What you'll see in this slide is that Monticello has historically been and continues to be a very reliable plant. Our current unit capability factor is rated at 93 percent. Our INPO performance index is at 100 percent. We are greater than 1500 days since our last scram from power. Our current operating cycle, we've been online for greater than 400 days. We currently have no equipment issues that are threatening unit availability.

MEMBER SHACK: What's your fuel like?

MR. GRUBB: We are on a two year fuel cycle.

The performance indicators are all green. And we have no findings that have been greater than green.

MEMBER SIEBER: I have a question about the inspection findings.

MR. GRUBB: Yes, sir.

MEMBER SIEBER: I looked through all of your inspection reports for the last couple of years, and including the summary of the findings. And they were all green or less. And I noticed a

lot of areas didn't have any findings at all, which is actually a good thing.

On the other hand, if I review all those findings which resulted in on-sited violations, I think that you might be able to pick out a trend. And I was wondering if you have done that and see a trend or a problem area in your findings?

MR. GRUBB: Well, I wouldn't say I see a problem area. What Monticello has been going through over the last several years is we focused on the programs area specifically and we've done a lot of reconstitution. And a lot of time focusing, doing assessments in the programs area. So we have a number of things that have come up in the programs; Appendix R, fire protection, EQ, some of those areas that we have focused on. But we've been doing that because we recognize that maybe we hadn't been at the top of the industry with respect to how we treated programs historically.

MEMBER SIEBER: Another thing that I noticed was several operator errors that occurred during surveillance testing. Does your staff have a pretty good size turnover at this time? It's an older plant and older plants often have a staff that grew up with the plant.

MR. GRUBB: Yes. There has not been a lot of turnover in the operations area specifically. We have been trying to bring groups of new license candidates and new operator candidates over the last several years. We hired ten last year.

As far as the human performance, we do recognize that. There is two initiatives at the site level that we're going after to try to address that.

What the station is is we have six focus areas. And the way we treat those is if we do nothing else as a station, those six areas are going to get a lot of attention. Two of those, one is operations leadership which is making sure the Ops department is leading the station and the operators are taking responsibilities. The second one is procedure use and adherence. So we have recognized that trend and we are focusing on those two areas.

MEMBER SIEBER: And how would you describe compared to other plants the material condition of Monticello?

MR. GRUBB: I guess I don't have a good picture of the rest of the plants. Our material condition is very good. We're in pretty good shape. The plant has historically been maintained very

well. What you'll see at Monticello and the people that come to Monticello, the craft and the mechanics and so forth that maintain the equipment take a tremendous amount of ownership. And as a result of that, our equipment performance and our equipment is in very good condition.

MEMBER SIEBER: I would caution that even though Minnesota is a great place, you might not want to isolate yourself from your brethren in the industry and get out and see what the best plants look like and make yours just like it.

MR. GRUBB: We agree.

MEMBER SIEBER: Okay. Thanks.

MR. GRUBB: All right. Pat, back to you.

MR. BURKE: All right. I'd like to start my discussion with a little bit on the operating history and highlights, some background, Monticello's construction. The permit was issued in 1967. We obtained our operating license in September of 1970. That means that 40 years later in September of 2010, our 40 year license would expire. And as Jake mentioned earlier, we did submit our license renewal application in March 16th of 2005.

These next couple of slides I'll talk a little bit about the operating history, and this will go to the point of material condition which we just talked about.

In 1984 we replaced all the resurg piping with a low carbon stainless steel resistent to intergranular stress corrosion cracking. The small bar piping was a 304L material. The large bar piping was a 316 NG material. During that project we replaced risers, supply headers, suction piping and safe-ends.

We made some additional improvements by reducing the number of welds and doing some induction heating, stress improvement and electropolishing was applied to the new pipe.

In 1986 we replaced spray safe-ends with intergranular stress corrosion cracking resistant material also.

In 1989 we implemented the hydrogen water chemistry. We were one of the early plants in implementing that. We implement the moderate hydrogen water chemistry for protection of the vessel internals.

MEMBER SHACK: And you're still doing that rather than noble metal?

MR. BURKE: That's correct. We are still with moderate hydrogen water chemistry. We have been evaluating noble metals. We've been kind of a slow deliberate approach to reviewing that. We've had very, very good fuel reliability. So we're kind of going slowly into noble metals.

MEMBER ARMIJO: Have you been adding any zinc for dose retrieval?

MR. BURKE: Yes, we have. We inject depleted zinc.

MEMBER SHACK: This is probably getting ahead because you're going to tell us about core strength, but what's the condition of your core shroud jus as a sample internal that's seen a lot of cracking in other plants?

MR. BURKE: I think I'll defer that Mr. Dave Potter.

MR. POTTER: I am Dave Potter from the Monticello plant.

The condition of our shroud is actually better than most in the industry. I wouldn't say it's the best. Our most cracked weld is the H3 weld which had 27 percent indication of our last inspection. But we had three-quarters of that weld basically covered in our last inspection. So in

relative terms our shroud is very good.

MR. BURKE: And we will be giving more information in a minute also.

In 1997 we did replace the emergency core cooling system suction strainers. And we increased the surface area of those strainers for debris loading.

In 1998 we did initiate a power uprate. We increased our power level from 1670 megawatters thermal up to 1775 megawatts thermal, which was a 6.3 percent increase.

As part of the license renewal effort, we did implement six SAMAs, which did significantly reduce our overall plant risk.

MEMBER SHACK: Now those are the six SAMAs that were identified in your environmental impact statement as having a favorable cost risk?

MR. BURKE: Yes, sir. That is correct.

MEMBER SHACK: That's all six, including the manual RCIC which reduced your CDF but upped your risk?

MR. BURKE: That is correct.

MEMBER SHACK: Okay. Well, if one of my colleagues was here, he'd ask you about that. But we'll let that one pass.

CHAIRMAN BONACA: He's not here.

I would like to know, however, what is the CDF for this plant?

MR. BURKE: The core damage frequency before the six SAMAs was 4.37 ten to the minus fifth. And the after implementation --

CHAIRMAN BONACA: Internal events or total?

MR. BURKE: Total events.

CHAIRMAN BONACA: Internal events?

MR. BURKE: Internal, that's right.

And after the implementation of this was changed to 5.99 times ten to the minus six per year.

MEMBER SHACK: That was a question I was going to have for the Staff. You know, reading through here this was the first environmental impact where I came to the SAMAs and they actually, you know, they had a bunch of favorable ones. And the fire truck one was a real bargain. You know, you haul the fire truck and hook it up.

What is the criteria for when -- why did we ask these people to do these SAMA analysis? Is there some criterion that they would meet that they would have to do them or is it just something they look at? You know, they obviously choose to

implement a number of the SAMAs. And I just wondered in general what do we do with the SAMA analysis after they do it?

You can come up with that later or answer now?

MR. KUO: Yes. P.T. Kuo, License Renewal.

We generally perform the SAMA analysis and if we see there is a cost benefit area that the applicant can improve, then we make the recommendations. And we send this recommendations to them that these are the cost beneficial actions that they have to take.

And then later on --

MEMBER SHACK: So they don't have to take them, though?

MR. KUO: They don't have to take them.

MEMBER SHACK: They could take them?

MR. KUO: But based on our SAMA analysis we identify, if we identified any actions that we believe is beneficial, we'll let them know.

MEMBER SIEBER: Before you move forward, I'd like to go back to your 6.3 percent power uprate. Do you have additional margin in your plant where you could perform another uprate in power?

MR. BURKE: We've done some studies, some evaluation on that. There would be significant cost. If we decided to do another power uprate, it would be a significant cost to replace the equipment.

MEMBER SIEBER: Like the turbine?

MR. BURKE: Like the turbine, generator rewinds, transformers, feed pumps.

I think the answer to your question is there is probably not a lot of margin above and beyond for another power uprate. We have margin where we're at.

MEMBER SIEBER: Okay. Thanks.

MR. BURKE: Now looking out into the future, we have a number of future lifecycle management projects that are in progress and being implemented, such as replacement of feedwater heaters, recirc pump motors and rotating pump assemblies. We've done the 11 pump last outage and we plan to do the 12 pump this outage the service water pump replacements and transformers and generator rewinds.

The next couple of slides I would like to talk a little bit about the project. This slide here what I'd like to talk about is how we selected

the people for the project and how we made sure we had the right people for the project.

Now, we initiated the project through an interview process for site employees. We selected a core team. They're NMC employees that were from the site. Four of them had SROs or SRO certifications and all of them were very experienced and multidisciplined.

We supplemented that core team with license renewal experienced contractors. Again, the majority of those contractors were on-site performing that work. We did retain the majority of that team during the audits and inspections. So we had the same people that prepared the application supporting the audits and inspections.

We contracted with General Electric to perform the reactor pressure vessel and internal time-limited aging analysis and aging management reviews.

And we also did engage the plant and the site staff in review of aging management review documents and aging management program documents.

MEMBER SHACK: The one thing that struck me as extraordinary, though, in the TLAA for the core shroud, the first estimate of the shroud

fluence peak was 3 times 10 to the 20, and then it got changed to 3.8 times 10 to the 21. Now that's a factor of 14 and it was a change in methodology. I'm a little surprised to see that kind of a change. Is there some explanation for what went on there?

MR. BURKE: Yes. I'd like to defer that to Michael Aleksey.

MR. ALEKSEY: My name is Michael Aleksey.

I'd like you to rephrase that question, please? I didn't hear the first part of it.

MEMBER SHACK: In the initial license renewal application it says the peak shroud fluence was 3 times 10 to the 20 neutrons per square centimeter greater than 10 1eV.

MR. ALEKSEY: Yes.

MEMBER SHACK: Then it got changed to 3.8 times 10 to the 21. I mean it's a factor of 14.

MR. ALEKSEY: Well, the original analysis was based on Reg. Guide 1.99 and the original capsule that was pulled in 1984 thereabouts, we went to the Reg. Guide 1.190 evaluation and used the typical factors to bump that up by 30 percent at certain areas and stuff like that, and came up with the results that we got.

I don't think that that's unusual in terms of --

MEMBER SHACK: It's not unusual? A factor of 14? I mean, you know from a case 3 times 10 to the minus 20 you're hardly seeing any influence of irradiation on stainless steel to 3 times 10 to the 21; it's, you know, a big time change. It's embrittlement, it's high crack growth rates without your hydrogen water chemistry.

I mean, normally I hear the Staff beating up people over 10 percent changes in fluence and a factor of 14 just seems very large.

Barry is going to enlighten me.

MR. ELLIOTT: Barry Elliott, NRC.

I'd just like to talk to them for a second.

I believe in their application, and I'm making some assumptions, the original applications likes the fluence is calculated for either 1775 megawatts or 1680 or something like that. When they did the recalculation for these, it looks like they used 1830 megawatts or 1880 megawatts for cycle 23 through the end of the license renewal period. So that would account for some of the large increase. In other words --

MEMBER SHACK: But a factor of 14?

MR. ELLIOTT: I'm just saying that they went from 1660 or something like that all the way up to 1880 megawatt thermal. So that increases it quite a bit.

And then they used a new GE methodology, which they hadn't used before.

So all this stuff added in, I mean this is what you did. So, I mean, I'm just reading the application. You tell me is that what you did?

MR. ALEKSEY: This is Mike Aleksey.

Yes, we did. Originally it was based on 1670 and the Reg. Guide 1.190 evaluation it was based on 1775 up through cycle 22 and then we increased that to 1880 for cycle 23 on, which did provide a significant conservatism. And the reason we did that is because we had performed other analyses at that level before and we thought it was a prudent thing to do.

MEMBER SHACK: Okay. Well, I mean since you can live with 3 times 10 to the 21, you know and that sounds like the typical value I have for end-of-life for a core shroud. You know, when I saw the 3 times 10 to the 20 in the original application, I wondered how much water you had

between your core and your shroud, and it seemed extremely low. The 3 times 10 to the 21 is about where I expected it to be. I still don't understand why it's so different, but obviously you can live with it. And,as I say, it's a value that I find plausible.

CHAIRMAN BONACA: Okay. Next slide, please.

This slide talks a little about how we were engaged in the industry during the development of license renewal application. We attended many of the working groups. We did participate in the GALL draft revision 1 review and comments through NEI.

And we participated in our sister NMC plants during their audits and inspections to gain lessons learned.

We supported numerous license renewal peer reviews throughout the industry. We also hosted our own peer review where we did have seven external peers on that team.

And then we did review many industry RAIs and in detail we reviewed the Nine Mile, Point Beach and Dresden/Quad's RAIs.

These next couple of slides we'll talk a little bit about the methodology. Most of these

bullets that I'll talk about now is where we added additional detail into the application that you might not always see. For example, we identified system functions and tied those to the different criterion for the different scoping to help better describe why the system wasn't scoped.

We paid a lot of attention to our boundary drawings and included boundary flags and multicolored boundary drawings.

We used plant documentation to identify our scoping components. Use DBDs and did extensive plant walkdowns.

We created a number of technical reports including those for criterion 2, nonsafety effecting safety and also for the regulated events.

And then we did use the spaces approach for our criterion 2, and that was incorporated into the application.

MEMBER MAYNARD: I did have a question here. Taking about your scoping, your boundary drawings and everything. And yet in the inspection report I noticed that the inspectors found a number of items or systems where the boundary needed to be changed or something needed to brought into scope, or whatever. I'd like to get your perspective on

that. Because it seemed like there's a number -- I don't know if the inspectors were really picky or whether you guys had missed these or what.

CHAIRMAN BONACA: No. We didn't have some. There were some areas in the drawings, but I think overall we felt that our drawings were pretty accurate as boundary drawings typically go in the industry.

MR. PAIRITZ: I am Joe Pairitz, the Project Manager.

Some of the cases, too, occurred where a color suddenly stopped and there wasn't an explanation for why that was. And basically it was that it went through a wall so it was no longer in scope for criterion 2. And we had quite a few instances where we had to go walk that down with NRC inspectors to look at that. And we're doing it over again, I would draw the wall in the drawing and make it easier. But that was the cause for a good number of those questions.

MEMBER SIEBER: You had other situations where the line that started off on 1 PNID as a colored line in scope, the adjoining PNID didn't have a colored line in scope. So it ended at the boundary of the drawing as opposed to some physical

boundary.

MR. PAIRITZ: This is Joe Pairitz again.

That's correct. There were several instances where the continuation went to the next drawing, it didn't color it properly, and we did correct those.

MEMBER SIEBER: Well, I read the same inspection reports. And it just seemed like there was a lot of them, relatively speaking.

My question to you would be now that the inspection's over with, which is vertical slices and not comprehensive, how confident are you that you have captured all that should be in scope and identified that on your plant drawings?

MR. PAIRITZ: Joe Pairitz again.

We did capture those instances in our corrective action program. And part of that was looking at other drawings to see the extent of condition basically. And we're confident right now that we have corrected those problems.

MEMBER SIEBER: When you did that, did you find additional problems that wasn't found by NRC inspectors?

MR. PAIRITZ: Off the top of my head right now, I don't know for sure. There might have

been a couple, but basically no. And we spent a lot of times on the drawings so we we're pretty confident that they were right to begin with. They did find a few instances, and in our works to correct that I think we might have found a couple more. But it wasn't a significant number.

And these things were in scope. It was just the drawing didn't get colored properly.

MEMBER SIEBER: Yes. I gathered that from the write-up.

CHAIRMAN BONACA: Well, some items were also brought into scope, so there was some of both.

MR. PAIRITZ: Right.

CHAIRMAN BONACA: Since we're talking inspections, I had a question about the corrosion that the inspectors found on the conductor termination logs of the fire diesel pump. And I'm sure you have a surveillance program for that pump. And so it was disturbing to read it because in license renewal you are going to have a program dealing with this fire pump which is an extension of your existing program. And when I have to wait for an inspector to find it, it troubles me and I wondered about your view on that issue.

CHAIRMAN BONACA: Could I defer that to

Ron? He was involved with that inspection activity.

MR. SIEPEL: Right. My name is Ron Siepel. I'm the electrical lead.

And if I understand the question right is you had a question on the corrosion of the wire that was in the diesel generator panel, is that the question?

CHAIRMAN BONACA: Fire diesel -- fire pump.

MR. SIEPEL: Okay. The diesel fire pump panel, that panel had been identified on a previous CAP or condition action request that was in the process of replacement and it just hadn't been replaced to date. And if it hasn't been replaced now, it'll be replaced shortly. But that had been previously identified out there under our program, and it was in the process of being replaced.

CHAIRMAN BONACA: It wasn't identified before? Wasn't clear from the inspections?

MEMBER SHACK: I was just curious. The Staff SER sort of credits your computerized history and maintenance planning system with helping in the scoping, and yet it's not credited at all in your license renewal application. You actually use this thing or is it just sort of sitting around.

MR. BURKE: This is Pat.

The CHAMPS database was used as a starting point for the scoping process. That was downloaded into a licensed renewal database called ALEX.

The CHAMPS database is used more for work management, so you have many of the active components in there. And that was a starting point. By taking that and using that as a starting point and then adding all of the passive components, therefore you would up with a complete ALEX database for scoping and screening to take you through the process methodically on a databased driven platform.

The next slide I'd like to talk a little bit about the ageing management review. A couple of other details that we added that I think help tell a better story in the application was adding mechanism for the aging effects.

MEMBER SIEBER: Let me ask one quick question before we leave scoping. Is your condensate storage tank in scope? I know piping and anchors and bolts and housings are. But the tank doesn't seem to be. Do you know?

CHAIRMAN BONACA: I don't know off the top of my head.

MR. PAIRITZ: This is Joe Pairitz.

The piping leading up to the tank is in scope. The tanks themselves, I guess I'll have Ray check on that, but I think the tanks themselves are not in scope.

CHAIRMAN BONACA: Individual --

MEMBER SIEBER: Yes, that's the way to be. And I was wondering, you know, if all the other stuff is in scope, why isn't the tank is in scope? And if the tank would fail, can you still accomplish what you're supposed to accomplish?

MR. BURKE: Yes. I'll answer one of the questions, the CSTs being in scope or not. We do not credit the condensate storage tank for any design basis accident so they are not considered safety related.

The piping going up to the tanks, I believe and correct me if I'm wrong, Joe, is in there from a nonsafety effecting safety standpoint. Because they do lead in --

MEMBER SIEBER: Criterion 1?

MR. BURKE: Yes, that's correct. Criterion 2. So that's why we terminated at the tank.

And I guess Ray agrees with that. Okay.

MEMBER SIEBER: I will have to think about it? Thank you.

CHAIRMAN BONACA: Sure.

And also for the aging management reviews we did numerous walkdowns to identify materials and environments.

As for the aging management programs, we wound up with 36 aging management programs. And we did include the ten elements from GALL in the application describing each program.

And lastly, I'd like to talk about the application of GALL, and this is consistent with what Jake started with, is we did have GALL reconciliation to the Rev 0. That showed us to be 75 percent consistent with GALL. After we submitted it we performed a precedents review, which brought us up to 95 percent consistent with GALL. And we believe that that high consistency with GALL increased the efficiency of the audit and inspection process.

At this point I'd like to turn it over to Joe to go over the industry topics.

MR. PAIRITZ: Thank you, Pat.

Again, I'm Joe Pairitz. I'm the license renewal Project Manager and also the mechanical

lead.

I'm going to talk about three industry topics, the first being drywell shell corrosion, second being the shroud cracking and thirdly the steam dryer.

Starting with the drywell shell corrosion, I'll give a little fresher on the Mark I primary containment. This is a cut away view of the reactor building. You have the reactor here in the center, the drywell is the inverted light bulb shaped liner right here. We have the vent pipes going down to the suppression chamber, otherwise known as the Torus.

We will concentrating on the refueling bellows located at the top here. The air gap region between the drywell shell and the surrounding concrete and also the sand pocket region here towards the bottom.

While the reactor cavity is flooded, and that would be this area here. This is the spent fuel pool over here. While the reactor cavity is flooded for refueling activities, Monticello has multiple design features for vent leakage from entering or accumulating in the air gap region and in the sand pocket regions. There are three separate drain

paths that exist to channel leakage away from these areas in question.

We have a seal barrier over the sand pocket region and we also have a flow switch that would alert operators to any leakage from the bellows.

MEMBER ARMIJO: This is Sam Armijo.

I have a quick question: Is this unique for this particular BWR 3? Are these features added that other --

MR. PAIRITZ: Some of the BWR 3s have them and some don't. I think it might be related to who the AE was on the project. I'm not sure of that.

MEMBER ARMIJO: Okay.

MR. PAIRITZ: We'll move into the refueling bellows area, otherwise known to some people are a refueling seal.

We have the reactor pressure vessel shell over here on this side. The first set of bellows we have are the reactor vessel to drywell bellows. We move over, we have the drywell shell right here. We have the second set of bellows that are between the drywell shell and the reactor building concrete. These bellows are in scope for license renewal. If these bellows were to leak, the

first barrier we have to protect the air gap, which is down here, would be this trough or channel that's down here that's supposed to catch any leakage that would come from that bellows.

And then you have an 8 inch pipe here that eventually reduces to a 4 inch pipe and goes to rad waste. That line also has a flow switch on it. Instead of 3 gallons per minute, that gives an alarm in the control room. So if they've got a leak here that's 3 gallons per minute or greater, it would alarm in the control room.

These bellows and center spool plate have been inspected in the past with no significant degradation noted at that time. That was in the late '80s.

I think we'll go on to the next slide.

Continuing into the air gap region here, we have a 4 inch drain pipe here. There's actually 4 of these, 4 four inch drain pipes.

MEMBER MAYNARD: I'm sorry.

MR. PAIRITZ: Yes.

MEMBER MAYNARD: Go back. You say a setpoint at 3 gallons per minute. Now wouldn't typically you'd expect to see none?

MR. PAIRITZ: We expect to see none,

correct.

MEMBER MAYNARD: Okay. I'm not familiar with it, but 3 gallons a minute --

MEMBER SHACK: That's a lot of water.

MEMBER MAYNARD: You know, 2 gallons a minute wouldn't set the alarm off and that's seems to me like it'd be quite a bit of water.

MR. PAIRITZ: Well, it is set at three. I can't address the design basis for the three right now. I think basically it was there to address gross failure of the bellows. But if we had any leakage, I can show you were that would be detected.

MEMBER MAYNARD: Okay. So any leakage would be detected?

MR. PAIRITZ: Yes. And I'll think we'll get to that when we talk about this picture.

MEMBER MAYNARD: Okay. All right.

MR. PAIRITZ: Here we have the air gap which extends up towards the bellows. We have 4 four inch drain pipes that drain this air gap region if water were to get in that region. We have 18 gauge galvanized sheet metal cover the sand pocket region that's sealed to the drywell shell and sealed to the surrounding concrete. So any water that might accumulate on this sheet metal cover should be

drained away by the 4 four inch drain lines.

Now these drain lines come into the Torus room, some people might know it as reactor building basement. They're open. They come down to floor level. They're open. You're going to have water on the floor if there's any leakage in this air gap region because they empty. They don't go to rad waste, they go right on the floor into the reactor building.

MEMBER WALLIS: You are concerned about corrosion. And what you need for corrosion is oxygen, presumably. That's from the air gap.

MR. PAIRITZ: Correct.

MEMBER WALLIS: And you need some moisture. But you don't need a flow of water. And the drains take away a flow of water, but a sufficient humidity in there with very small amount of liquid on the surface could lead to corrosion.

I'm not quite sure why drain prevents corrosion. You've got to really control the humidity, don't you?

MR. PAIRITZ: Well, when the linear was originally manufactured it was painted with a primer. So it does have some protection on it from that.

The humidity you get in there, I mean the drain pipe was obvious to remove any liquid water. If you had high humidity in there, I can't say what the drain would do in that case, although I don't think there's a motive force to -- you know, this one we're running, operating, the drywell shell is fairly warm. So any water should evaporate from there and, hopefully, would come out the drains. I mean, not as liquid water but as a vapor.

MEMBER WALLIS: What happens to the air gap? Do you ventilate it in some way? It just sits there, sits there?

MR. PAIRITZ: It sits there.

MEMBER WALLIS: Silent air. So if there were oxygen in there, it would get used up if it were corroding?

MR. PAIRITZ: If there were oxygen in there --

MEMBER WALLIS: It would get used up pretty --

MEMBER SHACK: Very little.

MEMBER WALLIS: Yes.

MR. PAIRITZ: Yes. These drain pipes point straight down to the floor, too. You know, I don't think you get a lot of air movement into the

air gap. Maybe during heat up and cool down, but not during normal operation.

MEMBER WALLIS: Yes, but doesn't moisture slowly come out of concrete and things like that over a long period of time?

MR. PAIRITZ: Ray, can you answer the concrete question?

MR. DENNIS: Yes, this is Ray Dennis. I'm the civil structural lead.

The air gap, it's not an airtight environment. There's many, many penetrations to the air gap or piping penetrations that go into the reactor vessel and drywell. So it's a free flow of oxygen and it's continuously being replenished --

MEMBER WALLIS: There is an oxygen supply, right?

MR. DENNIS: Right.

MEMBER WALLIS: And you're carrying away the water vapor --

MR. DENNIS: If the water vapor is heavy enough to condense and then be carried away by the drains. But the environment in the air gap is basically the same environment you'd find in the reactor building at all times.

MEMBER WALLIS: I guess my -- my concern

is with enough water to cause corrosion, which doesn't necessarily drain out but just stays there. That's probably the worst condition for making corrosion, isn't it?

MR. PAIRITZ: I think Ray makes a good point, though, when he mentions that we have penetrations going through this air gap that would help, not necessarily ventilate it, but prevent more humidity than is already in the air from building up.

MEMBER WALLIS: Have some control over it.

MR. PAIRITZ: And again, I would point out that drywell shell is going to be a lot warmer than the ambient air.

MEMBER WALLIS: That helps you. That helps.

MEMBER SIEBER: On the other hand I don't hear any kind of a argument that says we're certain enough that there isn't corrosion because of these factors that would tell me that I don't need to go and make a thickness measurement of the linear plate. So it seems to me that that's one of the things you ought to be doing.

MR. PAIRITZ: Well, we did do that in

response to Generic Letter 87-05. We took over 50--

MEMBER SIEBER: Right.

MR. PAIRITZ: -- readings there and we could not detect any degradation from the original material specifications, and that was after 17 years of operations.

MEMBER SIEBER: That was in '87?

MR. PAIRITZ: That's correct. '86 and '87.

MEMBER SIEBER: Well, it's still an issue because some plants have found problems.

MR. PAIRITZ: That's right.

MEMBER SIEBER: And it's probably generic to this style of containment and this age group. And I understand a generic letter is in the process to ask you to look at it.

MR. PAIRITZ: Well, ISG. I don't know anything about a generic letter.

MEMBER SIEBER: ISG. Yes, okay.

MR. PAIRITZ: The other, though, as plants that have experienced this, some of them have not had this design. I know that one design in particular doesn't have the cover on the sand pocket region, doesn't have the four inch drain pipe. They just have the sand pocket drains here.

MEMBER SIEBER: Yes.

MR. PAIRITZ: There are some differences.

CHAIRMAN BONACA: What are you trying to do? I know you're trying to perform visual inspections problem.

MR. PAIRITZ: Okay.

CHAIRMAN BONACA: Are you going to perform any UT, I mean volumetric inspections?

MR. PAIRITZ: Not at this time. I will tell you that these drains, both the air gap drains and the sand pocket drains are inspected before we flood up refueling and after the bellows are well submerged looking for leakage from any of those lines. And that's what we do right now. And that is proposed action in the ISG also.

MEMBER MAYNARD: What has your experience been? Have you found leakage at times or have you never found any signs of leakage? What's your history?

MR. PAIRITZ: We've never had any leakage. Never had the three gallon per minute flow switch go off. We've never seen any leakage from the four inch drain pipe for the air gap region. We've never seen any leakage from the 4 2 inch drain

lines in the sand pocket. However, in February of 1987 as part of the plant life extension program and part of work that was going on for Generic Letter 87-05 they did find 3½ ounces water in one of the four drain lines in the sand pocket. Now this drain line comes out of the concrete. It has a 90 degree elbow and then a one foot stand pipe pointing up vertically. They noticed a little crusty material on top of the sand. They investigated that, found out that that was calcium carbonate. They removed the sand from the stand pipe and at the bottom of the stand pipe they found 3½ ounces of water.

They had that water analyzed by two different labs. It was not radioactive. It did not contain any materials that would be indicative of it coming from the reactor cavity. And it was considered to be water that had come from inside the Torus room.

These stand pipes are open to the atmosphere. If you were doing some work on top of the Torus and accidently sprayed some water or sprayed a hose, you could theoretically put some water in there. And 3 ounces, 3½ ounces isn't very much.

And I also think the calcification at

the top of the surface there would indicate that the water came in through the top, calcified the sand and then sat in the bottom there.

So we don't believe that we've ever had any leakage from the air gap or for the sand pocket region.

MEMBER ARMIJO: Have you ever done anything to confirm that that sand pocket region is dry, or can you?

MR. PAIRITZ: Well, the other three drain lines, they took the sand out of those stand pipes. There was no water there.

The top of the stand pipe is at the same elevation as the bottom of this drain right here. So even if the stand pipe were full of water, the level in the sand pocket would still be down here. The stand pipe would have to be overflowing for there to be any water building up into this area.

We did remove part of the concrete floor inside the drywell and do UTs on this area. And, again, we compared that to our original material specifications and we can't detect any thinning there.

CHAIRMAN BONACA: You did that, what, 19 years ago?

MR. PAIRITZ: 1986 and 1987.

CHAIRMAN BONACA: Now on your slide number 16 you're saying that drywell shell is managed by the primary containment is ISI, which again advised to specifically address the ISG.

MR. PAIRITZ: Correct.

CHAIRMAN BONACA: How --

MR. PAIRITZ: The ISG recommends doing a surveillance on your drain piping to verify that you're not having any leakage. It talks about a cover n the sand pocket, which we have. And using the IWE program to verify no significant corrosion. Of course, that's from the inside the drywell.

CHAIRMAN BONACA: It doesn't tell you anything about what happens on the outside of the wall. So you're left with a question about the past -- projected future?

MR. PAIRITZ: Right. We have no reason to believe that there is any water in those areas.

CHAIRMAN BONACA: The steel liner is your containment boundary, right?

MR. PAIRITZ: That's correct.

Anyway, just to finish this slide, we do have the 18 gauge galvanized sheet metal cover over the sand pocket region. As I mentioned there are 4

two inch drain lines that would drain any water from the sand pocket region.

We talked about the stand pipes filled with sand. I think that's all I want to cover on this slide.

Now with regards to the proposed ISG 2006 01, we've talked about the UTs that we did in response to Generic Letter 87-05. Again, we compared those to our original materials specifications and we can't detect any wall thinning or degradation there.

Again, the air gap and sand pocket drain outlets are visually inspected, as prescribed by the ISG. The top of the sand pocket area is sealed with the galvanized steel sheet metal. The drywell shell is managed by the primary containment in-service inspection program, the IWE program and we will revise it to specifically call out those procedures that already exist that inspect the drains.

MEMBER ARMIJO: Were those 1987 UT inspection points, are they still accessible? Were any provisions made to have them still accessible or were they concreted over?

MR. PAIRITZ: Well, they took readings up in the air gap region 2. Those are marked on the

inside of the drywell.

MEMBER ARMIJO: I'm talking about sand pocket.

MR. PAIRITZ: Jim, do you have any idea? I mean, I know where we excavated. I don't know if the grid is still there that they used. Ray Dennis, please?

MR. DENNIS: Yes. This is Ray Dennis again.

Rather than fill the holes completely in with concrete, they filled them in with a sand type material and then put basically a concrete plug over them.

MEMBER ARMIJO: So they would be --

MR. DENNIS: They'd be relatively easy to inspect again. It would just be a matter of removing a few inches of concrete rather than several inches.

MEMBER ARMIJO: Yes. That's great. Because --

MR. PAIRITZ: But whether or not they have the grid the work that they used to ensure that you're looking at the exact same place I think is more the question.

MR. DENNIS: Yes. These spots are

readily identified in our program where they are. Plus, they're relatively easy to pick out given their surrounding area.

MEMBER ARMIJO: So it would be an ideal measurement. You've got a 1987 measurement, possibly a later measurement at pretty much the same location without tearing up the whole plant to get at it? It's probably more doable than other people.

MR. PAIRITZ: I can't say. I mean, it could be done.

MEMBER ARMIJO: I don't want to put words in your mouth.

CHAIRMAN BONACA: No. I would like to hear at some point from the Staff, you know, what's the logic for accepting. Here, more than anything else I'm thinking about precedent. You know, we had some decisions and recommendations for TVA, Browns Ferry. And it doesn't seem to be a consistent approach that we're taking on this issue.

MR. ASHAR: Dr. Bonaca, I am Hans Ashar with Dresden with Division of Engineering, NRR.

While reviewing this particular application before this, I had reviewed close to about a dozen other Mark I containments. Every time I look for the telltale signs as to what could have

caused partial area of corrosion. We looked at the Dresden/Quad for example. We saw telltale signs. They have to have something done there.

We saw Browns Ferry, we felt that that there has to be something other.

And all the questions that we asked to the applicant in this case, we found almost negative -- negative to the extent that there were no water in the top of the plane near the -- in the upper area of the earlier -- can you show me the earlier sketch?

MR. PAIRITZ: Sure. Hold on. Yes.

MR. ASHAR: Upper area, there is a plane from the drywell. They did not see any, that's what they told us. Then we went to down, because the water can go into the sand pocket area. And we saw no way that water can seep into that area in the large quantities that could corrode that particular area.

So there are a number of telltale signs that we look for. We ask questions on each one of them and we found out that, hey, this particular plant does not have this type of problem. And it does not -- it's not effective in telling us anything about it.

I have written down a very thorough evaluation on this particular area because I knew that ACRS, as well as other individuals, will have some questions on this particular area.

CHAIRMAN BONACA: Well, I think my main question is we need to have a constant understanding of the issue.

MR. ASHAR: Agreed.

CHAIRMAN BONACA: And consistent approach.

MR. ASHAR: I Agree.

CHAIRMAN BONACA: I mean, we can't possibly have a tentative, you know, approach to the -- when you're telling me that you don't have significant amount of water or a large quantity of water, it doesn't tell me anything.

MR. ASHAR: There is no water problem.

CHAIRMAN BONACA: I mean, the point that Dr. Wallis was making, all you need is humidity there for corrosion, you know it's well taken.

So I'm struggling with the ISG and the way it is being interpreted by the plant that way. Because all you have is statements by the licensee for the same kind of configurations. One licensee is more insistent than other than defending that he has

no water there, so therefore -- you know, he's argumenting about something that cannot be seen.

And on the other hand that's a primary containment function.

MR. ASHAR: I fully agree. I recognize what you are saying. I'm not contradicting what you are telling me. But what I'm trying to say is this: That the question of relatedness, I understand there is a form by which everybody is to follow. And when we -- They went up to ISG. We said you are going to talk about various things, okay, like the drain pipes being cleared, there is a control on drain pipes. They are going to examine the drain pipes. There is a seal. Some of the plants do not have that seal that they here, okay. That makes difference as to the wetness in the sand pocket area.

It has to be quite a bit wet in order to have corrosion initiated and become something like some of the other plants had. And this particular plant does not have that type of telltale signs.

It was very difficult to put them through some kind of a UT inspections if we don't find any reason to believe that we have problems with this plant.

CHAIRMAN BONACA: Okay. Thank you.

MR. PAIRITZ: Well, that concludes the drywell shell corrosion. If there aren't any more questions right now, I'll move on to the shroud.

Concerning the shroud, I have a rollout view here. The horizontal welds are labeled on the right side, H1 through H12. We have the vertical welds labeled throughout the center of the drawing.

To give you an idea of the are we're talking about, here's a jet pump on the side.

The points I want to make here is our inspection coverages have increased from about 50 percent up to about 75 percent of the welds over the past ten years due to improvements in technology.

As Mr. Potter was saying earlier, our H3 weld here has indications on 27 percent of the inspected region, and we are able to inspect 71 percent of that weld.

MEMBER SHACK: Now is this VT1 enhanced or is some sort of UT inspection?

MR. PAIRITZ: I'll let Mr. Potter answer that.

MR. POTTER: This is Dave Potter from Monticello.

The 73 percent converge on the H3 weld

was from UT inspection.

MEMBER SHACK: That's a creeping wave kind of thing?

MR. POTTER: There's three transducers that were used in the package, but I don't recall if there were a creeping wave, a sheer wave and what angles they were used. The processed was qualified in accordance with the PIP processes for crack identification.

MR. PAIRITZ: And moving on to the H1 weld, 16 percent of that weld showed indication and we were able to look at 75 percent of that weld.

And then the other horizontal welds that were looked at it was less than 10 percent indication on varying degrees of inspection area.

The inspection results and evaluation to allow inspection frequency to remain at the maximum allowed ten year interval for circumferential welds, for our horizontal welds.

We have looked at three vertical welds per the BWRVIP. The inspection frequency for these welds is established by inspection coverage.

MEMBER SHACK: Do you happen to know whether these vertical welds, you know do they hit high fluence regions or do they happen to hit low

fluence regions? It's kind of a random event?

MR. PAIRITZ: Mr. Potter?

MR. POTTER: This is Dave Potter from Monticello.

The regions, as shown on the diagram, the V3, V4, V1 and V2 are relatively high fluence areas.

MEMBER ARMIJO: Just a quick question. Since you've instituted hydrogen water chemistry have you noticed any change in any of the growth rate or the initiation of cracking in the shrouds?

MR. PAIRITZ: I'll let Mr. Potter address that. He's the expert here.

MR. POTTER: Since we've instituted hydrogen water chemistry at Monticello, we have three inspections to our credit. One that was performed in 1994, another performed in '96 and this most recent one in 2005. The crack indications that we've identified in all three of those inspections have not demonstrated substantial crack growth. So our assumption has to be is that the cracking occurred before hydrogen water chemistry was instituted.

MEMBER ARMIJO: How about initiation?

MR. POTTER: The initiation that we've

seen, I wouldn't call it substantial. A lot of it has to do with UT uncertainty and our coverage that we've gotten from previous inspections.

Our '94 inspection we did not have a lot of coverage. And as we've spoken to, or as Joe spoken to a moment ago, we increased our inspection coverage from 1996 all the welds were approximately 50 percent to 2005 where they're 75. So we're actually, the cracks that we were seeing were basically in the areas that we hadn't inspected before.

MEMBER ARMIJO: Okay. Thank you.

MR. PAIRITZ: Well, that covers crack growth.

We feel that the moderate hydrogen water chemistry has effectively contributed to mitigating crack growth on our shroud, and we will continue to manage the shroud per BWRVIP guidance.

CHAIRMAN BONACA: Well, you do have additional cracking that you are monitoring that way. Are they internals? For example, on the tack welds on the jet pumps set screws and so forth. Those cracks, I mean you just simply monitor the size of the crack and whether or not they're propagating further?

MR. PAIRITZ: I'll defer to Mr. Potter again?

MR. POTTER: Yes. This is Dave Potter again.

The cracking that we've identified on the jet pump set screws we periodically reinvestigate to make sure that they are not behaving in an abnormal fashion. However, the safety concern of the jet pump's tack screws is minimized, basically, due to the crack geometry and what the purpose of those tack welds are. And that's basically to keep the set screws from rotating out.

CHAIRMAN BONACA: Okay. All right. That's the function. I didn't know that. I didn't understand.

I have another question, by the way. It's more curiosity. When in the application you talk about the belt line nozzle and the fact that the weld material is not known insofar as CU and nickel content. Could you tell me about it? Because there is a technique you're using. You're averaging CU and nickel on 9 sister plants. And then you're adding one standard deviation, if I remember. That, I really wasn't familiar with the technique. And maybe --

MR. PAIRITZ: I'll Michael Aleksey, answer that, our TLAA person.

MR. ALEKSEY: Was your question with regard to the N2 nozzle?

CHAIRMAN BONACA: Yes. Yes, that's right. The belt line nozzle.

MR. PAIRITZ: The one the unknown chemistry.

MR. ALEKSEY: For the N2 nozzle the nickel content was a result of industry information that we had accumulated for those types of nozzles. And we also used information from the RVID database to establish the chemistries of that nozzle.

CHAIRMAN BONACA: Yes. The reason why I was intrigued I thought that was a process that has been reviewed and approved. I mean, it uses hits from 9 sister plants or similar plants.

MR. ALEKSEY: Yes.

CHAIRMAN BONACA: Averages it and then adds one standard deviation. So is it a process that the NRC is familiar with and is it a approved process?

MR. ELLIOTT: I don't know. Excuse me. This Barry Elliott.

I can't hear you, so I can't hear what

you're asking.

CHAIRMAN BONACA: It's the belt line nozzle I'm talking about.

MR. ELLIOTT: Okay. Yes. What happened is the belt line nozzles -- they aren't in the belt lines. They're slightly above the belt line.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: But the fluence has gone up because of license renewal. Also, because of the way they're calculating the --

CHAIRMAN BONACA: That's right.

MR. ELLIOTT: -- fluence. They're doing a very conservative thing with the fluence here. And so now these nozzles are getting above the criteria which we say you have to evaluate.

So they had to go out and evaluate the nozzles. They have chemistry for the nozzles. What they didn't have is underradiated properties for the -- because the nozzles were built a long time ago and they didn't have full C harpy curves, from what I remember. So they went out and they got what's equivalent to that. And went through their other nozzles in the BWR fleet made the same way, and they used that data. And then they establish a confidence interval for that data. And they used the 95

percent confidence interval lower bound for their upper shelf energy unirrradiated.

And we have accepted similar things to that.

CHAIRMAN BONACA: So this is a process you accept?

MR. ELLIOTT: Yes, we accept that.

CHAIRMAN BONACA: Although, I mean you're not certainty that the percent of Cu and nickel are identical? Nine sister plants, I mean they were similar plants.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: But you don't have specific information about this plant?

MR. ELLIOTT: No. We don't have specific information about this plant. But we feel that we looked at how they were made, the nozzles were fabricated and they were fabricated equivalent ways and the properties should be about the same.

CHAIRMAN BONACA: By the same vendors?

MR. ELLIOTT: I don't remember if we had the same -- I'm not sure about the vendors.

MR. MEDOFF: This is Jim Medoff.

What Barry is saying is true. We've evaluated the VIP processes for the vessel

materials. And it's based on weld fluxes, how they were laid down. So they grouped all those type -- like a shielded metal arc welds, they gathered the data for all that type of welds and then they came up with their statistical analysis.

CHAIRMAN BONACA: Well, I was expecting that there will be a reference to some BWR always group activity to --

MR. MEDOFF: There is, VIP 86.

CHAIRMAN BONACA: -- to provide this kind of -- I mean without any pedigree to this package of information, I'm only left on this averaging that is stated in a little footnote in the application. So since I am not the specialist in metallurgy, but I know the importance of Cu in nickel in the welds.

MR. ELLIOTT: We had to get an estimate of the upper shelf energy for these forgings. So the only thing we look at is the fleet, what the whole fleet has for forgings. And that's what they did. And then we used a 95 percent lower confidence bound to establish its properties. And we've done that in other cases where we don't have properties. We used the entire BWR fleet and then established low bound properties for welds that don't have properties.

And in this case we did it for the forgings.

CHAIRMAN BONACA: I return to my metallurgical colleagues here and say how comfortable are you with all this?

MEMBER ARMIJO: Well, you know, I thought I heard that they knew the chemistry but they didn't Charpy data. And they created the Charpy data by a comparison with the rest of the industry and then used a lower bound that was pretty conservative.

CHAIRMAN BONACA: I can remember that 10 years ago, 15 years ago we were -- anyway --

MEMBER SHACK: Yes. I mean, you know you just can't go back and recreate that data.

CHAIRMAN BONACA: Absolutely.

MEMBER SHACK: So you try to take a conservative answer and --

CHAIRMAN BONACA: Is it conservative, that's always the question. And that's what we're looking for.

MEMBER SHACK: It is quite likely to be conservative.

MEMBER ARMIJO: I think it's conservative.

CHAIRMAN BONACA: Okay. That's --

MR. PAIRITZ: Are we ready to move on?

CHAIRMAN BONACA: Yes, let's move on.

MR. PAIRITZ: Okay. The last topic I will talk about is the steam dryer. The steam dryer is in scope for license renewal at Monticello. It's a square hood dryer design. It looks like this.

In 1998 we inspected the dryer and we noted indication in the area of the 324 degree jacking bolt tack weld. Is down here in the blowup on the bottom right. It was analyzed and determined not to be structurally significant.

In 2001 we again reinspected this area and found no additional indications and no change in the indication at the 324 degree location.

In 2005 we did a comprehensive inspection on the dryer. We specifically looked at areas of dryer failures at other sites, and we did not find any indications are those areas.

We did find some acceptable indications on dryer shell behind three of the lifting lugs and on the right side of the guide rod channel 215 degrees. Right here. And then we found behind the lifting lugs on the shelves some indications in three out of the four lifting lugs. Again, these were analyzed and confirmed to be not structurally

significant.

We will be inspecting the dryer in 2007 again to confirm continued acceptability. And we plan on managing the dryer in accordance with the BWRVIP.

Dryer questions?

MEMBER WALLIS: How does it compare with other dryers? The various dryer designs, some of which have more problems than others, how does --

MR. PAIRITZ: I'll have Mr. Potter answer the question.

MR. POTTER: Could you clarify your question for me? Are you talking in general the dryer design or --

MEMBER WALLIS: There are about four or five different versions of this GE dryer, Quad Cities, Dresden, Vermont Yankee and so on. And some of them had more problems than others. And I just wondered how yours fitted into this sort of spectrum of different shapes and histories?

MR. POTTER: Okay. This is Dave Potter from Monticello.

There is in essence right now four types of dryers that are used in the industry. You might even consider five depending on how you cut it.

There's the square hood design, which is Monticello's design, which is similar to Vermont Yankee's, Quad Cities' Unit 1 and 2, and Dresden Unit 2 and 3.

Then the slanted hood dryers which a great deal of plants use.

And then the last would be the curved hood dryers.

Finally, the very last design would be the new dryers that have been installed in the Quad Cities and Dresden plants. So Monticello's dryer is similar to that. The original Quad Cities Unit 1 and 2 and Dresden Unit 2 and 3 and the Vermont Yankee dryers which did experience the failures.

Does that answer your question, sir?

MEMBER WALLIS: And you haven't seen the same kind of thing that they've seen?

MR. POTTER: No. The failures that we're seeing at Quad Cities and Dresden were flow induced type vibration failures that were seen basically on the plate -- this plate region right here as well as this plate cover view and this plate region right here or this seam weld. Those areas were inspected at Monticello in 2005 and we did not identify any cracking.

MEMBER SIEBER: I think there are differences between the units. For example thermal megawatt output.

MEMBER SHACK: Core power density are a lot--

MEMBER SIEBER: Core power -- well steam flow.

MEMBER SHACK: Right.

MEMBER SIEBER: The steam header diameter. And so some dryers are more susceptible than others because of different environment. This apparently is a milder environment than plants that have shown more damage.

Do you have any idea what the steam velocity is at the outlet of the reactor nozzles?

MR. POTTER: This is Dave Potter again. To be absolutely honest with you I have looked at that number and compared our numbers to the industry. But from memory I can't recite the velocity and feet per second.

MEMBER SIEBER: Can you say whether it's higher or lower?

MR. POTTER: I can say that it is definitely lower than -- this is Dave Potter again.

I can say that the steam line velocity

is definitely lower than the Quad Cities Unit 1 and 2 and Dresden 2 and 3 at their extended power uprate conditions. And Vermont Yankee, I know we are very close, but I don't recall whose velocity is higher.

MEMBER SIEBER: It sort of all ties together, at least in my mind.

MR. PAIRITZ: Any more dryer questions? If not, the last topic I'll cover is on the commitment process. Monticello's made 60 commitments to enhance aging management. The commitments are described in the Monticello license renewal updated safety analysis report supplement.

All Monticello commitments are entered into the corrective action program. And this ensures that there is a owner and a due date. The process was looked at several times during the audits and inspections.

Any questions on the commitment process?

MEMBER SIEBER: Well, the due date is probably when your license expires, right?

MR. PAIRITZ: Well, most of them are --

MEMBER SIEBER: Or they all become due at once?

MR. PAIRITZ: -- prior to the period of extended operation. There are a few that are before

that.

MEMBER SIEBER: Yes. The question is do you have a schedule as to when you're going to do each of the items that you have in your commitment tracking system?

MR. PAIRITZ: Yes. We have put together a level 1 type schedule as to when those will be accomplished and be part of our implementation effort.

MEMBER SIEBER: Do you have the resources to do the work?

MR. PAIRITZ: Yes. We got people working on implementation right now. A couple of contractors, some of the people that were on the team. And that will continue.

Finally we're at the end. Are there any other general questions that we can answer.

MEMBER SIEBER: You mean you would like more questions.

MR. PAIRITZ: I'm here to answer them.

MEMBER MAYNARD: A comment. I do appreciate you including your backup slides in the package. I do appreciate that.

CHAIRMAN BONACA: Any additional questions for the applicant? None. Thank you for

that. It was a pleasure.

MR. PAIRITZ: Thank you.

CHAIRMAN BONACA: And we'll ask the Staff now to present the SER.

MR. ZIMMERMAN: Dan Merzke the Project Manager for the Monticello review and Patricia Lougheed will lead the Staff's presentation.

MR. MERZKE: All right. Good afternoon, gentlemen. My name is Dan Merzke. I'm the Project Manager for the Staff review of the Monticello license renewal application.

Joining me today is Patricia Lougheed from Region III. She's our inspection team leader. Also in the audience is Peter Wen, who is our audit team leader. And supporting all of us are the technical reviewers in the audience to answer any questions that I can't answer for you.

The introduction will be start off with an overview. We'll give you the plant and the application followed by a discussion of the results of the scoping and screening results.

I'll turn the mike over to Patricia who will discuss the results of the license renewal inspections.

And then I'll take it back over and

finish with the Section III results of the aging management review and the time-limited aging analyses.

The application was submitted to us by letter dated March 16, 2005. The Monticello plant is General Electric BWR 3 design with a Mark I steel containment, as already discussed. 17075 megawatt thermal rated with a 600 megawatt electric power, and that includes a 6.3 percent power uprate approved in 1998.

Current operating license expires September 8 of 2010.

And the plant, as already discussed, is located approximately 30 miles northwest of Minneapolis.

The draft SER was issued in April 26, 2006 with no open unconformity items. It also included three license conditions. They're the standard three license conditions for all the approved plants so far.

We already discussed, Jake mentioned that there were 113 form RAIs issued, which is significantly lower than standard review.

And I think Jake touched on the fact that we considered it a pretty good quality

application. The applicant went back and did a thorough review of historical RAIs from previous applications and tried to address those issues up front.

In addition, we had 260 audit questions between the scoping screening methodology and the GALL audits.

And approximately, and as discussed earlier, about 95 percent consistency with the draft GALL Report revision 1, which was issued in January of 2005. When the final GALL was issued in September 2005 we did a scrub of that to make sure that everything was covered.

During the review we did find some minor components which were brought into scope. And I'll discuss those during the scoping and screening section.

Continuing on with the overview, the audits were conducted during June and July of 2005. Regional inspections were conducted in January and February of this year.

Section 2.1 covers the scoping and screening methodology. During the scoping and screening methodology audit the audit team reviewed the current licensing basis for flood control

measures and determined that storage steel plate and floor hatches designed to be installed for flood control were not included within the scope of license renewal. The applicant initially did not include components storage in a warehouse within the scope of license renewal. After further evaluation and an extended condition, the applicant brought these components into the scope of license renewal.

In Section 2.2 the plant-level scoping, the Staff determined that there were omissions of systems or structures within the scope of license renewal.

For Section 2.3, the mechanical systems, the Staff reviewed 36 mechanical systems, which was a 100 review.

During the scoping and screening review the Staff was unable to determine the scoping boundary for 17 areas in the boundary drawings. The Staff requested that the regional inspection team visually inspect these areas to ensure the scoping boundaries were in accordance with 10 CFR 54.4(a). The inspections resulted in a length of steam piping with a steam trap in the emergency diesel generator room being brought into scope. And I'll mention, that one was brought into scope because basically it

was below the floor deck plating in the emergency diesel generator room. And the applicant considered the floor as the boundary. However, it was not a robust boundary because you could see through the deck plating down into the area underneath. Any steam coming out of there was going to impact or potentially impact the operating temperature of the EDG room. So the applicant agreed to bring that steam piping and steam trap within the scope of license renewal.

In addition during another walkdown, one of the floor drains in the sodium hydrochloride building which penetrates the floor into the intake structure was also identified as being needed to be brought into scope.

Section 2.4 covered the containment structures and supports. Staff found no omissions of structures or supports within the scope of license renewal during the review.

For Section 2.5 the review of scoping for the electrical system identified a motor control center which was found to be outside the scope of license renewal. It supplied power to the tank heater for a standby liquid control tank. Since standby liquid control system mitigates an

anticipated transient without scram or ATWS event, the Staff determined it should be brought into the scope of license renewal in accordance with 10 CFR 54.4(a)(3). The applicant determined that the motor control centers are active components so they were screened in accordance with 10 CFR 54.12(a)(1).

During the regional inspection the inspectors determined that 480 volt load center breakers should be scoped in. The applicant determined these are active components also, so they were screened out in accordance with 10 CFR 54.21(a)(1).

To conclude the scoping and screening summary, it was the staff's determination that the applicant's scoping methodology meets the requirements of 10 CFR 54.4 and the scoping and screening results as amended included all systems, structures and components within the scope of license renewal and subject to an aging management review.

I'd like to turn it over now to Patricia Lougheed from Region II who will discuss the license renewal inspections.

MS. LOUGHEED: Hello. I'm Patricia Lougheed. I was a lead inspector for the license

renewal inspection conducted at Monticello.

My slide is on page 6 -- well, the one that's shown there. Basically gives you some of the logistics information about our inspection.

One thing that I would like to note is that on this inspection I did have a person, a metallurgist who really looked into a lot of the core internals of the BWRVIP program to make sure that it was being implemented in accordance with what was proposed for license renewal. And to make sure because there was not an official commitment right now that NRC regulates or this program. So it was ensuring that it was going to be brought forward into license renewal properly.

Going on to my next slide, Dan touched briefly upon the scoping and screening area. We did look at all the issues that were brought forward from the audit inspection. It was interesting, besides the two cases where there were items that were brought into scope, there were also a number of areas most particularly what the licensee called the 985 pump room where there were components that were identified as being in scope that really did not need to be in scope. And there were quite a few discussions during our inspection to clarify whether

those items really should have been an in scope or not. So there were some removals of things from the scope as well as some additions.

CHAIRMAN BONACA: For understanding better the logistic. You already had in hand the audit report?

MS. LOUGHEED: We had the audit report.

CHAIRMAN BONACA: So that really was a big help already --

MS. LOUGHEED: Right.

CHAIRMAN BONACA: -- in determining what is consistent or exceptions and enhancements.

MS. LOUGHEED: Right.

CHAIRMAN BONACA: And you could start from that?

MS. LOUGHEED: Right. And there's always what we do in the region and the inspections is that we look at the boundaries. Not the things that are definitely in scope, the safety systems or things like that. We look at those where they have nonsafety safety interfaces, where there's nonsafety systems that are going to be in the vicinity of safety systems. We looked at what the actual barriers were to make sure that there actually was separation. Because it was not very obvious on the

license renewal drawings.

CHAIRMAN BONACA: I had a question, and that doesn't go to this application. It's more general.

You know, when you do PRA you find that you have a lot of safety related components and others important as you thought they were. And you also find that the few, or a minor population of components which are nonsafety related are critically important for certain sequences. That's really coming from the insides of the PRA. But there is no -- I mean, license renewal does not apply to these components.

MS. LOUGHEED: That is true.

CHAIRMAN BONACA: Do you find that the licensees however are aware of the importance of those components and take care of them or --

MS. LOUGHEED: My impression, and I can't say that this is necessarily that we looked at it on Monticello specifically. But licensees where they have components that their PRAs have shown them to be risk significant, they tend to pay more attention to them because of that.

CHAIRMAN BONACA: Yes.

MS. LOUGHEED: Simply a lot of times

because it becomes a matter of economics more. You keep those pieces of equipment operating well and your risk, and therefore your chance of a shutdown go down.

So even though they're not considered important to safety, they are treated with more significance than things that are not risk significant at all.

CHAIRMAN BONACA: Good.

MS. LOUGHEED: And I'll also the little caveat that I think that a lot of the reason that some of the safety systems don't show up as being risk significant is because of the defense-in-depth concept. You know, when you putt redundancy upon redundancy well from a PRA aspect --

CHAIRMAN BONACA: Right.

MS. LOUGHEED: -- that does drive down the significance.

CHAIRMAN BONACA: Right. Yes.

MS. LOUGHEED: Basically our conclusion, and I probably should say we did do a lot of walkdowns including into some fairly high radiation areas. Our metallurgist also spent a number of hours reviewing videotapes of the vessel internal inspections and various welding inspections, areas

that obviously he would not have access to with the plant at power. So we did look at quite a bit from a physical aspect, not just relying on the paperwork and things like that.

Overall, we found that with a few minor exceptions the systems were appropriately scoped. We felt that we concentrated on the ones that were most suspect rather than the ones where we knew 100 percent was going to be thrown into scope.

The applicant did submit some clarification because they were coming up to doing their annual submittal for the license application while it was under review. A lot of the things that we had identified were brought forward into that and were submitted in that way.

Going on, we also looked at aging management. My slide says that we reviewed all 33 aging management programs, where I notice that the applicant said that there were 36 programs. I'm still scratching my head which three we missed. We really spent a lot of time on this one partly because of the team that I had and the abilities of that team to go in and look at a number of systems.

We found that the aging management programs were implemented as described. That the

enhancement and exceptions that were being proposed were acceptable.

We did identify some minor inconsistencies, and those were either captured in a revision to the application or in the corrective action program. However.

CHAIRMAN BONACA: We talked about the containment liner?

MS. LOUGHEED: Right.

CHAIRMAN BONACA: What's your opinion? I mean, you went there and looked at it.

MS. LOUGHEED: Monticello is not one of the plants that I would worry in Region III about containment liner problems. All right. There are a couple of plants that I have concerns about their containment liners, but Monticello is not one of them.

CHAIRMAN BONACA: Okay. Thank you.

MS. LOUGHEED: Basically that's -- I know you've read through the inspection report in some detail. We didn't find anything in there either scoping, screening or aging management which we felt would cause any sort of a hinderance to the license being renewed. Overall, we found Monticello to be in very good condition.

CHAIRMAN BONACA: But I must say that I'm very impressed by the inspection report and by the information from the audit. And I think they're quite insightful.

MEMBER SIEBER: I concur with Dr. Bonaca's opinion. A very good report.

MEMBER MAYNARD: Yes, I agree. It looked like you did a very thorough job.

I've got one question. One of the things in the inspection report that came out, I don't think it necessarily associated with the scoping itself, but on the failure to dismiss and relief request. Was that something that your inspection team found or is that something that just occurred while you guys were there?

MS. LOUGHEED: No. It was something our inspection team found. I very definitely had a very, very, very team. Especially in the metallurgical area. And we used him to full advantage reviewing a lot of areas that we would not have been able to look at otherwise.

MEMBER MAYNARD: Good. Good.

MS. LOUGHEED: Going on, you want me to do the current performance? Okay.

Monticello is one of our good

performance in Region III. They are in column 1, which was licensee response problem column. We don't have any crosscutting issues opened. We have no major issues at Monticello at all right now. So we are following the revised oversight process with minimum baseline inspections. And we will continue to do that.

You can see the screens coming up. We are green in every area on performance indicators. And if you move on to the inspection findings, w really have a lot of areas that we're doing inspections where we don't have findings, which is where the grey comes in. It doesn't mean we're not inspecting there, it means that we haven't found anything. And the areas where we have found things, they have all been green or a very low safety significance.

CHAIRMAN BONACA: Very good. Thank you.

MR. MERZKE: Just for Patricia's benefit, the 33 aging management programs were the official aging management programs listed in the application. The two timed-limited aging analysis support programs were also considered to be aging management program. So that was 35.

Number 36 was a commitment made by the

applicant late to implement an E6 program for electrical cable connections.

CHAIRMAN BONACA: I'm sorry. Which one is the --

MR. MERZKE: It was GALL E6 program. I'll address it in a little bit and we'll have a little discussion, but --

CHAIRMAN BONACA: First of all, I want to thank you for the --

MS. LOUGHEED: Yes. We did very close to 100 percent on this one.

CHAIRMAN BONACA: Great.

MS. LOUGHEED: We found they were able to support it and we were able to get it done within the time constraints.

CHAIRMAN BONACA: Thanks again.

Additional questions for the inspection? If not, we're going to take a break and get back here at 25 after 3:00.

(Whereupon, at 3:07 p.m. off the record until 3:30 p.m.)

CHAIRMAN BONACA: We are back into session. And we are going to be reviewing now the aging management review results.

MR. MERZKE: Thank you.

I'll move on to the discussion of the Staff's review of the aging management program and reviews now.

The Staff reviewed at the time 35 aging management programs based on the application. There were 36 overall. The 36 was a late commitment by the applicant to implement the GALL E6 program, which would be consistent with GALL. And I'll discuss that a little bit more in the electrical section.

So overall there were 36 aging management programs, 29 of which were existing programs and 7 which will be new programs to be implemented prior to the period of extended operations.

Of those, 9 of them were consistent with the GALL Report and 25 were consistent with the GALL Report with exceptions and/or enhancements. There were two plant specific aging management programs; they were a bust duct inspection and system condition monitoring programs.

I'm going to start this discussion with I picked a few of the aging management programs out which involves considerable amount of Staff review. And I thought I'd go over the results of those.

The first one would be the ASME Section

XI In Service Inspection subsections IWB, IWC and IWD program. It's an existing program which is consistent with the GALL Report with exceptions.

The LRA stated that relief requests in code cases were not considered exceptions to the GALL Report. The audit team did not agree and requested the applicant evaluate all code cases and relief requests for aging management concerns.

The Staff position is that relief requests are not acceptable for aging management because they expire after ten years.

The applicant subsequently removed reference requests from the application except for one relief request which has been approved 21 months into the period of extended operations.

There were three code cases associated with this aging management program are identified to be exceptions to the GALL Report. They're endorsed by NRC in the Reg. Guide 1.147. They were N-307-2 which concerned ultrasonic testing for Class 1 bolting with center holes; N-526, which concerned successive examinations when a flaw is detected, and; N-613-N which concerned examine volume of weld and nozzles.

The Staff found these acceptable because

they're endorsed by the NRC in Reg. Guide 1.147.

The bolting integrity AMP was found to be consistent with the Gall report with enhancements. The program will incorporate guidance from EPRI technical reports which include *Bolted Joint Maintenance and Application Guide* and the *Good Bolting Practices Handbook*

. Staff determine the guidelines reflect industry practice and meet the recommendations of the GALL Report.

The buried piping and tanks inspection, an aging management program which is consistent with the GALL Report with enhancements. These enhancements are all detailed in the commitment section of the SER.

The applicant has committed to perform inspections every ten years. They will credit inspections of opportunity when excavating.

The applicant also committed to performing an internal inspection of the diesel fuel oil storage tank every ten years in addition to the external inspection.

Other enhancements include a review of operating experience to determine the susceptible locations and to perform further evaluation on

extended condition if pipe wall thickness shows a susceptibility to corrosion.

CHAIRMAN BONACA: So let me understand now for buried pipes they're going to do a inspections, but if they do not have any inspection in ten years, they'll do one?

MR. MERZKE: That is correct.

CHAIRMAN BONACA: Okay.

MR. MERZKE: Yes, sir.

CHAIRMAN BONACA: And that's consistent with GALL, yes.

MR. MERZKE: Ultrasonic testing and visual inspections completed in 1999 and 2003 showed no degradation or aging effects.

BWR vessels internals program. It's consistent with the GALL Report with exception and enhancement. The exception was that the applicant used the updated water chemistry guidelines of BWRVIP-130, as the GALL recommended BWRVIP-29. The Staff found this acceptable as it's an updated version of the same guidelines, and that was issued in 2004.

Enhancement to this program is to use the BWRVIP guidelines for inspection, evaluation and repair to the maximum extent possible.

The applicant made a number of commitments based on questions from the audit and inspection teams. They include additional top guide inspections beyond those required by BWRVIP-26 and steam dryer per BWRVIP-139.

Regional inspectors identified a couple of issues which resulted in commitments to inspect in core monitoring dry tubes per General Electric Service Information Letter 409 and spray core piping welds in accordance with BWRVIP-18.

In addition, core plate hold down bolts will be inspected in accordance with BWRVIP-25 which requires either UT or enhanced visual inspection or another inspection technique which would be reviewed and approved by the NRC.

In lieu of inspections, the applicant has committed to installing wedges to replace lateral load resistance prior to the period of extended operations if they're unable to complete those inspections.

CHAIRMAN BONACA: For core spray piping welds, if I remember, the issue was that they did not identify the flow through the welds, through the cracks that you may have.

MR. MERZKE: The issue was that they

were not doing the inspection on the welds because the welds were -- they have mechanical clamps surrounding them which replace the structural integrity of the welds. The inspection team looked at it a different way. If the crack developed in the weld, it would be a diversion path for core spray. And in case of an accident, that core spray would be diverted outside the shroud and unavailable and it might impact P-clad temperature. So the applicant decided that it would be prudent to bring those -- inspect in accordance with BWRVIP-18.

CHAIRMAN BONACA: Good.

MR. MERZKE: The flow accelerated corrosion program. This is an existing program which is consistent with the GALL Report. The application originally stated that the trigger point for conducting an engineering evaluation for nonsafety related piping would be 60 percent nominal wall thickness. Staff could find no technical basis for this number, so the applicant committed to using 87.5 percent nominal wall thickness as a trigger point for all piping susceptible to flow accelerated corrosion. The applicant uses 87.5 percent nominal wall thickness as a trigger point for evaluation for safety related piping also.

For inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. This is a new program which will be consistent with GALL and implemented prior to the period of extended operation.

The application originally indicated that medium voltage cables that are not subject to prolonged exposure to significant moisture due to inspecting for water collection and cable manholes and conduits do not require testing. The Staff position was that testing should be in addition to inspection for water collection. The applicant committed to conduct the testing as well as to inspect initially at least once every two years, and that two years comes from their operating experience.

CHAIRMAN BONACA: Now from reading the application most of these cables are just simply buried in the ground. I mean, so --

MR. MERZKE: they do have some conduit, too, sir.

CHAIRMAN BONACA: Some of them?

MR. MERZKE: Yes.

CHAIRMAN BONACA: A few. So, I mean, the first portion of this program only addresses

those few. So there's nothing you can do about that?

MR. MERZKE: Well, the applicant has not detected any water in any manholes during the inspection process. So they've not detected any moisture.

This program is supposed to be consistent with the GALL Report which will cover all medium --

CHAIRMAN BONACA: Oh, I agree with that.

MR. MERZKE: Okay. Reflecting on the fact, and I was wondering because tomorrow we're going to have presentation on this issue for current licensing value. And after feeling comfortable with the fact that this program is going to inspect for water in manholes I was startled by the reality that most of these cables are really in the ground, they're not in conduits. And so that portion of the program doesn't do much for us.

MR. MERZKE: Right. I guess that's where the testing comes in.

CHAIRMAN BONACA: Yes.

MR. MERZKE: The reactor head closure studs programs. It's an existing program which is consistent with the GALL Report. The application

did not identify any exceptions to GALL here. The audit team review determined that the use of code case N-307-2 was an exception to GALL. This code case alters the portion of the stub which examined.

The Staff found the exception acceptable because the examination will identify the relevant aging effects cracking and corrosion as the high stressed portion of the stud continues to be examined.

Inspectors also identified installed studs which exceeds 175 kilo pounds per square inch tinsel strength, which is what's recommend in Reg. Guide 1.65 to minimize the likelihood of stress corrosion cracking.

The applicant considers all these students susceptible to cracking and is implementing the preventive measures of Reg. Guide 1.65. The applicant continues to conduct ultrasonic testing and surface examinations on a ten year interval. And to date, no parent degradation has been identified.

For the aging management review results there's 100 percent review done; 36 plant systems, 18 structure in four commodity groups. I just highlighted a few areas here.

Section 3.3 in the auxiliary systems

there was a significant discussion on elastomers. The application originally identified AMRs for elastomers subject to elevated temperatures, ultraviolet or ionizing radiation. The applicant claimed no aging effect for elastomers in a plant indoor air environment. It was the Staff's position that elastomers subject to an ozone environment experienced degradation that needs to be managed. The applicant amended their application to manage aging of elastomers in an air environment using the system condition monitoring program and the one time inspection programs.

The cable spreading room Halon system will be inspected and tested every 18 months. Life to six months is recommended by the GALL Report. The GALL is based on the NFPA recommendations, which takes into consideration system failures across all industry, not just do to aging effects. Plant specific operating experience has demonstrated that an 18 month inspection interval will detect aging effects prior to loss of intended function. Staff accepted this exception because the 18 month surveillance interval is part of the NRC approved fire protection program and thus forms of an element of the plant's current licensing basis.

Section 3.5 aging management for the drywell shell, the Staff found the applicant's program for managing aging effects to the drywell shell acceptable and consistent with the proposed staff license renewal ISG which was issued for comment earlier this month.

The applicant follows the code requirements specified by ASME Section XI, subsection IWE. UT performed in the sand pocket region in 1986 and 1987 detected no degradation. The applicant instituted a leakage monitoring program which detects for water leakage past the refueling seal bellows which is in the scope of license renewal. It also detects leakage in the drywell air gap drains and the sand pocket drains. Drains are verified open and no leakage detected every refueling outage. In addition, there's an 19 gauge galvanized sheet metal cover sealed to the vessel and surrounding concrete which covers the sand pocket region. Drywell air gap drains drain any water on top of the cover, as you saw in the applicant's diagram.

MEMBER MAYNARD: When did this monitoring program start?

MR. MERZKE: I believe it was a result

of the response to Generic Letter 87-05.

MEMBER MAYNARD: So it's been in place since 1987? Is that correct?

MR. MERZKE: That's correct.

The Staff found this program acceptable to managing aging of the drywell.

CHAIRMAN BONACA: You had a comment, Sam, it was important all the --

MEMBER ARMIJO: Yes. I had a question when the UT examine was done in 1987 there's four drain lines, sand drain lines. And was a UT done in between those where there might be a low point there that wasn't drained in the sand pocket region or was it done at the location where the drain lines are?

MR. MERZKE: I don't have an answer to that. I think the applicant may.

MEMBER ARMIJO: Do you have an idea? Could we find out sometime, on call or something?

MR. MERZKE: Okay. Any other questions?

CHAIRMAN BONACA: You have those requests regarding the configuration of the drain pipe and the fact that --

MR. MERZKE: Well, look, I start --

CHAIRMAN BONACA: -- the design to accumulate.

MEMBER ARMIJO: Yes. The stand pipe design, it's kind of strange to me why it even exists. Why isn't it just cut off and if there's anything in there, it drains out onto the floor. You know, it's not the scope of the ACRS to do a design, but it seems strange to me that that stand pipe is an asset. I think it's necessary. I don't know why you guys --

MR. MERZKE: You'll have to talk about it.

MEMBER ARMIJO: You must like it for some reason or somebody likes it.

MR. PAIRITZ: This is Joe Pairitz the Project Manager for Monticello.

The stand pipe, I believe, was originally designed that way because the drain is full of sand and part of the stand pipe is full of sand. I think it was meant to keep the sand from migrating out and going all over the floor. You'd constantly be sweeping up sand.

So I looked at it and said they must have done that to keep the sand in, but that's my personal opinion.

MEMBER ARMIJO: Thank you.

I don't think it would pore out. I

think it'd just jam up in there. As long as the water gets out.

MR. MERZKE: All right. Continue on for aging management of in scope inaccessible concrete, the applicant stated and the Staff verified that the below grade environment is not aggressive. Periodic testing of the ground water will be performed as part of the structure's monitoring program.

Section 3.6 covered electrical and I&C components. There ware four commodity groups reviewed; electrical penetrations, fuse holders, nine EQ cables and connections and off-site power and station blackout recovery paths.

The Staff noted that industry operating experience shows loosening of metallic parts of the cable connections. Requested that the applicant demonstrate how this effect will be managed. In response, the applicant committed to implement a new aging management program consistent with the GALL AMP E6 electrical cable connections not subject to 10 CFR 50.49 EQ requirements prior to entering the period of extended operations.

This application was originally reviewed under the original GALL, GALL Rev. O. The E6 program was not part of that GALL. The applicant

has committed to basically implementing one of the programs implemented in the latest GALL revision.

I'd like to move on and discuss the timed-limited again analyses. The first table here summarizes the upper shelf energy for the limiting belt line components. The acceptance criteria for upper shelf energy is greater than 50 foot pounds. The applicant has demonstrated and the Staff has verified that the upper shelf energy for the limiting belt line components at Monticello will exceed 50 foot pounds at the end of the period of extended operations.

The next table summarizes the mean nil ductility reference temperature for the limiting circumferential and axial welds. The values for both are calculated to be within acceptable limits through the period of extended operation pursuant to 10 CFR 54.21(a)(1)(ii).

CHAIRMAN BONACA: A question I have, okay, this is more learning on my part, but I found for this plant a lot of equivalent margin analysis and, you know, which we haven't seen often before. Maybe it is because of BWR versus PWR, but typically we have a screening process by which you say you meet the screening criteria and you don't have to do

any further analysis.

MR. ELLIOTT: Right.

CHAIRMAN BONACA: And here I saw a lot of equivalent margin analysis. If it's a separate issue, you might want to address both. In page 422 of the application when it speaks of reactor pressure vessels circumferential weld properties and then it presents a conditional failure probability at 64 EFPY of 1.78 as an acceptance criteria. And I haven't seen that.

MR. ELLIOTT: I can't hear you. But let me just summarize.

We went through the licensee what they had to do for the upper shelf energy. And it turns out they have four plates in the -- I think it's four plates in the belt line. And one of the plates is in their surveillance program, so they actually have Charpy data for that plate.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: The problem is the other three plates they don't have enough Charpy data to know what the upper shelf energy is. And this is not something that's specific to them. There's a lot of GE plants that have the same problem.

When these plants were originally

licensed there was no requirement to do upper shelf energy testing. You just had to test in the transition region and you had to have a lower enough transition temperature so that you had adequate toughness. So they didn't do the testing on the upper shelf energy. And this is typical of a lot of GE plants.

So what GE did was they have a topical report on this issue in which they say that if you don't have specific values of upper shelf energy, they have developed a methodology, equivalent margin analysis methodology that if you have a certain amount of irradiation embrittlement, you're with their bounds of their analysis. So that's what they were first attempting to do; to show that for these plates they were within the bounds of GE and generic analysis.

CHAIRMAN BONACA: Yes. Okay. So that's likely that for GE plants we're going to see more of this?

MR. ELLIOTT: Yes. For GE plants this is very typical.

CHAIRMAN BONACA: But it is not really a marginality of this vessel. It's more like it's typical of the approach we're going to see for GE

plants, for boilers?

MR. ELLIOTT: Right.

CHAIRMAN BONACA: Well the other issue is that cable on page 422 where they're speaking of, sort of the, configuration of weld -- essentially the calculation reference, NRC calculation where a condition of failure probability as 64 EFPY is used as a criteria.

MR. ELLIOTT: Yes.

CHAIRMAN BONACA: And that's 1.78 and ten to the minus five. And I really surprised by seeing this kind of criteria used.

MR. ELLIOTT: Are we talking about the circumferential welds?

MR. MERZKE: Yes. It's the BWRVIP-05.

MR. ELLIOTT: Okay. We reviewed the circumferential welds under the BWRVIP-05 program.

CHAIRMAN BONACA: Okay.

MR. ELLIOTT: And the purpose of that review at the time was to eliminate the inspection of the circumferential welds. And GE put out their report, and we reviewed it. And we did our own analyses to convince ourselves that what they were saying was true. So we put out in our safety evaluation of that topical report our own analyses.

CHAIRMAN BONACA: Yes.

MR. ELLIOTT: And we took their fluences.

CHAIRMAN BONACA: Yes.A

MR. ELLIOTT: And we extended it, originals were 40 years. And we extended it to 64 effective full power years just to show how it would impact the analyses. And we determined that even at 65 effective full power years they would still be the criteria that we had established to eliminate the inspection of the circumferential welds.

CHAIRMAN BONACA: That's the inspection effect. Okay. Yes, that was on page 422 of the application. Bill, you were looking at it.

All right. That was to eliminate the inspection. Okay. All right. I think that you've gotten what I needed.

MEMBER SHACK: I mean, they eliminate the inspection mostly because they can't do it?

MR. ELLIOTT: No, no. They can't do a 100 percent.

MEMBER SHACK: They can't do a 100 percent, yes.

MR. ELLIOTT: But the reason we have eliminated it isn't because of that. We find that

the axial welds are much more susceptible. If something was going to happen, they're under a much higher stress than the circumferential welds. And so that the axial welds would be a precursor to what would happen for the circumferential welds. So as long as we inspect the axial welds, we're comfortable that you don't need to inspect the circumferential welds.

CHAIRMAN BONACA: Okay. Thank you.

MR. MERZKE: On to Section 4.3 the application covering metal fatigue. The applicant satisfactorily demonstrated that the cumulative usage factor, CUF, for all components subject to fatigue will not exceed 1.0 through the period of extended operations. Components evaluated are monitored by the applicant's fatigue monitoring program, which the staff found acceptable.

Section 4.4 covers irradiation-assisted stress corrosion cracking or IASCC. Components made from austenitic stainless steel exposed to a neutron fluence in excess of 5 times 10 to the 20th neutron per centimeter squared considered it susceptible to IASCC. These components include the top guide, shroud and in core instrumentation, dry tubes and guide tubes.

IASCC is managed by Monticello by the ASME Section 11 ISI sub sections IWB, IWC and IWD program, vessel internals implant chemistry programs.

In 1999 the applicant implemented the hydrogen water chemistry program to reduce the oxygenated environment also reducing the susceptibility to IASCC.

In addition to the examinations required by the ISI program, the applicant committed to conduct additional top guide inspections of the high fluence locations using the enhanced visual inspection technique.

Section 4.7 covers the environmental qualification of electrical equipment. The Staff reviewed the applicant's TLAA on environmental qualification program and concluded that the evaluation was acceptable in accordance with 10 CFR 54.21(c)(0)(ii).

Section 4.8 covered the stress relaxation of rim hold-down bolts. The applicant provided an analysis on the stress relaxation of the core plate hold-down bolts, which the Staff reviewed. The Staff found the initial evaluation unacceptable because it relied on friction, which

was not included in the generic analysis accepted in BWRVIP-25. The Staff requested the applicant provide an analysis which did not include friction. Subsequent analysis was provided by General Electric. It was comparative analysis between the BWRVIP-25 loads and the Monticello specific loads. The analysis determined that the bolt stresses at Monticello were either bounded by the BWRVIP-25 analysis or within ASME allowables. The Staff found the analysis acceptable pursuant to 10 CFR 54.21(C)(1)(ii).

To summarize the TLAAs, pursuant to 10 CFR 54.3 the Staff found the TLAA list adequate and pursuant to 10 CFR 54.21(c)(1) the Staff found that the analyses provided would be the remain valid for the period of extended operations. They were projected to the end of the period of extended operations or that the effects of aging will be adequately managed for the period of extended operations.

And pursuant to 10 CFR 54.21(c)(2) there are no plant specific exceptions.

In conclusion, the Staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will

continue to be conducted in accordance with the current licensing basis. And that any changes made to the MNGP current licensing basis in order to comply with 10 CFR 54.29(e) or (a) are in accord with the Act and the Commission's regulations.

Does anybody have any further questions?

CHAIRMAN BONACA: Any questions? No questions. We thank you for that presentation. It was very informative.

At this stage what I would like to do is to, first of all, ask the audience if you have any questions for the presenters. There are none.

What I would like to do is to go around the table and get insights on two things. One, do we need to have a interim letter. And a second question that I have is views regarding the application and the safety evaluation reports by individual members. You know, what are the most notable issues. I believe I'm scheduled for a brief update to the full Committee tomorrow or the day after. So I would like to know from you what input I should provide.

So again, two questions: (1) Should we have an interim letter, and; (2) what feedback should we give to the full Committee on this

application. And also some views that you may have on the application and the safety evaluation report.

So I'll start with you, Jack?

MEMBER SIEBER: Okay. The answer to your first question is I don't see a need for an interim letter.

My view of the application and the SER and the audit and inspection report is that all three documents were generally well done and complete. I think the application was comprehensive, even though the Staff did determine in the area of scoping there were a few minor corrections that needed to be made.

I think particularly impressive was the inspection and audit report headed up by Region III. Again, they have done an excellent job and it results in including the licensee's effort to review RAIs sent to other LER license renewal candidates. Their requests for additional information and include the answers in their application; I think that saves a lot of effort for both the licensee and the Staff. And I commend the licensee for doing that.

And the result was an unusually low number of RAIs. And I think the process more

efficient. I think it reduces burden on all parties involved. And I think shows the maturing of the license renewal process.

The inspection and audit report, again, was very thorough and well written. And basically left no stone unturned. It was very clear to me what steps the inspectors took to make their determinations.

And so I think overall I would say that it was a job well done.

In addition to looking at the application, the inspection and audit report and the SER, I also looked at other inspection reports related to that plant on the NRC's website along with their reactor oversight process, performance indicators. And I was familiar years ago with the performance of both of those northern states power plants, Monticello and Perry Island. And it appears based on what I could read and what I reviewed, that they continue to perform well, and to me that's an important factor.

So overall I was generally impressed with the quality of both the licensee and the Staff's reports. And I think the job was well done.

CHAIRMAN BONACA: Good. Thank you, Jack.

Appreciate it.

Bill?

MEMBER SHACK: I don't see any need for an interim letter.

I'm still curious about this factor of 14 in the fluence. I mean, that just strikes me as an extraordinary change in value that I can't conceive of. And if somebody could email an explanation of where it comes from --

MR. ZIMMERMAN: We'll do that. We'll get that to you.

CHAIRMAN BONACA: Okay. Sam?

MEMBER ARMIJO: Yes. I don't want to comment on the need for an interim letter. I don't know enough about the process yet to talk about that.

I think I agree with Jack's assessment overall. I think a very nice job done by the Staff and by the applicant.

I still have a nagging concern about the drywell in that I'm not sure that the UT inspection that was done was done in the worst location or the most severe location. So I'd appreciate if either the Staff or Niagara-Mohawk could tell where these inspections were done before we put that issue to

bed. If it was done in the worst case location, I think they've got plenty of margin in this plant. BWR 3s have always been our really nice little plants, low powered power density plants. And I think the plant's been very well maintained. And I think the plan to keep it that way is good.

So other than the issue n the --

CHAIRMAN BONACA: Well, let me just point out that the issue on the interim letter. If this was, for example, to be a significant issue for which we have expectations, that would be a motivation for writing an interim letter.

MEMBER ARMIJO: That's what I wanted to ask. You know,maybe we just don't have the information. But if it turned out, for example I just have this concern that there could be a low point where water's accumulated and stayed there for a long time, and that wasn't the location where the UT exam was done, it was done somewhere else. So that's really my remaining concern.

MR. ZIMMERMAN: We'll look into that, and we'll get that back to you through Tany. And we'll talk to the licensee about that.

CHAIRMAN BONACA: Otto?

MEMBER MAYNARD: And you said Niagara-

Mohawk, I don't think Niagara-Mohawk is going to get you anywhere on --

MEMBER ARMIJO: Oh, no, no. Monticello. I'm sorry. I said Niagara-Mohawk, I'm sorry. It's still a BWR, I think.

MEMBER MAYNARD: Yes.

I see no need for an interim letter. I agree with the previous comments on the overall quality, scope and depth of the reports. Especially complimentary of the inspection report there.

And I believe that other Sam's specific question on the location of these inspections, I think that most of the issues that we may have lingering a little bit on the shell is really more of a generic question and issue that we need to come to grips with than it is a Monticello specific as to exactly what's required. It appears to me as though they're doing exactly what the interim staff guidance is requiring and have done that. So I think it's more of a generic than a plant specific force.

CHAIRMAN BONACA: Okay. Thank you.

Yes, I share some of the views of the rest of the Committee.

First of all, I was impressed by the

clarity of the application, and most of all the inspection reports. I mean they were quite informed, they provided a lot of information.

Regarding the liner, containment liner, you know the presentation from the inspector leader here gave some confidence. Because, I mean, they probed the issue, they went back and looked at it.

I still believe, however, that it is somewhat concern to me and I tend to agree with you, Otto, that it is a generic issue right now. You know we don't have a very clear basis for saying Browns Ferry should inspect and Monticello should not or doesn't need to. I mean I don't understand yet what makes the big distinction there, okay. And I think we have to clarify this issue.

In addition to that, I'm kind of concerned about license renewal and all this inaccessible components. I mean, the issue is not only the liner. The issue is the cables we are going to discuss tomorrow on this Generic Letter. The issue is piping, which is buried under. And you know these components are not going to operate forever. You're going to have some incidents of degradation tied to aging and I'm not sure that the programs we have in place are going to address the

issues in a complete fashion.

I know going back to the containment liner, I mean I am puzzled by the guidance that we have licensees by which we impose a requirement for an inspection on one and we do not on some other. It is all left to the judgment of the reviewer. I think it's an important issue that we have to look at.

If that was my plant and I have been 19 years without looking at it, I would commit to do an inspection. Now does it meet however the requirement of the rule? It sounds like it does. So, you know, my sense is is maybe we don't interim letter. The only purpose of an interim letter would be for us to say to recommend that they have an inspection done. And, you know, my sense is that let's leave it as a generic issue.

And I think it will be interesting to gain an understanding of this issue as we go forward so that we have a better understanding of when we're going to ask for an inspection and when we're not.

MR. ZIMMERMAN: In fact, tomorrow at 3:15 we're scheduled to come over here and brief you on the ISG, so that will prompt further dialogue on the issue.

CHAIRMAN BONACA: Yes. Okay. Good. And that brings it to the table anyway.

So outside of these comments, I mean I think that again it sounds like this is a good plant, has a good operating history. It seems to be ready for moving on to --

MEMBER SHACK: Well, I'm impressed when they found a number of SAMAs that would improve their safety, they went out an implemented them.

CHAIRMAN BONACA: Yes.

My concluding statement, I agree with the other comments of the members. Very low number of RAIs, by the way. It is a real improvement in the process. And I think we're getting to a maturity of the license renewal process.

Okay. So you've got our comments. We're not going to have an interim letter, at least we're not going to recommend one to the full Committee.

And I'm going to turn around and see if there are any further questions or comments regarding these applications from the public. If are no further comments, this meeting is adjourned.

(Whereupon, at 4:10 p.m. the meeting was adjourned.)