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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

October 3, 2006

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF PLANT LICENSE RENEWAL SUBCOMMITTEE

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TUESDAY,

OCTOBER 3, 2006

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Dr. Otto Maynard, Chairman, presiding.

MEMBERS PRESENT:

OTTO MAYNARD	Chair
GRAHAM B. WALLIS	Member
WILLIAM J. SHACK	Member
SAID ABDEL-KHALIK	Member
J. SAM ARMIJO	Member
MARIO BONACA	Member
OTTO L. MAYNARD	Member
JOHN D. SIEBER	Member

ACRS STAFF PRESENT:

LOUISE LUND

FRANK GILLESPIE

HANS ASHER

RICK SKELSKEY

DONNIE ASHLEY

MICHAEL MODES

JIM DAVIS

KEN CHANG

MIKE HESSLER

ALSO PRESENT:

MIKE GALLAGHER

PETE TAMBURNO

AHMED OUAOU

TERRY SCHUSTER

FRED POLASKI

PAUL GUNTER

RICHARD WEBSTER

C-O-N-T-E-N-T-S

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

1:32 P.M.

CHAIRMAN MAYNARD: This meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Plant License Renewal Subcommittee. I am Otto Maynard, Chairman for this subcommittee meeting. ACRS members in attendance are Graham Wallis, William Schack, Mario Bonaca, Jack Sieber, Said Abdel-Khalik and Sam Armijo. Our ACRS consultant, John Barton is also present. Cayetano Santos with the ACRS staff, is a designated official for this meeting.

The purpose of this meeting is to discuss the license renewal application for the Oyster Creek Generating Station, the Associated Draft Safety Evaluation Report and other related documents. 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 were announced in the Federal Register on October 2nd, 2006. ACRS meetings are conducted in accordance with the Federal Advisory Committee Act. They are normally open to the public and provide opportunities for oral or written statements from members of the public to be considered as part of the Committee's information gathering process. I would like to emphasize that these comments should be limited to issues associated with the Oyster Creek Generating Station License Renewal Application.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, the Region 1 office, and the Amergen Energy Company. We have also received requests for time to make oral statements at today's meeting. Mr. Paul Gunter of the Nuclear Information Resource Service and Mr. Richard Webster of the Rutgers Environmental Law Clinic will make their statements following the formal presentation by the Applicant and staff.

If anyone else in the audience would like to make a statement, please notify Mr. Cayetano Santos during the break and we will try to accommodate your request during the public comment portion of the agenda. We have received one written comment from a member of the public regarding today's meeting. This comment was provided by e-mail from Mr. Bill Hering, dated October 3rd, 2006. Copies have been distributed to the subcommittee. A transcript of the meeting is being kept and will be made available as stated in the

Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. Due to the number of people, we do have an overflow room next door. The audience can see the slides in that room. So if seating is not available in here, next door there should be some seating. Also due to a large number of people, I request to turn your cell phones off or at least put them on vibrate or your pagers on vibrate to minimize disturbance in the meeting.

I will now proceed with the meeting, and I call upon Ms. Louise Lund of the Office of Nuclear Reactor Regulation to begin.

MS. LUND: Okay, thank you. Good afternoon. My name is Louise Lund. I'm the Branch Chief of License Renewal Branch A in the Division of License Renewal. Beside me is also Frank Gillespie, our Director for the Division of License Renewal. The staff has conducted a very detailed and thorough review of the Oyster Creek Generating Station License Renewal Application which was submitted in July of

2005. Mr. Donnie Ashley, 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 Mr. Michael Modes, who is our team leader for the Region 1 inspections that were conducted at Oyster Creek.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions. As a result of the review, five open items were identified which will be discussed in the presentation. This also resulted -- our review resulted in the issuance of 108 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out in the 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 2005. However, it was reconciled with a September 2005 version of the GALL report.

The GALL has certainly helped with the review by providing a roadmap. The staff at Oyster Creek provided excellent support for onsite audits and inspections that were conducted and also the headquarters review through the conference calls and numerous meetings that we've had. And would you like to make some opening remarks?

MR. GILLESPIE: Only what we tried to do and you're going to see when Donnie comes on is we're going to try to conserve the Committee's time so that we can kind of focus on questions and answers. We do have a large number of slides but we're going to try to go through them on the staff presentation very quickly and not duplicate what you're going to hear from the licensee. So we'll make some adjustments because we know, at least in this case there's a number of technical issues. This is the one plant that's the first one to have us focus on this containment shell question which is also a topic of litigation.

So you'll also find the staff being very careful and trying to be careful of their words at his point relative to saying anything too definitive about specific findings because this is not the final SE. This is the SE with open items. So with that, I'm going to turn it over to Mike Gallagher from Exelon.

MR. GALLAGHER: Okay, good afternoon. My name is Mike Gallagher and I am the Vice President of License Renewal Projects for Amergen and Exelon. For your information Amergen is an Exelon company so therefore, you'll hear both names today. Here with us today we have Tim Rausch, our Site Vice President and we also have a host of support personnel to answer any questions that may come up. Presenting with me today is Fred Polaski, our License Renewal Manager, tom Quintenz, from Oyster Creek and John Hufnagel, our Project Licensing Engineer.

Next slide, Slide 3 shows our agenda for today. Note that early in our presentation we will be discussing the drywell corrosion issue. Fred?

MR. POLASKI: Thank you. My name is Fred Polaski, I'm Exelon's Manager for License Renewal. Oyster Creek is a BWR2 with a Mark 1 containment located in Lacey Township, Ocean County, New Jersey. Barnegat Bay is the ultimate heat sink for the plant. Onsite spent fuel storage is provided in the fuel pool and drycast storage. Current capacity enables onsite storage to the current operating term with full core offload capability.

We are currently planning an expansion of the interim spent fuel storage facility to accommodate additional fuel storage through the year 2020.

MEMBER WALLACE: Is cold water involved, salt water?

MR. POLASKI: Yes, we do have salt water as the --

MEMBER WALLACE: (Microphone is not on, inaudible).

MR. POLASKI: The GALL does address salt water environments, yes. Yes. Yes, okay, all right. An expansion of the spent fuel storage facility beyond 2020 could be pursued if it's warranted. The Oyster Creek PRA was updated in 2004. Our core damage frequency and large early release frequency are shown here on the slide. Next slide, please.

This is an overhead picture of the Oyster Creek site. Just to give you a point of reference, north is to the top of the slide. The plant is located west of Route 9. The Barnegat Bay is the body of water on the right of the slide. East of Barnegat Bay is the Island Beach State Park and east of that would be the Atlantic Ocean. Water intake is provided by the Forked River at the top of the slide and discharges by Oyster Creek to the Barnegat Bay.

MEMBER WALLACE: It's a very funny river. It goes in a circle. Does it have an end or a beginning?

MR. POLASKI: That's not the original river. There was a lot of changes made when this plant was built to the original -- to the flow of the river.

MEMBER WALLACE: Where does it come in from that land? Where is the fresh water? Back there? Up there is the fresh water. So it's somehow --

MR. POLASKI: Actually, there's three branches to the Forked River. This is the north branch, this is the middle branch and the lower branch, this other branch is through here and so the original flow of this would have been down here, so this one the intake canal was drastically modified during construction.

MEMBER WALLACE: Now, there's some sort of flushing of all this by tides; is that how it works?

MR. POLASKI: And actually, the flow through the plant is greater typically than the flow down the river, so any of the flow coming down the Forked River then, flow comes through this way into the plant and back out through Oyster Creek.

And the last thing I'd like to point out on the slide is the Forked River combustion turbines which we'll be discussing later in the presentation, are the station blockout owner of AC power source and they're located adjacent to the switch yard for the plant.

CHAIRMAN MAYNARD: And you'll be getting into your agreement on the aging management program for that in your presentation.

MR. POLASKI: Yeah, we're going to talk about that later. Slide 6. Oyster Creek is currently operating in the 20th operating cycle, a plant transition at 24-month cycles in 1991 and the plant is currently operating in end of cycle coast down. Oyster Creek is in the regulatory response column of the NRC Regulatory Oversight Program with one white finding in emergency preparedness. This finding was due to an event in August 2005 when plant operators did not recognize that plant parameters met the threshold for declaring an emergency action level.

In addition, a substantive cross-cutting issue in the area of human performance was identified by the NRC staff and communicated in the recent mid-cycle performance review. One of the examples cited was the white finding in emergency preparedness. The station has completed a thorough root cause analysis of these issues and has continued to implement corrective actions to improve performance in this area.

MEMBER SIEBER: This was a failure to

report or reporting the wrong action level?

MR. POLASKI: It was a failure to respond to plant conditions when the action level occurred.

MEMBER SIEBER: Gotcha.

MR. POLASKI: And actually the declaration was made but it was made much too late for the --

MEMBER SIEBER: Gotcha, understand.

MR. POLASKI: Slide 7. Oyster Creek is one of the 15 power reactors that were issued a provisional operating license. This provisional operating license was issued in 1969. Oyster Creek's licensed thermo-power is 1,930 megawatts thermal. New power uprates have been incorporated at the plant and none are currently planned. Design electrical rating is 650 megawatts electric. The ownership of the plant was transferred from GPU to Amergen in 2000 and the current license expires April 9, 2009.

MEMBER BONACA: Before you go forth, you mentioned the emergency plan finding. That will be essentially finding on a cornerstone.

MR. POLASKI: Yes.

MEMBER BONACA: So where is the cross-cutting issue? Mean, what other items have been brought up that combine together with this cornerstone issue?

MR. POLASKI: The cross-cutting issue dealt with procedural compliance and procedural adherence.

MEMBER BONACA: Yes, okay. And so you have other examples of problems with procedural adherence.

MR. POLASKI: Yeah, there were other green findings in that quarter that were in the procedure adherence hearing.

MEMBER BONACA: In the procedural, okay, thank you.

MR. POLASKI: If there's no other questions, I'm going to now turn it back to Mike Gallagher to discuss the drywell corrosion issues.

MR. GALLAGHER: Okay, I will now give you a brief history of the drywell corrosion at Oyster Creek. The corrective actions that were implemented and how we insured the corrective actions were effective. The presentation will describe how we arrived at our overall conclusions which are the corrective actions to mitigate drywell shell corrosion have been effective, the drywell shell corrosion was arrested in the sand bed region and continues to be very low in the upper drywell elevations. The service life of the drywell shell extends beyond the year 2029 with margin. And also we have effective aging management programs to insure continued safe operation.

MEMBER WALLACE: Now, you said it was arrested in the sandbed region. Is this because you've excavated the whole sandbed area and you checked the whole thing all around?

MR. GALLAGHER: Yeah.

MEMBER WALLACE: And how often do you do that?

MR. GALLAGHER: I think the rest of my presentation will touch on all those details.

MEMBER WALLACE: Will go into that, okay.

MR. GALLAGHER: We can go through that.

CHAIRMAN MAYNARD: One other thing I'd like to make sure you touch on in your presentation is one of the observations from the inspection report were found some water. It was emptied without analysis and I think a number of the members have some questions, so if you can work that into your discussion, too.

MR. GALLAGHER: Okay, we will. Okay, just to go through some background first, and I think this will help us all. Slide 9, this is a cross section of the drywell. Early in plant life during refueling outages, water leaked through defects in the reactor water and the reactor cavity liner which I depicted in cross-hatched blue into the air gap which is depicted in red between the drywell shell in the reactor building, down to the sandbed region which is depicted in the cross hatch purple.

MEMBER SHACK: Now, is that really an air gap or is that filled with this Firebar D?

MR. GALLAGHER: There is Firebar D in that gap and then during the first operational or static test it actually presses and compresses that Firebar D. There an air gap in there.

MEMBER SHACK: I see, so the concrete is cast against it. It compresses and then you're left with a gap.

MR. GALLAGHER: That's correct.

MEMBER SHACK: And roughly what's the dimensions?

MR. GALLAGHER: Pete Tamburno?

MR. TAMBURNO: I'm Pete Tamburno, Senior Mechanical Engineer Oyster Creek. That gap is approximately three inches.

MEMBER WALLACE: How does the gap get created now, the concrete shrinks or something?

MR. GALLAGHER: No. Pete, can you go into that in detail?

MR. TAMBURNO: The gap was created by first erecting the drywell vessel. Then they applied this Firebar D to the drywell, and then they poured the concrete around it.

MEMBER WALLACE: And they -- what happened to the stuff that was in between? It disappeared somewhere?

MR. TAMBURNO: No, it's still there.

CHAIRMAN MAYNARD: When you do your pressure test, is that when --

MR. GALLAGHER: Yes, Ahmed, could you --

MEMBER WALLACE: So the gap is full of something.

MR. GALLAGHER: It was a foam. It was foam and then during the hydrostatic test of the drywell, you know, it compresses and then there's a gap.

MEMBER WALLACE: Okay.

MR. GALLAGHER: So I think what Pete's referring to the whole gap, the whole gap --

MEMBER WALLACE: It's the whole gap or --

MR. GALLAGHER: Yes.

MEMBER WALLACE: -- it's the air plus this other stuff?

MR. GALLAGHER: It's the air plus the Firebar, yeah.

MEMBER WALLACE: What do you call that stuff?

MR. GALLAGHER: Firebar D.

MEMBER WALLACE: Firebar D.

MR. GALLAGHER: It's the type of material.

MEMBER WALLACE: Fire resistant, is that what it is?

MR. GALLAGHER: It was a construction material.

MEMBER BONACA: Just a question still regarding configuration. So you're saying that -- your postulation is that there are cracks in the liner of the cavity and water will come through that down this gap. Now, doesn't it defeat the design purpose of the refueling seal to have those cracks?

MR. GALLAGHER: Yes, perhaps if I can go to the next two slides, it will show closer cross sections of this area and I'll answer that question directly.

MEMBER BONACA: That is a specific question regarding the design. I thought that the design of the seal was in fact, to prevent any water penetration.

MR. GALLAGHER: Yeah.

MEMBER BONACA: And it seems to me that the existence of these cracks in the liner by definition, they're defeating the design purpose of the seal, but anyway, so whenever you get there.

MR. GALLAGHER: I'll get there, I can get there right now.

MEMBER ARMIJO: Just to add one thing to your list of questions, when you talk about the leakage, would you address the issue of moisture geing absorbed in that Firebar D and/or chemicals that leach out of that material ultimately getting down into the sandbar region and what that -- what your views are concerning the chemistry and the corrosion you saw?

MR. GALLAGHER: Let me continue with the background and we will get into that question also.

MEMBER WALLACE: What makes the bubbles in the foam?

MR. GALLAGHER: Excuse me?

MEMBER WALLACE: What makes the bubbles in the foam in the Firebar D? Is it some kind of gaseous release by a chemical reaction or something? What makes the bubbles in the foam?

MEMBER SIEBER: There are no bubbles in

the --

MEMBER WALLACE: The foam must have bubbles if it's a foam.

MR. GALLAGHER: I'm not aware of any bubbles in the foam.

MEMBER WALLACE: It's a foam, you said it was a foam.

MR. GALLAGHER: It's a -- Ahmed, can you answer that?

MR. OUAOU: It's --

CHAIRMAN MAYNARD: Excuse me, could you state your name, please?

MR. OUAOU: Ahmed Ouaou with the Oyster Creek License Renewal Team. The Firebarrier, the Firebar D material was put in place to prevent the concrete from it being in contact with the shell and later on that material was compressed with 40 psi pressure and heat it to a temperature of 140 degrees Fahrenheit to create a one-inch gap that's required for seismic movements, for movements of the containment shell. That was basically its purpose.

It's a non -- a compressible material beyond the one-inch --

MEMBER WALLACE: I'm trying to find out what it is, chemically and so on. Is it completely neutral in terms of corrosion properties or what is it?

MR. OUAOU: It has some chlorides.

MEMBER WALLACE: Chlorides.

MR. OUAOU: Yeah, the chlorides, however, are not in the area of corrosiveness to the steel.

MR. GALLAGHER: Yes, specifically, your question about the water, when the water did wash down from this area, it does pick up -- it did pick up some of these contaminants. The water now that we've had showed that the water met the criteria for you know, non-aggressive to concrete and you know --

MEMBER SHACK: Or steel.

MR. GALLAGHER: Or steel, yes. So the -- I think we have some data on that matter, Pete, about the chloride level is less than 1,000.

MR. TAMBURNO: Yeah, the sand was tested and the ph limit for the leachate was 8.46. The --

MEMBER SHACK: I thought that was a test on the sand. Is that the sand after it's been penetrated with the stuff or that's the acceptance criteria for the sand that you're about to put in the sand bag?

MR. TAMBURNO: No, the results of the tests I'm giving you is the tests on the sand after --

that was removed, and the chlorides are 45 parts per billion and sulfates are 17 parts per billion.

MEMBER WALLACE: In that water that was tested?

MR. GALLAGHER: Yes, in the leachate that came from the sand.

MEMBER WALLACE: Does the NRC know what Firebar D is and what it's made out of and what's its properties are?

MEMBER SIEBER: Yeah, they do because it's in the SER.

MS. LUND: Hans Ashar is coming up to talk about --

MR. ASHER: Yeah, we're aware of the particular type of insulation between the concrete shield wall and steel and with the water coming out of the refueling cavity in some places when a accumulation in the same pocket area, it is contaminated that sand with corrosive kind of environment in the early days and afterwards, I believe Oyster Creek owners at that time had done a number of analysis that I recall. I don't remember all the numbers but I have seen the chemical composition and all those things. I have it in my folders but I was not ready to talk about because I didn't know it would come up at this time because they were taking out the sand, but if you --

MEMBER WALLACE: The Firebar is still there, though, isn't it?

MR. ASHER: Yes, the Firebar is still there.

MR. GALLAGHER: And I think when we go later through the presentation, we'll talk about, you know, our program that monitors the corrosion in the upper drywell and the results of that which are good. So I think that addresses the issue, what's actually going on up there.

MEMBER BONACA: I don't want you to forget about my question.

MR. GALLAGHER: We're doing that right now. If we could go to --

MEMBER SIEBER: Well, we still don't have the answer to Dr. Wallace's question as what the material is. Is it a foam, is it a fiber?

CHAIRMAN MAYNARD: I'd like to go ahead and let the licensee go on. We can come back to that if we've got it from somebody here' who's looking after it.

MR. GALLAGHER: Yeah, and we can get that specific information, also at a break.

Okay, so let me just continue with the overhead. We'll get to your question. So attached to the sandbed region are five drains designed to remove any water from this region. The sandbed drains were clogged and thus, prevented the sand from remaining dry.

MEMBER WALLACE: Say that again.

MR. GALLAGHER: The sandbed drains were clogged and thus, prevented the sand from remaining dry. This is, I'm talking about the -- you know, the initiation of the event.

CHAIRMAN MAYNARD: And this was back in the '80s.

MR. GALLAGHER: This is in pre-mid-'80s. So what I'm going through here now is, you know, the complete history, so we're starting from the identification of the problem. So I'm describing the background and identification of the problem and then we'll go through all the facets to our current aging management.

MEMBER WALLACE: You say there were some regions which were much more corroded than others.

MR. GALLAGHER: That's true.

MEMBER WALLACE: That's going to be part of our investigation, I think, as to how extensive is this corrosion, how extensive -- how well, if this is something, tell us of the details of it all the way around and help us.

MR. GALLAGHER: And we'll be getting into that, yes.

MEMBER WALLACE: Okay.

MR. GALLAGHER: Yes, sir. So, as I said, this wet sand was in contact with the drywell shell exterior and caused general corrosion of the shell in the sandbed region. To a lesser extent, there was also corrosion identified in the upper region of the drywell as you had just questioned with the Firebar. The detection of water draining from the sandbed drains and potential for drywell shell corrosion was recognized and pursued in the mid-1980s. So that's the period of time we're talking about right now.

MEMBER WALLACE: Well, I don't mean to go on forever but to get corrosion, you need oxygen as well as water and the worst condition which is something that is damp and has air there. If it's totally immersed, sometimes it's better off.

MR. GALLAGHER: That's true.

MEMBER WALLACE: Well, you have a condition where you've got air and water, so the partly drained water and there's some sort of an interface where things are really going on; is that what you had there, something like that?

MR. GALLAGHER: Well, there is an air gap there and so there is -- there was air or there is air. If I go to Slide 10 and this will be hitting into your questions. Slide 10 is a close-up of the cross-section of the sandbed. Your questions will be answered in the next slide, but this shows the sandbed area and the drain. The air gap is also shown and that's the red at the top of the slide.

MEMBER WALLACE: I understand. The sandbed is the blue and the red or -- it doesn't make sense. Where is the sandbed in this picture? Where is the torus?

MR. GALLAGHER: This might be a little bit better figure for you. That is the sandbed area that he's pointing to.

MEMBER WALLACE: Okay.

MR. GALLAGHER: The cross hatch is the shell itself.

MEMBER WALLACE: Yeah, I thought it was. So what's this blue and red stuff?

MR. GALLAGHER: All right, on that slide it didn't turn out well in this overhead because I think the projector is --

MEMBER WALLACE: So it's labeled sandbed but it isn't sandbed.

MR. GALLAGHER: Go back to that.

MEMBER WALLACE: It's something inside.

MR. GALLAGHER: Let me explain to you. This light -- these lines are too light. This is projected --

MEMBER WALLACE: Yes, the sandbed is in there.

MR. GALLAGHER: This is the sandbed there.

MEMBER WALLACE: And what's that red and blue stuff and why is that highlighted?

MR. GALLAGHER: The orange or --

MEMBER WALLACE: Red on my slide.

MR. GALLAGHER: The orange, down here that is the concrete in the inside of the containment. There's actually -- it's a sawtooth arrangement in that the -- you know, the curb is higher and then lower a threat to the drywell. So the blue is supposed to show you the top of the curb on the inside of the drywell.

MEMBER WALLACE: This is just a different piece of concrete.

MR. GALLAGHER: Yes. Well, it's the same form but it's -- it looks like a sawtooth pattern.

The sandbed area is to the right of that, and that's the white area, okay. The green is supposed to be -- that's one of the down comers going to the torus. And then the air gap is the red depicted at the top. It's the same red on the previous slide and that goes all the way around obviously, and so it connects to the sandbed area.

MEMBER WALLACE: And you're going to tell us just where the corrosion is in here?

MR. GALLAGHER: Yes, yeah.

MEMBER WALLACE: Can you point it out now?

MR. GALLAGHER: The corrosion is --

MEMBER SHACK: You're better off with the next slide.

MR. GALLAGHER: The next slide is about the refueling seal.

MEMBER SHACK: You have the line drawing of this area.

MR. GALLAGHER: Okay, where you see the shell --

MEMBER WALLACE: Where's the corrosion? Up there?

MR. GALLAGHER: The corrosion is in this area here.

MEMBER WALLACE: And not below that.

MR. GALLAGHER: Well, it's all of this area.

MEMBER SHACK: It tapers off.

MEMBER WALLACE: It doesn't go beyond that. It's just -- how do you know what happens when it goes into the concrete there?

MR. GALLAGHER: Into which area?

MEMBER WALLACE: The bottom, the very bottom. In there, what happens in there?

MR. GALLAGHER: And we'll be talking about that also.

MEMBER WALLACE: Oh, you're going to tell us all these things.

MR. GALLAGHER: Yes, that's right.

MEMBER WALLACE: Good.

MEMBER SHACK: Just while we have this drawing up, now, my understanding is you didn't have a galvanized plate the way some people do to cover the sandbed but is that a galvanized or is that some sort of plate I see there in the drawing?

MR. GALLAGHER: This here, no, that's the down comer.

MEMBER SHACK: That's the down comer.

MR. GALLAGHER: Yes.

MEMBER SHACK: And you don't have the

galvanized. Yours is open to the --

MR. GALLAGHER: Ahmed, any galvanized plate?

MR. OUAOU: We do have a cover plate around the vent header at the top of the sandbed region.

MR. GALLAGHER: At the top.

MR. OUAOU: There was one included in the design.

MEMBER SHACK: There wasn't?

MR. OUAOU: There was.

MEMBER SHACK: There was.

MR. OUAOU: Yes.

MEMBER ARMIJO: Just one last question; you said you had five drains. Were all of the drains plugged or was just a couple of them so that you --

MR. GALLAGHER: They were all plugged.

MEMBER ARMIJO: You have to assume that the corrosion was generalized around the lower part of this.

MR. GALLAGHER: That's correct.

MEMBER WALLACE: There's a filter on top of the drain pipe or something like that to prevent the sand washing away?

MR. GALLAGHER: There is a filter, and

Ahmed, the filter?

MEMBER WALLACE: That's what plugged?

MR. GALLAGHER: The filter.

MR. OUAOU: As Mike mentioned previously, the drain itself was full of sand as part of the design to avoid --

MEMBER WALLACE: It was filled with sand.

MR. OUAOU: It was filled with sand to avoid draining the sand from the sandbed region but as a result of water intrusion in the area, you have fines that mixed with the sand. You don't have the drainage and that was why it was plugged.

MR. GALLAGHER: Okay, so to get to your question on the next slide, which is Slide 12, excuse me, Slide 11, this is the reactor cavity seal area. And this -- this shows a cross section of that. This slide is useful to show the water leakage path. And basically as we indicated, the water leakage was through defects in the reactor cavity liner and worked its way into the trough area. Again, this projector is light but I think your slides are a little better.

The water worked its way -- or leaked into this trough area and some of this trough area there was low spots originally in the trough area and so the water which leaked through here, leaked down and spilled over into the air gap.

MEMBER BONACA: Now, two questions. One, how sure are you that that's the source of water since this is being contested? You've tested this water?

MR. GALLAGHER: We're very sure that that's the source of the water. Other --

MEMBER BONACA: That's an issue.

MR. GALLAGHER: Other -- during the corrective action, early on, there was other sources that were pursued such as the refueling seal and things like that and it was determined that the majority was through this other --

MEMBER BONACA: And then the question I had was, the seal is supposed to be preventing water penetration but if you have cracks in the liner you are defeating the design objective. And the question I'm raising is because whatever you do to control corrosion, to do whatever you can do to monitor, you still are defeating the design objective and fitting water through that gap. I mean, is that an initiative to try to fix those cracks or replace the liner?

MR. GALLAGHER: Absolutely, what we --

MEMBER BONACA: Otherwise the root cause of all this is not going to go away. And I mean, the goal objective of inspecting those bellows and seals is defeated by definition. Simply you have cracks and they're allowing water to come down.

MR. GALLAGHER: When we go into our program and talk about what we've done in the past and what we're committing to do for the future, we put strippable coating on the reactor cavity liner before we fill it with water during refilling outages. And that's been very, very effective to eliminate the water from this air gap.

MEMBER BONACA: You still have been getting water in these containers.

MR. GALLAGHER: Okay, we can talk about the containers now, if that's --

MEMBER BONACA: No, that's okay, you're going to talk about it later.

MEMBER SHACK: Well, let me go over this strippable coating now. You have put this -- I mean, every time you fill this with water, that's -- part of your procedure is to apply the strippable coating first?

MR. GALLAGHER: We have made a commitment that going forward, every time we fill the reactor cavity, we will put strippable coating.

MEMBER SHACK: You haven't done that every time since the problem started?

MR. GALLAGHER: We've done it, I think, every time except two outages. And --

MEMBER SIEBER: The answer is, no, they haven't done it every time.

MEMBER BONACA: That's right.

MEMBER ARMIJO: Was that just oversight or error or was it a --

MEMBER SHACK: A procedural failure?

MR. GALLAGHER: Pete, can you answer that question?

MR. TAMBURNO: This is Pete Tamburno, Senior Mechanical Engineer. There were two outages during the time frame that GPU owned the plant that the strippable coating was not put on and I believe it was during a time when the plant was announced to be decommissioned.

MR. GALLAGHER: But, you know, for clarity, we have made a commitment and we put that in our license renewal application that we will put the strippable coating on.

MEMBER SHACK: Now, when you --

MEMBER BONACA: Yeah, go ahead.

MEMBER SHACK: When you have the strippable coating in place and you're -- I trust you're still monitoring for leakage, do you get any leakage with the strippable coating in place? You're still getting leakage?

MEMBER BONACA: Yes, they do.

MR. GALLAGHER: We have had -- when we went through our commitments on this -- the current commitments, current licensing basis commitments, we couldn't find any current documentation on the monitoring of the water leakage. We've talked with people that have been in the sandbed and they have said that, you know, there is no water in the sandbed when they go in there to do the visual inspections on the coating. So we believe that our corrective actions have been effective, which I'll go in to tell you what we've done comprehensively to insure that the water is going down the trough drain and not into the air gap.

CHAIRMAN MAYNARD: I'd like for us to let the licensee go ahead, I think trying to give a history and --

MR. GALLAGHER: Yeah, we have a pretty good presentation.

CHAIRMAN MAYNARD: We can come back to these -- anything that is not answered, we can come back to but I want to leave time for us to do that.

MR. GALLAGHER: And I think we'll hit on

all your issues.

Okay, if we can skip through Slide 12, Slide 12 is basically the words that I just talked to. Okay, going to Slide 13, okay, so just to frame this again, where I'm at is we've discovered the problem and now we're determining what the problem is and the extent of it. So in the 1986 time frame, the initial corrosion monitoring program was initiated utilizing ultrasonic thickness measurements in order to determined --

MEMBER WALLACE: Taken from the sandbed side?

MR. GALLAGHER: This is comprehensively for the drywell.

MEMBER WALLACE: On the sandbed side.

MR. GALLAGHER: From inside the drywell.

MEMBER WALLACE: From inside not from the sandbed side, from inside.

MR. GALLAGHER: This is a comprehensive program to look for -- to evaluate the --

MEMBER WALLACE: It's taken from inside.

MR. GALLAGHER: So in order to determine the --

MEMBER SHACK: But when you take that from inside, you're going through the concrete and you look for a reflection off the inside wall and outside wall?

MR. GALLAGHER: No, the inside is just the liner itself. The concrete is on the outside.

MEMBER WALLACE: There's concrete there, isn't there?

MEMBER BONACA: He's not talking about the bottom.

MR. GALLAGHER: Yeah, I'm talking the accessible shells --

MEMBER SHACK: The portion of the sandbed region.

MEMBER WALLACE: Well, you said concrete on there, so how do you do take it when you've got concrete on top of the steel?

MR. GALLAGHER: If I can, what I'm trying to describe here first is, our monitoring.

MEMBER WALLACE: This seems to be important as to how good are the measurements.

MR. GALLAGHER: That's right, that's right. And --

MEMBER WALLACE: You show there's concrete on top of the steel in that region?

MR. GALLAGHER: What I'm talking about now is to determine the appropriate monitoring locations to measure the --

MEMBER SHACK: What you're saying is you've taken a thousand measurements in the sandbed region and we're asking --

MR. GALLAGHER: I didn't say that.

MEMBER WALLACE: We're asking how you did it.

MR. GALLAGHER: I didn't say that. If I can describe --

MEMBER SHACK: The UT is in the sandbed region at least some of the one thousand.

MR. GALLAGHER: These one thousand measurements were throughout the drywell in order to determine --

MEMBER WALLACE: That's misleading then. They're not in the sandbed region. What did you do in the sandbed region?

MR. GALLAGHER: It says approximately a thousand UT measurements were taken to identify the finished location --

MEMBER WALLACE: How does measuring somewhere else measure what's happening in the sandbed?

MR. GALLAGHER: -- in the sandbed region and the upper elevations of the drywell. What we're trying to say, we comprehensively took measurements throughout the dry well to identify the extent of the problem, okay.

MEMBER WALLACE: We're asking you how you did it in the sandbed.

MR. GALLAGHER: Okay, so in the sandbed region, let me turn that over to Pete and you can go into the specifics on that.

MR. TAMBURNO: Okay, this is in the early '80s before we had access to the sandbed. At that time, we did not have access to get into the sandbed so we did a sweep, 360 degrees on drywell vessel inside the drywell, that was accessible. We did not look at portions underneath the concrete, only the portions of the vessel that were accessible. There's a --

MEMBER WALLACE: So you've got no measurements in the sandbed region?

MR. TAMBURNO: No, no, there are portions of the sandbed which are accessible from the inside.

MEMBER WALLACE: Some parts.

MR. TAMBURNO: Yes, sir.

MEMBER WALLACE: But there are other parts that are not.

MR. TAMBURNO: There are other parts that are not accessible.

MEMBER WALLACE: I presume we knew nothing about what was happening there.

MR. TAMBURNO: Well, shortly after we reported that information to the NRC, they questioned about what about underneath the concrete, at which point we removed a portion of the concrete in two sections and investigated the vessel in those two portions. Our conclusions were that the information on the accessible regions were representative of the corrosion when we looked at the portions of the vessel that were underneath the concrete.

MEMBER WALLACE: That's where you found the minimum thickness that we're going to hear about?

MR. TAMBURNO: Yes, sir.

MEMBER WALLACE: And how big was the minimum thickness?

MR. TAMBURNO: At that time, there were -- the numbers varied anywhere between 1.1 which is what the vessel was originally delivered and to 0.5 inches thickness.

MEMBER WALLACE: 0.5 inches thickness. That's the thinnest I've heard yet.

MR. TAMBURNO: Excuse me, excuse me, that's incorrect, 0.85, I'm very sorry.

MEMBER WALLACE: Why did I see .603 in the report?

MR. TAMBURNO: At the time that we did our original investigation, we did not see the .603. That was later on when we gained access to the outside of the drywell by removing the sand.

MEMBER WALLACE: I'm asking all this because I'm not sure from what I've read, what the thinnest part of this drywell is, how thin it is, how extensive it is. I don't get that from the report. I get these numbers thrown out. We measured 0.85 then we found .603 but how big is it and what about the places where you didn't measure? All that stuff, I don't know. Are you going to clarify all that?

MEMBER BONACA: The .8 is referenced as an average.

MR. GALLAGHER: Yeah, there's actually two criterion we -- if I can briefly, there's different plates in the drywell and shell, as you know. So there's a different minimum thickness for each one. Sandbed, just talking sandbed, there's actually two criterion. Okay, one is for the minimum average. Okay, and that number is 0.736. And the other is for a minimum local, which is .49. So the measurements need -- you know, the criterion is to meet those. In all the areas of the sandbed, we meet those criterion.

MEMBER WALLACE: In all areas. So you've got how many measurements around to make sure that you cover all areas?

MR. GALLAGHER: So specifically, what we're talking about here is there was an investigation that was done to identify the areas to monitor for corrosion, okay. When I say these thousand points, it's throughout the drywell. Basically the bottom line is to get to your question, is that these were used to identify the thinnest areas, biased to the thinnest areas. We then set up -- there's 19 monitoring locations that are on the interior of the sandbed area that are like a grid, you know, and those are to determine the data points and they are 360 degrees around there.

So they are representative of the condition of the sandbed. Those particular points, there's a grid that's established. It's a 49-point array. Those 49 points in each of the 19 locations were taken and they were bounced off this criteria of the minimum general being the .736 and then the minimum local being the .49.

MEMBER ARMIJO: Do you have a little picture or graph showing all of the UT measurement points taken around the circumference in the sandbed region that you could show --

MEMBER WALLACE: That would help a lot.

MEMBER ARMIJO: You know, that would save a lot of questions, because I think that's our -- all of us have looked for this information.

MEMBER WALLACE: Right.

MR. GALLAGHER: We can easily -- we don't have that in an overhead. We can provide that. But these 19 locations are throughout the 360 degree of the sandbed region.

MEMBER WALLACE: Now in the torus, you've got pits. I mean, how would you find pits if you're only just looking in a few places here? You don't find pits in the drywell? You find pits in the torus.

MR. GALLAGHER: The torus?

MEMBER WALLACE: You could have a pit in the drywell, couldn't we here, that's bigger than these average of thicknesses?

MR. GALLAGHER: So is your question about the torus or about the --

MEMBER WALLACE: Well, I find there are pits in the torus because you could see the torus.

MR. GALLAGHER: Right.

MEMBER WALLACE: We found pits. I just want to be somehow assured that there aren't pits in the drywell, which wouldn't show up in these random measurements.

MR. GALLAGHER: Let me turn that question over to Ahmed.

MR. OUAOU: Ahmed with Exelon. The corrosion sandbed region after we removed sand and cleaned up the sandbed region, we noted that the corrosion is primarily general corrosion. There were some --

MEMBER WALLACE: But you were able to look up the whole region.

MR. OUAOU: Absolutely.

MEMBER WALLACE: You didn't see pits.

MR. OUAOU: Well, there were localized areas and that's what this local criteria for acceptable thickness is for.

MEMBER WALLACE: You looked at part of the drywell and there was general corrosion.

MR. OUAOU: We looked at the entire surface of --

MEMBER WALLACE: Entire surface.

MR. OUAOU: -- of the sandbed region and the --

MR. GALLAGHER: From the exterior.

MR. OUAOU: From the exterior after the

sand was removed in '92 which I believe is going to come up in some slides but the corrosion is general corrosion, not pitting.

MEMBER WALLACE: You see, it would help really if you ask yourself the questions instead of us asking the questions. We asked these questions, this is how we answered them instead of us sort of having to drag it out of you. It would help.

MR. GALLAGHER: Okay.

MEMBER WALLACE: Maybe you could do that later on in your presentation.

MR. GALLAGHER: We will.

MEMBER WALLACE: Okay.

MR. GALLAGHER: Okay, so at this point, in the program, I'm telling you about how many UT points were developed in order to determine which monitoring points should be monitored. We also took core samples of the drywell shell to confirm these UT measurements. These core samples also confirmed that the degradation was general corrosion. At this point, in response to an NRC staff concern regarding whether the inspection locations represented the condition of the entire drywell, in 1990 Oyster Creek prepared a new random UT inspection plan designed to address the concern.

Inspection results using the new random

inspection plan confirmed the previous locations were representative of the thinnest locations in the drywell. One location at elevation 60 foot 10 inches which is in the upper drywell, was also added to the program to expand the monitoring of the thinnest locations. The NRC staff accepted this program in an SER dated November 1st, 1995. Next slide.

At this point, I'm talking to you about the corrective actions. Corrective actions were then developed and implemented in order to address the ongoing shell corrosion. First, the containment pressure analysis was revised to establish additional shell thickness margin for the upper drywell. The original primary containment design pressure of 62 psig --

MEMBER WALLACE: I'm sorry, I have another question because in reading these, I see that the basic approach was a buckling evaluation. Buckling to me means collapse by having a vacuum in the vessel. And yet, this is talking here about containment peak pressure. It seems that the concern is that it would collapse due to a vacuum rather than it would burst due to a pressure.

MR. GALLAGHER: Yeah, the upper drywell actually the controlling mechanism is membrane stressors. Below it it's buckling, in the sandbed region below it's buckling. So we had to --

MEMBER WALLACE: Don't you have vacuum breakers or something to prevent this kind of a vacuum forming in the drywell?

MR. GALLAGHER: Ahmed?

MR. OUAOU: The cause of buckling in this case is the refueling water. During outages, the cavity is full of water. It's actually the dead load that's imposed on the shell and not the vacuum.

MEMBER WALLACE: No, it's not a vacuum inside.

MR. OUAOU: We do have vacuum breakers but that's not the type of buckling.

MEMBER WALLACE: So it's not a vacuum, it's a dead load of water.

MR. OUAOU: That's right. It's a dead load of water plus the dead load of whatever else is attached to the containment.

MR. GALLAGHER: Okay, so as I said, the original analysis had a design pressure of 62 psig and it was generic to a GE Mark 1 containment design and included a 10-pound margin. Analyses were then performed to re-evaluate the drywell design pressure for the Oyster Creek drywell. Analysis demonstrated that following worst case design basis, loss of coolant accident, the peak drywell pressure would not exceed 38.1 pounds.

Additional margin was added to establish a design pressure of 44 pounds and this change was approved as Amendment 165 to the Oyster Creek technical specifications in September of 1993. The revised containment pressure was later utilized to determine the minimum acceptable drywell thickness and establish additional shell thickness margins for an area above the sandbed region. A detailed analysis was performed to determine the minimum acceptable drywell, shell thickness. The results of the analysis show that the minimum general thickness required to satisfy the ASME code above the sandbed region is controlled by membrane stresses, as I said, and buckling controls the minimum drywell shell thickness in the sandbed region.

The analysis used 0.736 inches general thickness in the sandbed region which satisfied the ASME stress requirements for all design based load combinations and applicable ASME safety factors. All actual general thickness measurements have met this criterion as I've said before. The focus of the remaining corrective actions to prevent water intrusion into the sandbed region, and to eliminate the ongoing corrosion. Activities such as applying sealing tape and strippable coating to the reactor cavity liner during refueling outages and improving the reactor cavity trough drain were performed. The sandbed region drains were cleared to improve draining at this time.

Originally the sandbed region was inaccessible. Access to the sandbed region was gained by creating access ports through the surrounding concrete structure. The sand was then permanently removed from the sandbed region since this was determined to be acceptable by the containment analysis. The corrective actions also included the removal of corrosion from the drywell exterior surface and the application of a protective epoxy coating on the drywell exterior surface.

MEMBER WALLACE: So there's no sand there now.

MR. GALLAGHER: Excuse me?

MEMBER WALLACE: There's no sand there now.

MR. GALLAGHER: There's no sand there now.

MEMBER WALLACE: So the function of the sand is no longer being performed.

MR. GALLAGHER: Ahmed, if you could explain the original function and why that was acceptable to remove.

MR. OUAOU: The BWR Mark 1 containments had a sandbed region to transition from the embedded region into the cantilevered portion free-standing region basically to reduce the stresses. It's a cushion. And the analysis that was done in 1991 and '92 time frame, concluded that it's not required. The shell by itself can handle the stresses. And for that reason, it was removed.

MEMBER ARMIJO: A quick question, are the access ports to the sandbed region still open that you can go in there and inspect?

MR. GALLAGHER: Pete, if you can just describe the access ports.

MR. TAMBURNO: The access ports are man ways in the concrete. They're approximately six feet long and we've installed boron bags when we're at operation. When we do our coating inspection we remove the bags and we send a man through the man way to do the inspections.

MEMBER ARMIJO: So is there one or many?

MR. GALLAGHER: There's 10.

MEMBER ARMIJO: So you can do a 360-degree visual inspection.

MR. GALLAGHER: Yes, sir. Again, I'm talking about corrective actions here in the early '90s. The corrective actions also included the removal of corrosion from the drywell exterior surface and the application of protective epoxy coating on the drywell exterior surface in the sandbed region. The concrete surface below the sandbed was shaped and coated with an epoxy coating to --

MEMBER WALLACE: Well, if it was 1.1 inches originally and it went down to .75 or something, there must have been about half an inch of rust on there.

MR. GALLAGHER: Yeah, the 1. minimum is .8 inches is where we are not.

MEMBER WALLACE: But the rust is bigger than the original steel, so there's

MR. GALLAGHER: There was corrosion products there.

MEMBER WALLACE: A large amount.

MR. GALLAGHER: Which probably contributed to the clogging in the sand. The concrete surface below the sand I'm talking about now, that was shaped and coated with an epoxy coating to assure that any inadvertent leakage would flow towards each of the five sandbed drains. The drywell shell at the juncture, and this gets to some of your questions about the embed, of the concrete floor was sealed with silicon to prevent --

MEMBER WALLACE: When you took the rust off, did you get a smooth surface or did you have to sandblast it or something to get a smooth surface that you could coat? Was it kind of pockmarked or how was it?

MR. GALLAGHER: Pete, can you answer the question?

MR. TAMBURNO: This is Pete Tamburno again. The area was not smooth. There was pockmarks. Certain areas were more -- had more general corrosion and some areas were better.

MEMBER WALLACE: So you cleaned off the -- smoothed it off?

MR. TAMBURNO: Yes, we cleaned off all the corrosion by-products using hand tools and we also inspected --

MEMBER WALLACE: That's grinding is it?

MR. TAMBURNO: No, sir, we used hand tools.

MEMBER WALLACE: Brushes?

MR. TAMBURNO: Brushes and that type of

thing and that was required because for the coating application. We also did some inspection -- we did inspections of all the areas that were noted to be deep.

MEMBER ARMIJO: Did you keep photographic documentation of the area after it was all cleaned up so somebody could actually look at those pictures?

MR. GALLAGHER: Pete, photographic documentation?

MR. TAMBURNO: Yes, we have some photographs of the condition of the coating. We have a video which we have presented to the NRC and we do have some pictures from our most recent inspection which was 2004.

CHAIRMAN MAYNARD: I think you were asking a question about pictures of corrosion.

MEMBER ARMIJO: Yeah.

CHAIRMAN MAYNARD: You said pictures of the coating.

MEMBER ARMIJO: Yeah, I just want to say, when they did the cleanup and everything was all nice and --

MR. GALLAGHER: Precoating?

MEMBER ARMIJO: Yeah, precoating, they document that and then --

MR. GALLAGHER: Precoating, Pete?

MR. TAMBURNO: We do have a few pictures of the vessel after cleaning of the corrosion byproducts but before coating.

MEMBER ARMIJO: Okay, so there's some.

MR. GALLAGHER: So the embed area is what we're talking about now. As I said --

MEMBER WALLACE: This is what you used to convince the NRC that using some sort of average was okay and that the pock marks weren't too deep and all that kind of stuff? These photographs are what you used?

MR. GALLAGHER: Well, there was some data from the outside, Pete, the exploratory data from the outside?

MR. TAMBURNO: We took the inspection -- after we removed the corrosion byproducts, we performed a visual inspection of 100 percent of the sandbed region and then we inspected through UT measurements, the thinnest we found. We then evaluated those thinnest areas in a calculation and compared them to the results of the GE analysis.

MR. GALLAGHER: So the embed, the drywell shell at the juncture of the concrete floor was sealed with a silicone to prevent water intrusion going forward into the embedded drywell shell. The potential for corrosion of the inaccessible embedded shell prior to this corrective action has also been assessed. The water that was in the sandbed region is not aggressive to concrete. Therefore, our assessment is that the corrosion of the inaccessible embed shell is not significant, since it is protected by the high alkalinity in concrete.

MEMBER WALLACE: Well, it was corrosive to steel. So once it got in there, it's going to eat its way in further, isn't it?

MR. GALLAGHER: Ahmed.

MR. OUAOU: The embedded shell is protected by the alkaline environment in concrete and that --

MEMBER WALLACE: And that counteracts the corrosive activities of the water?

MR. OUAOU: That does not counteract the corrosivity of water. The water was not corrosive. In order for water to be --

MEMBER WALLACE: I think it was corrosive because the shell corroded.

MR. GALLAGHER: Yeah, we're talking about the area at the concrete interface and below.

MEMBER WALLACE: It's the bottom of --

MR. GALLAGHER: Yeah, and -- yeah, but --

MEMBER WALLACE: Explain why this corrosion couldn't go any further.

MR. GALLAGHER: Right, where it was corroded was above that area where the wet sand was in contact with --

MEMBER WALLACE: You're convincing us it didn't go any further.

MR. GALLAGHER: That's correct, not significantly.

MEMBER WALLACE: You're convincing us not significantly or no?

MR. GALLAGHER: No.

MEMBER WALLACE: It doesn't go --

MR. GALLAGHER: That the corrosion would not be significant.

MEMBER WALLACE: Verbal arguments or something else?

MR. GALLAGHER: This is consistent with the GALL of embedded --

MEMBER WALLACE: GALL says it doesn't corrode?

MR. GALLAGHER: Embedded seal in concrete. If you meet certain criteria of the water not being aggressive to the concrete, it does.

CHAIRMAN MAYNARD: Okay.

MR. TAMBURNO: Can I just to make a comment, certainly the embedded portion -- do you have the slide with the embedded shell, John, please?

MR. GALLAGHER: We have a cross-section of that area, showing the embed and a skirt, the drywell skirt that's below it.

MR. TAMBURNO: What this slide shows is the sandbed, the area where we applied seal after 1992 and that shows, you know, the portion of the shell that's embedded in the concrete and then you have a skirt which is a support for the shell under construction. Certainly, we really can't say that there's no corrosion in the embedded shell. There could be corrosion. What we maintain is that the corrosion should be less than in the sandbed region because of the protection that the alkaline environment provides for the steel.

But in the case of the embedded shell, if you look at the elevation 8 foot 3 and the bottom of the sandbed is 8 foot 11, the corrosion should be limited to that area, and of course, the skirt could have some corrosion, but the skirt is not relied upon as a support after the concrete was poured.

MEMBER SIEBER: So this skirt goes 360

degrees around solid, so moisture would have to drill through that skirt to go under --

MR. GALLAGHER: That's one of the points we were trying to make is that the skirt does provide a barrier and if you look at the plate thicknesses, the plate thickness above, you know, where the skirt is and in sandbed regions is the 1.159 and then below that is where -- it's the thinner skirt, so we think that the -- because of, you know, the concrete as we described, that the corrosion in that area would be less significant than the corrosion that was experienced in the sandbed region and then we did the analysis assuming that plate was at a uniform thickness of .736. So we feel that's covered.

MEMBER ARMIJO: Just one thing; when you inspected that area right down where, you know, if you could install a seal, the silicone seal, you must have looked at it and was the corrosion worse or equivalent in that region right close to the concrete or was it less?

MR. GALLAGHER: Yes, Pete can answer that question.

MR. TAMBURNO: We did inspect that area during the repair activities in there and the corrosion in that area was no worse than -- than the worst areas above it.

MEMBER WALLACE: That doesn't say very much.

MR. TAMBURNO: So it was no better.

MEMBER WALLACE: It was no better, right?

MR. GALLAGHER: Yeah, so it was the same. But there you would expect it to be similar because the sand, the wet sand -- there was sand throughout so the sand was contacting that. What we're saying is below that interface, it would be less -- the corrosion should be less significant because of the concrete that's embedded in it.

MEMBER ARMIJO: And that's a debate, right? That's an ongoing debate.

MR. GALLAGHER: Well, we think we're consistent with the guidance that's in the GALL and --

MEMBER WALLACE: You replaced the seal, did you?

MR. GALLAGHER: We put that seal in.

MEMBER WALLACE: You put it in afterwards.

MR. GALLAGHER: Yes, this is the corrective action.

MEMBER WALLACE: Okay.

CHAIRMAN MAYNARD: I'd like to move on with the presentation.

MR. GALLAGHER: Yes, sir.

MEMBER SIEBER: I'd like to ask, beyond, in our package the last slide you have is Slide 28. You're referring to backup slides which should be made part of the record. So -- okay.

MR. GALLAGHER: Yeah, any slide we show, we'll put in.

MEMBER SIEBER: Okay, we'll I'd like to have copies of this.

CHAIRMAN MAYNARD: Yeah, I want to remind everybody, we still have the staff's presentation after this and we also have public comment time. I want to make sure we get a chance to get through this and we'll see where we need to come back to.

MEMBER WALLACE: I'm sorry, Mr. Chairman, I'm responsible for this. I want to really know what's going on though, I'm afraid, so I have to ask these questions, because the presentation doesn't tell me unless I ask them, but I'll try to be brief.

MR. GALLAGHER: Okay, so leaving the embed, the drywell shell in the sandbed region was then coated. The coating that was applied was application of a three-coat epoxy coating system consisting of one coat of primer and two coats of epoxy coating. Each coat was visually examined and dry film thickness measurements were taken to assure the proper coating thickness was achieved. The coating is a two-part 100 percent solid epoxy coating which is less susceptible to the degradation and moist environments. The coating was tested to qualify for emersion surface coating applications such as tank linings. The surrounding environment has stable temperature conditions resulting in lower thermal stresses being applied to the coating and therefore, provides close to an ideal service environment which will result if a very long service life.

MR. BARTON: Do you have any idea how long that coating would be good for, the epoxy coating?

MR. GALLAGHER: We can have Ahmed answer that question.

MR. OUAOU: There were some estimates done by our engineering and it varied from 10 years to 20 years. Recently we spent a lot of time talking to the vendor about the qualification of the coating and the feedback we're getting is that there is no guarantee for that coating, whether it is 20 years, 15 years, whatever. However, you can rely on your inspections to give you an indication whether you're approaching the end life of the coating. So the rigor inspection is the gauge as to when we think that coating is to get replaced or repaired.

MR. BARTON: And the inspections are how frequent, every 10 years?

MR. OUAOU: The inspection, we inspect every fueling outage. We look at it basically every refueling outage.

MR. OUAOU: Every other refueling outage.

MR. GALLAGHER: Our current program, and I'll go into this, our current program which we do -- there's 10 bays. We do two of the 10 bays every other refueling outage and going forward, we're going to insure we do 100 percent of the bays every 10 years.

MEMBER SIEBER: And what's your cycle length, two years?

MR. GALLAGHER: Two-year refueling.

MEMBER ARMIJO: So it's every four years you inspect two out of 10 bays?

MR. GALLAGHER: That's the current program. Going forward, it will be a minimum of three every other outage to insure that we cover the you know, 10 bays.

CHAIRMAN MAYNARD: Do you have a criteria that when you find degradation that you expand or you increase your frequency or expand the number you look at?

MR. GALLAGHER: Yes, Ahmed?

MR. OUAOU: Yes, in the future, we'll be performing the ASME IEE inspections for the coating. Which requires that if you perform an automatic inspection, you look at the coating and you find defects, you have to assess the other areas that you looked at if you're doing a sampling. So if we do find degradations, we would look at other areas in accordance with our corrective action process.

CHAIRMAN MAYNARD: And you have a criteria as to what constitutes degradation?

MR. GALLAGHER: Yes, in the inspection program.

MR. OUAOU: This is Ahmed. We do have criteria. We're using the criteria right out of the WE that's looking for blistering and flaking and cracking, et cetera, degradation of the coating.

MEMBER WALLACE: This slide would benefit from numbers. If the first bullet said .74 and the second bullet said .69 or something, it would help.

MEMBER SIEBER: Yeah, it sure would.

MEMBER WALLACE: Can you tell us what those numbers are, what the shell thickness needs to be and what it is? Are you going to tell us the numbers?

MR. GALLAGHER: I told -- I said there's various limits throughout for each plate and specifically for the sandbed region, the minimum thickness was .736 inches and the minimum -- that's the minimum general. The minimum local is .49 inches and we need those criteria. There's -- every plate has a --

MEMBER WALLACE: By how much do you meet them?

MR. GALLAGHER: The margins?

MEMBER WALLACE: Yeah.

MR. GALLAGHER: Pete, if you can answer the margin question.

MR. OUAOU: This is Ahmed. Let me try to answer the question. I think giving you a number would be not easy and the reason for that is, is that there is a cylindrical region has a different thickness in the sphere than the sandbed regions.

MEMBER WALLACE: Let's just talk about the sandbed.

MR. OUAOU: The sandbed region, the original thickness is 1.154 inches. The UT measurements indicate that we have minimum of .80 inches and --

MEMBER WALLACE: Average, yeah.

MR. OUAOU: Average, and the required for stress to meet ASME requirements is .736. Now, I remind you that those type of measurements are in two bays. It does not reflect the entire sandbed region.

MEMBER WALLACE: Okay.

MEMBER ARMIJO: You guys could really help us a lot. You submit good information in some of your documents. On page 5 of your June 20th submittal, you have a very good chart showing all the numbers for all the regions of the design thickness, minimum measured thickness, required thickness and margin. You know, maybe you've got a chart like that in your backup slides but it would save a lot of time if we just had those numbers.

MR. GALLAGHER: Yeah, we're sorry, we didn't present the numbers on the graph. We had, you know, provided all those to the staff and they reviewed those in detail. So we were trying to just give a summary.

MEMBER WALLACE: I'm really puzzled when I read the document though, because here it says, "The analysis conservatively assumed that the shell thickness in the entire sandbed region has been reduced uniformly to a thickness of .736 inches.

MR. GALLAGHER: That's correct.

MEMBER WALLACE: Well, that's less than the .80 inches you said.

MR. GALLAGHER: Right, that's --

MEMBER WALLACE: Since we're just teetering on the edge of what you need to make that thing pass the code.

MR. GALLAGHER: The .736 is what the analysis was run at so that's the minimum and the .8 is the lowest point we have. And so that's 64 mils --

MEMBER WALLACE: The words say that you assumed it had been reduced to this thickness.

MR. GALLAGHER: What was the input to the analysis to come up with --

MEMBER SHACK: That's sort of a limit to find out how low they could go.

MR. GALLAGHER: That's correct.

MEMBER WALLACE: That's what it means.

MR. GALLAGHER: That's what it means.

MEMBER SHACK: You start with the 44 --

MEMBER WALLACE: What I assumed it meant was that you measured .8 and you assumed to be conservative, that it really could be .736. That's not what you mean by this statement.

MEMBER SHACK: No, it means with a 44 psi design pressure, he needs .736.

MR. GALLAGHER: Right, right.

MEMBER WALLACE: That's what it means, okay. It was confusing to me.

MR. GALLAGHER: And then the other point I was trying to make about, you know, most of the locations are well above that .8 and many of them are close to the original plate thickness.

Again, I apologize for not providing that table, but --

MEMBER WALLACE: It's very strange that you assume the answer. You assume .736 and then do a study. I think you deduce .736 from the study.

MR. GALLAGHER: That was an input to the analysis.

MEMBER WALLACE: And it showed everything was okay?

MR. GALLAGHER: And then we showed that we had the proper safety margins.

MEMBER WALLACE: But it doesn't down that .70 might be okay, too, mightn't it?

MR. GALLAGHER: It could be, could be.

MEMBER WALLACE: Well, why didn't you vary the thing and see where you get into trouble? Well, you did. That's the .49 is that?

MR. GALLAGHER: .49 is a local minimum.

MEMBER WALLACE: Okay, how thin does it have to be before we get into real trouble?

MR. GALLAGHER: How low can we go below .736 average?

MEMBER WALLACE: Yes, yes.

MR. GALLAGHER: We have not analyzed that.

MEMBER WALLACE: You don't know? It might be .735 or something. I mean, these are obvious things to do.

MEMBER SHACK: No, no, he has to go back and redo his design pressure calculations again, but for 44 psi he can go to 736.

MEMBER WALLACE: He doesn't say that. He said he assumed the answer and then said it was okay. That's different from deducing it.

MR. GALLAGHER: It's probably poorly worded, but the -- that's --

MEMBER WALLACE: .736 was deduced from the design pressure?

MR. GALLAGHER: That's the way we did the analysis and Ahmed, he can --

MR. OUAOU: If I may, this is Ahmed. I'd like to explain how that .736 came about. Essentially, the time that the analysis was done, the measured thickness was .80 and because at that time --

this is back in '81, sand has not been totally removed, there was an estimate as to how much corrosion we're going to have between now and when the analysis run --

MEMBER WALLACE: Yes.

MR. OUAOU: -- and somebody came up with the idea, well, if we use .736 we ought to be conservative.

MEMBER WALLACE: Yes.

MR. OUAOU: And that value was used to come up with stresses and that satisfied ASME requirements.

MEMBER WALLACE: So you did not deduce it from a design pressure. You assumed it and found it was okay.

MR. OUAOU: Well, yeah.

MEMBER WALLACE: So it may be that .65 is okay. You just don't know.

MR. GALLAGHER: The minimum thickness could be lower.

MEMBER WALLACE: I'm really puzzled. You would really reassure the public if you would say, "We've done the analysis and we show that this would be good all the way down to .4". That would be great.

MEMBER SHACK: You mean with a 44 psi

design pressure I could go lower is what you're saying.

MR. OUAOU: Not in the sandbed region, we just said in sandbed region buckling controls so you reduce the pressure to 44 or whatever number, that will not change that. If the pressure had control, that's true, but since the buckling controls --

MEMBER SHACK: Okay, that controls the thickness of --

MR. OUAOU: Exactly, exactly.

MR. GALLAGHER: That's the way the analysis was done. We could -- you know, we could continue to do an analysis --

MEMBER WALLACE: The bottom line, they've got to get this straight, because this is your case, isn't it? You say we assume .736 to be conservative and we do an analysis at the reduced pressure for the containment.

MR. GALLAGHER: Right, but like Ahmed said it --

MEMBER WALLACE: And then we show that it's okay.

MR. GALLAGHER: Right, but like Ahmed said the --

MEMBER WALLACE: You have no idea how far you are from it being not okay.

MR. GALLAGHER: Well, we know where we are as far as the measurements we have and we have 64 mils of margin to that .736.

MEMBER WALLACE: Well, when you do that analysis, you come up with some critical stress or something, X. And that's less than Y where it has to be.

MR. GALLAGHER: Uh-huh.

MEMBER WALLACE: You must know something about how different those are.

MR. GALLAGHER: We have the safety factors, Ahmed?

MR. OUAOU: With that stress analysis and as far as the sandbed region, the .736 is minimum because using that thickness, using that thickness stress limits you get in shell are those allowed by the --

MEMBER WALLACE: Now, they're just on the borderline.

MR. OUAOU: They're very close.

MEMBER WALLACE: Okay, so you just happened to hit the borderline.

MR. OUAOU: With the applicable safety factors, exactly.

MEMBER WALLACE: That would help if you had said that in the beginning. Okay.

MEMBER ABDEL-KHALIK: What is the certainty band on the .8 inch measured value?

MR. GALLAGHER: Pete?

MR. TAMBURNO: Whenever we take the data, we do make some uncertainty calculations based on the number of data points. Typically, the uncertainties on those numbers are somewhere approximately between plus or minus 10 mils.

MEMBER ABDEL-KHALIK: Is this a 95 percent confidence level?

MR. TAMBURNO: Yes, sir, with 95 percent confidence.

MEMBER WALLACE: Would it be true to say you have no margin then? You had .8 and then you said, "Well, to be sure we'll assume it could be .736, and when we calculate that, the stresses are found to be right on the borderline of acceptability." That means there's no margin except in this .736 being less than .8. There's no margin in the calculated stress.

MR. GALLAGHER: The margin that we're saying we have is 64 mils.

MEMBER WALLACE: Say that again, 64 mils?

MR. GALLAGHER: 64 mils.

MEMBER SHACK: The difference between .8 and 736.

MEMBER SIEBER: You arrived at that by assuming a future corrosion rate.

MEMBER WALLACE: Well, that's what I said, if you have these slides that talk about thickness with margin, unless you tell us what the margin is, we don't know anything at all.

MR. GALLAGHER: Right.

MEMBER WALLACE: That's why I'm being so insistent about that.

MR. GALLAGHER: At this point in the presentation, we're talking about the corrective actions.

MEMBER WALLACE: Yeah, I know, but --

MR. GALLAGHER: And what I'm saying is going forward in the sandbed region, we've determined that the corrosion was arrested and so -- and we put the coating on. So the visual inspections we performed on the coating verified that no ongoing corrosion is taking place. So we are, you know, flat-lined in the sandbed region as far as corrosion and just, you know --

MEMBER WALLACE: I have to decide whether or not deducing stresses which are on the borderline of acceptability is okay? Is that what I'm asked to decide?

MR. GALLAGHER: I guess I don't understand your concern because --

MEMBER WALLACE: Well, I understand it very well.

MR. GALLAGHER: The -- as with any analysis, you have -- you determined what the minimum and there will be safety factors with that. So with the appropriate safety factors, we're saying we need to be above .736. We've said that --

MEMBER WALLACE: You just make it, right?

MR. GALLAGHER: Well, there's 64 mils of margin and the corrosion has been arrested.

MEMBER WALLACE: 64 mils of margin, that's pretty --

MR. GALLAGHER: The corrosion has been arrested and it's coated --

MEMBER WALLACE: Because it's .8, okay.

MR. GALLAGHER: And it's coated.

MEMBER WALLACE: Well, I thought you were saying .8 might not be really accurate, so we'd assume it's .736. Okay.

CHAIRMAN MAYNARD: Well, the code has some conservatism in it, too, does it not?

MR. GALLAGHER: Yes, the safety factors that we have in there.

MEMBER BONACA: Yeah, the concern I have is not the specifically but at some point you'll address it too, I imagine. You made other commitments regarding corrective actions and mitigative actions and so on as a -- and then, you know, at the same time as you make these commitments in writing and that are reported in the SER, you had water in jugs out there and you didn't even test it as you were supposed to do. Could you tell us about that? I mean, I'm still left with this question, are we talking about hypothetical things or are we talking about what's happening out there? How can we trust a program that you claim was in place since 1990s and then it wasn't in place when the inspection occurred?

MR. GALLAGHER: Yeah, do you want me to address that issue right now?

CHAIRMAN MAYNARD: Might as well, yes.

MR. GALLAGHER: Okay, so as far as the water in the bottles, let's step back and talk about that for a minute. First of all, our overall program which I haven't got into yet on the initial aging management program, relied on monitoring UT's in the drywell area for the corrosion rate, to determine the corrosion rate and we determined these corrosion rates were very low and then our ongoing coding inspections. So we have, you know, fulfilled our commitments associated with managing the aging and the drywell.

Now, the water monitoring, we should have been performed more rigorous water monitoring and one of the things we identified when we were developing our commitments for implementation for the license renewal application, was that we had not been rigorously performing the water monitoring. In March of this year, when we did a walk-down of the torus rim from those sandbed drains, as we described there's five sandbed drains. There's tubing that goes from those sandbed drains to these water jugs, they're like five-gallon water jugs. There was some water in there. We believe that water is very old and we believe that if there was any active leak, which we verified at the time that there was no active leak, the tubing was dry and that type of thing, if there was an active leak, incidental observation would have identified that as a concern and then we would have taken corrective action.

MEMBER BONACA: But you have no --

MR. BARTON: But you're telling us that nobody observed water that's been there for a long time in the torus area that's collecting water from the sand pocket drains, right, and nobody paid attention to that or said, "Why is there water in here"? I mean, you're saying it's old water. So for a long time nobody gave a hoot about this commitment.

MEMBER BONACA: And what bothers me is here you have, you know, the shell is down to minimum margin, okay, and I grant it from you. I'm not going to question this point. And so you would want to see most aggressive actions to preserve the margin which means delivering only commitments which says if there is water, we're going to remove it within three months and so on and so forth.

Furthermore, I mean, you don't have record of whether or not used a strippable tape. So you're still not dealing with the source of the whole problem which is these cracks up there in the refueling cavities. So I'm saying, since you haven't done it yet, why am I to believe that you'll do it in the future once we -- once you get to the operating license for 20 more years? I mean, that's an important issue.

MR. BARTON: And also, isn't it standard practice if you see water someplace in a container on the floor or something that you sample it and see where the hell the source is from before you throw it away?

MR. GALLAGHER: That would have been helpful. In this case --

MR. BARTON: Would have been helpful? It should have been required. I mean, what kind of practices do we got at this site these days where you have something like that and people get rid of it and nobody cares about what it is or where it came from. That doesn't tell me a hell of a lot about what's going on at this site cultural-wise.

MR. GALLAGHER: Yeah, the thought process behind removing the water was to determine if there was actively leakage going on. As far as commitments, I can give you to Tim Rausch, he's our Site Vice President and later on in our presentation, we do have how we've, you know, tracked commitments, what we do now, and how we insure they get done. Tim?

MR. RAUSCH: Yes, good afternoon. I'm Tim Rausch, Site Vice President. In response to the question regarding the commitments and the integrity of meeting those commitments, there was a period of time in a transition of the station, in terms of ownership and the commitments were not rigorously upheld during that period of time.

MR. BARTON: They weren't what?

MR. RAUSCH: They were not followed through on.

MR. BARTON: You make a commitment to the NRC. You've got a commitment tracking system and you ignored it.

MR. RAUSCH: Yes, the commitment tracking system for the particular commitment regarding the water into the bottles and the monitoring of that was a deficiency on our part in terms of the performance and we acknowledge that in the exit -- of that AMP exit that was conducted several weeks ago. So the commitment that we have going forward is this company has a formal commitment tracking system. It's automated with backup barriers to insure that those commitments are, in fact --

MR. BARTON: Is that a brand new system?

MR. RAUSCH: Well, it's not brand new but it is an excellent system that is being implemented.

MR. BARTON: What happened to the old GPU commitment tracking system? Did you throw that out?

MR. RAUSCH: No, sir.

MR. BARTON: Well, wasn't it in that commitment system was well?

MR. GALLAGHER: This -- if I can answer

that, Mr. Barton, the specific commitment was in correspondence.

MR. BARTON: Right.

MR. GALLAGHER: And we have not found any specific implementation document that implemented that commitment from after it was made by GPU in the early '90s.

MR. BARTON: So nobody took that correspondence from the NRC and put it in the commitment tracking system.

MR. GALLAGHER: That's what it looks like and now, we know that it was done and it was done by the project personnel assigned to that and it was done for a long period of time. I think it was one of those things that was owned by, you know, high ownership and they just did it but it was not embedded in any, you know, rigorous process. Right now, we have it as a specific preventative maintenance task specifically scheduled and it will get done and it's been done five times to date and there's been no water detected in those drains.

MEMBER BONACA: Well, I mean but, you know, the commitments report in the SER were in response from you on June 20th of this year and the findings from the inspections that defeat those commitments were in September.

MR. GALLAGHER: The inspection actually was in March and we had, ourself, identified this water issue in the bottles.

MEMBER BONACA: All right, I didn't --

MR. GALLAGHER: And it was during the inspection in March also and the inspection exit was not until September.

MEMBER BONACA: All right.

CHAIRMAN MAYNARD: I know the questions are important. I would like for you to go ahead and get through your presentation. We also have the staff to question on a number of these things as to why do they find some of these things acceptable and if need be, we can bring the licensee back up here and --

MEMBER WALLACE: Let me tell you what I'm thinking. I've asked myself the question, are these folks ready to go forward to the full committee. They don't always do that. This is a subcommittee, right?

CHAIRMAN MAYNARD: Right.

MEMBER WALLACE: We don't always recommend that they are ready to go forward. It's not as if the schedule has to be always met. So you have to develop some credibility. So I guess that's what I'm after here is getting enough credibility to go forward.

That's why I'm asking these questions.

CHAIRMAN MAYNARD: And I fully understand.

MEMBER WALLACE: If I don't have it, I'm going to have to say, I'm going to have to have another meeting or something. So that's why I'm asking.

CHAIRMAN MAYNARD: I fully understand that and that may be one of the options, you know. Again, we won't end this meeting until we've either got the questions answered or that we --

MEMBER WALLACE: Yeah, you want to see more of what they have to say.

CHAIRMAN MAYNARD: Right, or we may very well determine that we need another subcommittee meeting before trying to go to the full committee. I would not recommend going to the full committee until we've --

MEMBER WALLACE: I've looked at the rest of the slides. I think they can move quickly.

CHAIRMAN MAYNARD: Yeah, if we can get through theirs and also the staff's and hear the public, then I think we'll be in a better position to make some of those determinations.

MR. RAUSCH: Mr. Chairman, may I just finish the comment in terms of the commitment. The company of Exelon/Amergen understands how the commitment was met at this time and it has taken corrective actions to insure that doesn't happen again in terms of addressing the question of how can we feel confident going forward that we won't have a similar occurrence. Thank you.

MR. GALLAGHER: Okay. I believe we're on Slide 15 now, which --

MEMBER SIEBER: Before you escape from this slide, I do have a question. You talk about taking UT measurements, thickness measurements of the shell. And it was stated that the corrosion of the shell was not uniform and, therefore, when you take individual point measurements, even in a grid or the thousand measurements that you talked about on the previous slide, there is some probability that there is a thinner place than what you've measured. And so, you can't just assume that here's the minimum thickness I can tolerate to withstand the pressure of the -- the accident pressure. You have to have some margin that's statistically based between your minimum measured thickness and the minimum or the minimum allowed thickness for the pressure. Have you done that work and has the staff reviewed it?

MR. GALLAGHER: Pete?

MR. TAMBURNO: Yes, we've done that work. We've taken the data for the upper regions and applied a 95 percent confidence intervals on the data and also in the sandbeds.

MEMBER ABDEL-KHALIK: How about the embedded region?

MR. TAMBURNO: The embedded region has not been inspected.

MEMBER ABDEL-KHALIK: So do you have confidence that the thickness in that region will be greater than .8 inches?

MR. OUAOU: This is Ahmed with Exelon. We have confidence that the corrosion incentive bed region and the embedded region it will not be greater than the sandbed region itself. And since we use the same analysis and the same minimum thickness, we believe that balance the potential of having corrosion in the embedded region. And --

MEMBER ABDEL-KHALIK: Where does your confidence come from?

MR. OUAOU: We have consulted with corrosion experts. We looked at the environment that the embedded shell is going to be subjected to. Based on that, our consultants indicated that the corrosion in the embedded shell will not be greater, should not be greater than the sandbed region area.

MEMBER SHACK: Well, that's certainly true from when you had active ongoing corrosion in the sandbed. You know, I'd fully accept that argument that it would be less. Now, that you've arrested the corrosion in the sandbed, what's your assurance of the environment within there. That really comes down to the integrity of the silicon seal.

MR. OUAOU: And in response to that question, we agree with you. The fact that the seal itself now protects the embedded shell. We inspect the seal with we inspect the coating mixture of that it is not cracked or it is not damaged such that any potential moisture will get in the embedded shell.

MEMBER SHACK: And there's no other access path for water to that embedded region.

MR. OUAOU: No.

MEMBER WALLACE: This 95 percent confidence seems to me an important issue. If you do a statistical analysis, it should be part of your presentation. It's a good piece of evidence and it should be there. We shouldn't have to drag it out of you and it should be explained fully so we know what it was. Is it a confidence that the thickness is bigger than .736 where there's 95 percent probability and blah, blah, blah, or is it bigger than .72 or what it is? Give us the numbers, otherwise it's all vague.

MEMBER ARMIJO: Well, I'd like to add that your Table 1 in your June 20th letter to the NRC shows that in the embedded region you have almost three times as much margin for the lower sphere even if you assume that that region which you couldn't inspect, corroded down to .8 inches. And you know, again, beating a dead horse on this table, but this table is very informative. I got a lot out of it. I wish we could all have had it in the presentation.

MR. GALLAGHER: Okay, a point well-taken. We'll -- I again apologize for not having that in there.

Okay, if we could move onto Slide 15 then, which at this point in the presentation we've put the corrective actions in place and then after the corrective actions were implemented, the effectiveness was then determined. And we took UT thickness measurements in 1992 and again, in 1994 in the sandbed region and confirmed that the corrosion in the sandbed region had been arrested. UT measurements were also taken in 1996. However, there were some anomalies in this data. In some cases, the values were greater than previously measured.

We investigated this and determined that the most likely contributor is attributed to not removing a protective grease coating prior to taking the measurements. Corrective actions are in place to prevent this from happening in the future. These sandbed UT measurements will be performed in the refueling outage that begins this month.

Also at this time to verify the effectiveness, we did the coating inspections of the applied coating to the sandbed region and that was visually examined and determined to be acceptable. If we go to Slide 16, so now we're at the stage of our initial aging management program. And the initial aging management program that was established primarily consisted of the upper drywell UT measurements and the sandbed region coating inspections. The UT measurements in the sandbed region were discontinued because the corrosion was determined to be arrested and since the sandbed region was now accessible, the visual inspections of the coating were determined to be a more effective inspection.

Every other refueling outage, the upper elevation UT measurements have been performed. These measurements are verified to be greater than the minimum required plate thickness and a corrosion rate is projected to verify the acceptability of continued operation. The results indicate that there's no ongoing corrosion at the two elevations and that the corrosion rate for the other three elevations are less than one mil per year. The service life of the drywell extends well beyond 2029 with margin.

MEMBER WALLACE: Is this all based on some sort of statistics or just measurements?

MR. GALLAGHER: Pete?

MR. TAMBURNO: It's based on the 95 percent confidence intervals around the curve fit of the data.

MR. GALLAGHER: Since the exterior surface of the supper drywell is not accessible, these UT's were continued. Additionally since the exterior surface of the drywell shell above the sandbed region is not epoxy coated, the corrosion rates identified are the leading indicators of corrosion overall in the drywell. The coating applied to the sandbed region of the drywell shell exterior has also been visually examined, two of the 10 bays have been examined every other refueling outage. Some of the bays have been examined multiple times because those bays contain the thinnest shell locations.

A total of five of the 10 bays have been inspected to date. All coding inspection results have been satisfactory. When we get into our future program I'll show you that we are going to look at those other five bays and then again all 10 bays every 10 years. Next slide.

As part of the preparation of the license renewal application and subsequent NRC review, the drywell shell aging management program has been enhanced. The following are the key elements of our aging management program. Amergen will continue to apply the strippable coating on the reactor liner, reactor cavity liner each refueling outage prior to filling the reactor cavity with water. We will also insure that the reactor cavity trough drains are clear. These actions will eliminate water intrusion into the sandbed region.

Sandbed drain leakage monitoring is performed quarterly during non-outage periods and will be performed daily during the refueling outage when the reactor cavity is filled with water. These are the more rigorous inspections that I'm telling you we have now through our preventative maintenance tasks. Corrective actions will be taken if further water leakage is identified. The upper drywell shell UT's will continue to be taken every other refueling outage. Again, these measurements are the leading indicator of -- for corrosion, overall corrosion in the drywell.

Amergen will perform periodic confirmatory UT inspections of the drywell shell in the sandbed region. The UT measurements will be taken prior to entering the period of extended operation and then after four years. After confirming that the sandbed region corrosion continues to be arrested, the frequency would then be extended to 10 years thereafter. The NRC will be notified within 48 hours of any unexpected results and corrective actions will be taken.

MEMBER SIEBER: If the coating fails right after you do an inspection, how long will it take for corrosion to take you below min wall, four years, or have you done that?

MR. GALLAGHER: Pete, did you get the question?

MR. TAMBURNO: This is Pete Tamburno. At the current projected corrosion rates that we've seen in the upper regions, a four-year -- it would take much longer than four years.

MEMBER SIEBER: Even uncoated?

MR. TAMBURNO: Yes, sir.

MEMBER BONACA: How do you justify 10 years?

MR. GALLAGHER: The 10-year inspection rule for the coating?

MEMBER BONACA: Yeah.

MR. GALLAGHER: Ahmed?

MR. OUAOU: The 10-year inspection of the coating is based on ISI ASME Section 11 but I think one thing that's important to mention is that we are actually doing or staggering the inspections during refueling outages such that we've been looking at three, I believe --

MR. GALLAGHER: Right, a minimum of three bays every other outage.

MR. OUAOU: -- minimum of three bays every other outage.

MR. GALLAGHER: For the sandbed region coating prior to the period of extended operation Amergen will perform a visual inspections of epoxy coating of the five bays that have yet to be inspected.

MEMBER SHACK: I hate to interrupt. How extensive is this inspection going to be before you enter the period of extended operation? You look at all the bays?

MR. GALLAGHER: There's five bays that we have not yet inspected. We were going to look at all five of those and -- with our inspection program.

MR. BARTON: This outage?

MR. GALLAGHER: We are doing them this outage. The commitment is prior to the period of extended operation.

MR. BARTON: So not much time.

MR. GALLAGHER: We have to start this month.

MEMBER BONACA: So, really, I mean, you have some substance there. I mean, you don't know what you're going to find.

MR. GALLAGHER: We've -- based on the inspections we've done before, the coating has been you know, satisfactory. In addition, as I said, we'll inspect 100 percent of the epoxy coating every 10 years during the period of extended operation. So Slide 18.

So our overall conclusions on the drywell corrosion at Oyster Creek are, the corrective actions to mitigate the drywell shell corrosion have been effective, the drywell shell corrosion was arrested in the sandbed region and continues to be very low in the upper drywell elevations. The service life of the drywell shell extends beyond the year 2029 with margin. And we have an effective aging management program to insure continued safe operation.

MR. BARTON: This every 10 years is only going to get you one inspection during your extended period of operation.

MR. GALLAGHER: For which --

MR. BARTON: In drywell region, drywell coating visual every 10 years, it gets done in 2009, are you going to do in 2019, 2029, you're done, you weren't going to do one anyhow. So you're going to do one of them in 20 years.

MR. GALLAGHER: Are you talking about the coating inspection, sir?

MR. BARTON: That's what is says here.

MR. GALLAGHER: Okay, what we're doing is, Ahmed had mentioned, we are staggering the inspections, so every other outage, we're going to do at least three bays.

MR. BARTON: And every 10 years, you're going to have done --

MR. GALLAGHER: 100 percent, yes.

MR. BARTON: -- 360 degrees.

MR. GALLAGHER: That's correct. So we'll

do it twice in the period of extended operation.

MR. BARTON: I gotcha now.

MR. GALLAGHER: Okay.

MEMBER WALLACE: I think it's flexible. If you found some problem with the three bays, you might then go back and inspect some more bays.

MR. GALLAGHER: That's correct. If we find a problem, we would have to do an extended condition and we would increase our inspections.

CHAIRMAN MAYNARD: That's what I'd asked about earlier is criteria for if we find something, expand and more frequent --

MR. GALLAGHER: We've also -- I've just given you some of the key issues -- key commitments in our aging management program. There's also other ones particularly if we did find water say in the water drains, we would do further inspections of the coatings from those bays. So there's other features in our program you know, to insure that issues that are not expected are pursued and evaluated.

This slide, Slide 19, shows the five open items from the Draft Safety Evaluation Report and to close the first item we are committing to additional inspection locations at the two plate transitions on the shell and so this will be a total of four. We had one inspection for each of these transition plates. We are going to increase that to four locations at each of these two plate transitions and we will be submitting additional correspondence on this issue.

Based on discussions with the NRC staff, we believe no additional information is needed from Amergen on the other four items. So that concludes the drywell corrosion. Are there any more questions on the drywell corrosion before we go onto the rest of the presentation. I'll ask the Chairman if --

CHAIRMAN MAYNARD: We may have some more questions. What I'd like to do is get through the presentation. We'll have a number of questions for the staff, and I'm -- as long as Amergen is staying here, then after the presentations, if we have additional questions at that time, we can come back to some issues.

MR. GALLAGHER: Okay. All right, so I'll now turn it over to Fred Polaski who will discuss some of the key historical equipment issues and how they're addressed and the results of our license renewal application.

MR. POLASKI: Thank you, Mike. I'd like to briefly discuss the history and status of other significant plant equipment problems that have occurred at Oyster Creek. All of these issues are well-understood and ongoing activities monitor these issues as part of the Oyster Creek Corrective Action Process. First of all, what I'd like to talk about is the core shroud. In 1994, a significant circumferential crack was identified in the H4 weld. Ten tie rods were installed to provide full structural repair for the horizontal welds. Since then inspections have not detected any significant indications or cracking in the shroud.

In 1978 a crack was identified in one of the core spray spargers. In the upper sparger there was a 180-degree crack around the circumference of the pipe. A mechanical clamp was installed. In subsequent refueling outages multiple indications were observed and nine additional clamps were installed for a total of 10. And of these 10 four of them were on all of the T boxes and they're all clamped. Subsequent inspections and testing indicated there really are only two confirmed indications that result in leakage through the dispargers. The root cause was determined to be high residual stress from installation of dispargers.

In 1991 a crack was observed in the top guide of the reactor vessel. Subsequent inspections identified further cracking and in 1996, a 100 percent UT examination was performed of the top guide and confirmed that there's six cracks in the top guide. Metal samples confirmed that the reason for the cracking was a radiation assisted stress corrosion cracking. These cracks are monitored during refueling outages and no new growth has been observed since the year 2000.

MEMBER SHACK: And your water chemistry is?

MR. POLASKI: The chemistry is good and it's hydrogen water chemistry since 1992.

MEMBER SHACK: With noble metal or just --

MR. POLASKI: Noble metals in 2002.

MEMBER ARMIJO: Do you attribute the lack of new IGSCC cracks to the water chemistry?

MR. POLASKI: Water chemistry is a major influence on IGSCC cracking. With the proper water chemistry you shouldn't have any IGSCC. And getting ahead a little bit but I'll cover this, that the hydrogen water chemistry implemented at Oyster Creek is greater than 99 percent availability during the last cycle. The injection rates are such that they obtain a molar ratio of four to one. BWR VIP recommends at least three to one, so four to one is and no additional growth in the last -- you know, since 2000.

MEMBER ARMIJO: Do you have a noble metal monitoring system?

MR. POLASKI: Noble metals are injected in 2002. There is a hydrogen water chemistry monitoring system.

MEMBER ARMIJO: So you measure potential and --

MR. POLASKI: Yeah, you measure potential to keep your minus or less than minus 230 millivolts.

The next thing I wanted to discuss was CRD stub tubes. Two of them were found to be leaking in 2000. They were repaired by -- and this was observed during the hydrostatic tests at the end of the refueling outage. They were repaired by performing a roll expansion of the CRD housing. They're inspected every outage when the drywall is accessible and no subsequent leaks have been observed.

MEMBER SHACK: Just my own curiosity and how reliable is your ECP measuring system? What's its online availability?

MR. POLASKI: I'm going to ask Marsha or Terry Schuster to answer that.

MR. SCHUSTER: Terry Schuster, Chemistry

and Environmental Manager for Oyster Creek Station. The ECP probes are continually available in the Bravo recirculation loop. Our measured millivolt reading is minus 400 millivolts for the ECP probes and that is lower than the expected minimal value of minus 230 millivolts and that has been consistently the case for the entire cycle.

MEMBER SHACK: This is copper, copper oxide?

MR. SCHUSTER: I'm sorry, I don't know the makeup of the probe but it is available and it measures good results continually.

MR. POLASKI: The other reactor vessel and thermo component I just wanted to briefly discuss was the steam dryer. I know that's been an issue in previous license renewal applications. Oyster Creek inspections have identified some minor cracking. However, it's not been extensive and been repaired. The Oyster Creek steam dryers are a different design than the one at Quad Cities and Dresden. It's a more robust design. There have been no power uprates performed at Oyster Creek and none are intended so we don't have any of the flow problems and vibration problems that they had at Quad Cities and we don't believe it's going to be an issue for license renewal.

MEMBER SIEBER: Is it in scope?

MR. POLASKI: Yes, it's in scope. And we will be implementing the BWR VIP inspections on it but don't expect any problems with it right now. The other thing is too, and I already talked about hydrogen water chemistry in noble metals. In implementing inspection procedures for the reactor vessel internals are all done in accordance with the BWR VIP program, so we're following that program.

The next thing I wanted to talk about, a total different subject, medium voltage electrical cables. There have been a history of failures of these cables in wetted environments at Oyster Creek. Most was determined to be susceptible cables due to design insulation type and manufacturing issues. Presently replacement cables that we're using are Okenite EPRI cables which are designed for wetted environment conditions. We've had no failures of these type cables since they've been installed.

And in the refueling outage later this fall, the four known susceptible cables are going to be replaced with Okenite EPRI cables.

MR. BARTON: And this cable can withstand a wet environment, the new one?

MR. POLASKI: The new ones, let me just

double-check, Dan Barnes or Debby, are these in wetted environments? Yes, the answer is that these four are in wetted environments.

MEMBER BONACA: They're qualified for it.

MR. POLASKI: Pardon?

MEMBER BONACA: The replacements are qualified for wetted environment.

MR. POLASKI: Yes, they're designed for wetted environments.

We've performed continuing testing of cables and we have two types of testing we do. For accessible shielded cables, we do online partial discharge testing. And for cables that are either unshielded or not accessible to be tested while they're online, we do step voltage and power factor testing when the lines can be determinated.

CHAIRMAN MAYNARD: I noticed, it looked like for your inaccessible or underground medium voltage cable, you were committing to a test methodology that hasn't been approved yet but you anticipate it being approved before the period of extended operation.

MR. POLASKI: What we committed to in the application was an aging management program that's consistent with the GALL program. We have a vendor that we've been using for several years to do testing and that methodology has been submitted to IEEE and is going through reviews right now. We believe it's going to be an acceptable method to go forward in the period of extended operation and we've used it and it has indicated degradation of cables and that's been confirmed in one or two cases when the cables have been replaced.

CHAIRMAN MAYNARD: I'll save the rest of mine for the staff when they get to acceptability.

MR. BARTON: Has there been any work done on site to either minimize or eliminate the water intrusion into the conduct system?

MR. POLASKI: Well, one thing that has been done is some of the cables have been rerouted so they're not in locations that would be susceptible to water and that's really about the only thing you can do where you've got cable that's in conduit underground. I mean, there's no way to prevent water from getting into that conduit.

MR. BARTON: So you have rerouted some of those.

MR. POLASKI: We have rerouted some of those, but not all of them.

MR. BARTON: Do you intend to reroute the rest of them or are you going to rely on the Okenite cable?

MR. POLASKI: Right now, the plan is to rely on mainly the Okenite and the ongoing testing where we should be able to detect any degradation, I mean, because this cable testing is designed to look for water issues and detect it, see it coming and be able to replace it in time before it would fail.

MR. BARTON: Or it bows, okay, thank you.

MR. POLASKI: Any other questions on that? Okay. The next topic, I'd like to discuss is underground piping. There have been leaks in underground piping at Oyster Creek due to salt water corrosion from the inside of the pipe after failure of the internal coatings. We've not have any failures from age-related degradation of the external coatings of this piping.

MR. BARTON: Wait a minute, hasn't there been any failures of water piping from coatings deteriorated during installation?

MR. POLASKI: There was one with a problem with installation problem of the coating but none of that's been age related where it's degraded over time. And that one was fully investigated and it was determined to be an installation problem that occurred.

MR. BARTON: And hopefully that's the only installation problem that -- that piping coating was damaged, all right.

MR. POLASKI: The only way to determine if there's any other ones is to dig it all up and look.

MR. BARTON: I know you can't do that, I understand that.

MR. POLASKI: That probably would cause more problems than if you'd just leave it alone.

MR. BARTON: I understand that. In your underground piping program, though, is the diesel transfer piping from the main storage tank to the diesel generator building included in that program, because I couldn't find reference that that was or that fire protection piping was included?

MR. POLASKI: I'm going to ask Pete Tamburno to answer that question.

MR. BARTON: The one that had a leak in it years ago.

MR. TAMBURNO: This is Pete Tamburno. We're replacing the diesel fuel transfer line presently. Right now, the project is about 70 percent due and -- 70 percent complete and it should be done by the end of the year. The fire protection system has been added to the program and will be inspected as part of our license renewal commitments.

MR. POLASKI: Thank you, Pete. What I wanted to continue on was the site has an existing ongoing underground piping program that was in place before we started to prepare the license renewal application, where they've looked at all the underground piping and which is the most significant and risk impact to the plant. They have replaced 50 percent of the underground safety-related emergency service water piping and the remainder will be replaced prior to entering the period of extended operation. The non-safety related service water piping is being replaced with a phased plan as part of this underground piping program.

And the aging management programs in place at the plant that enhanced as part of the license renewal process to inspect all the in-scope buried piping before we enter the period of extended operation. In summary, we believe that our existing aging management programs have been successful in managing aging for these issue and will be continued into the period of extended operation and will be successful for the next 20 years.

Slide 21. Our license renewal application was submitted July 22nd, 2005. In the time period when we were preparing that license renewal application, I realized in my work with NEI licensure task force and interfacing with the NRC that the NRC was revising the Standard Review Plan in the GALL report and that the new versions of that would be issued in September 2005 and would be used by the staff for their review of the application. And I was concerned that if we prepare the application using rev 0 of the GALL and standard review plan, which were approved in 2001, that there would be a large number of differences identified during the review by the staff.

So we discussed this issue with the staff and obtained their concurrence that for preparation of the Oyster Creek application, we would use the draft revision 1 of the GALL and the Standard Review Plan which were issued in January of 2005 and the NRC expected that there would be few changes between the draft and the final versions of rev 1. We also, in preparation of the application, used NEI 95-10, the guidance document and we used the latest revision on that. Ultimately, we're using rev 6, which was issued in June of 2005.

This approach worked well for us and for the NRC. After rev 1 was issued, we performed a reconciliation of the final version versus the draft. We looked for changes and additions to aging management programs. We looked at the GALL line items to determine if there were any of those that changed from the ones we'd used for Oyster Creek, any had been deleted or whether there was any new line items that we would have used if it had been available when we prepared the application.

The result of that, we identified that four new inspections or enhancements to existing inspections were needed. There was five new exceptions to programs which we reconciled and actually two of the exceptions we had identified in the application was eliminated because of the update to the application. So overall, very few changes were needed as a result of going to the new version of GALL and Standard Review Plan.

The last thing I'd like to mention in this area is that the NRC's schedule and process for review of our application consists of two audits on site but the License Renewal Group, one for aging management programs and one for aging management reviews. During the first audit in October of 2005, it was recognized by the NRC and Amergen that the backup information that we had available for review by the NRC was not in a format that facilitated an efficient review by the staff. We made a decision then we would prepare basis document notebooks similar to those used by other applicants to support the future reviews and the audits were held successfully in January and February of 2006.

Slide 22. We identified for Oyster Creek in our application 57 aging management programs, 50 of those that align with the GALL programs and seven were plant specific. Of the GALL programs, 32 were existing programs, 14 of which required some enhancements and we had 18 new programs. I'd like to mention about that 18 just a little bit that it's a lot larger number than you would typically see, I think, in recent applications, the reason being is that our Forked River Combustion Turbines which are alternate AC power supply with station blackout were in scope of the rule. We prepared aging management programs specifically for them that were separate and different than the corresponding programs to the plant. For example, in the cooling water aging management program we have one for the Oyster Creek plant. We have a different one for Forked River Combustion Turbine.

MR. BARTON: Why was that separate and submitted late?

MR. POLASKI: I was going to get to the point of late. I'll get to that in just a minute when I get into combustion turbines. The reason we did it separate, I'll get to that whole thing in a minute, yeah.

MR. BARTON: Okay, that's fine.

MR. POLASKI: So 11 with Forked River and one also dealt with our meteorological tower and the reasons I'll get to in a second.

MR. BARTON: Okay.

MS. POLASKI: And seven plant specific, four existing and three new, again one with the Forked River Combustion Turbines.

MEMBER SIEBER: Who is going to do the programs for the combustion turbine?

MR. BARTON: He's going to get to that later.

MR. POLASKI: I'm going to get -- Slide 23, the next slide.

MEMBER SIEBER: First Energy, right, how are you going to make First Energy do it?

MR. POLASKI: Okay, so for everybody's understanding, Forked River Combustion Turbines are two peaking combustion turbines rated at 30 megawatts each. They were installed by GPU in 1989 in the Oyster Creek Substation. As a result of having to comply with the station blackout rule, in 1992, these were credited as the alternate AC power supply. Breakers were installed and transmission conductors will be able to tie those into the plant. I will note that only one of the two is needed to meet the station blackout design.

MEMBER SIEBER: Is one of the two committed to the SBO or are they both committed?

MR. POLASKI: They're both committed to station blackout but they have to make sure that one is always available and one would be provided during station blackout conditions.

MEMBER SIEBER: Okay. In reality, even though they're 38 megawatts, I think our transformer limitation is something like four megawatts we could take off of those. So we only really need and could only use one of them. They are currently owned and operated by First Energy. So that -- you know, the question is, how are we going to maintain them? They are covered by the Maintenance Rule and surveillance testing programs and as part of the station blackout design, we monitor reliability of the those.

On Slide 24 --

MR. BARTON: That means you've got a systems engineer that makes sure everything First Energy does is in accordance with your maintenance rule?

MR. POLASKI: That is correct.

MEMBER SIEBER: Or doesn't do.

MR. BARTON: Or doesn't do, yeah.

MR. POLASKI: Well, it does to it. The reliability is greater than 99 percent. In fact, I think the number is like 99.92 percent for the last 100 starts. So that reliability has been very good on this and that formed our basis for our initial aging management strategy. The licensure application included these and credited the reliability monitoring as I said, but after discussions with the NRC, we elected to establish multiple GALL based aging management programs to manage specific long-lived passive components similar like we would do in the plant.

Now, so what does that program mean? In some areas, the civil structural inspections, we will continue to do that by Amergen as part of the structural monitoring program. Electrical testing will be done by Amergen personnel because it's nonintrusive. You can do it with equipment online or it's visual. The mechanical inspections, in large part, are going to be performed by First Energy and we are currently working with them to build those into their ongoing maintenance practices.

MEMBER SIEBER: If you have a loss of the grid, which has happened --

MR. POLASKI: Yes.

MEMBER SIEBER: And you use one of the combustion turbines as a station blackout combustion turbine, it will be running at around 10 percent load.

MR. POLASKI: Yes.

MEMBER SIEBER: Is this stable at 10 percent?

MR. POLASKI: I'm going to ask Rick Skelskey from the station to answer that question.

MEMBER SIEBER: Usually their more stable with a bigger load.

MR. POLASKI: I understand.

MR. SKELSKEY: Rick Skelskey, Engineering Manager Oyster Creek. So at 10 percent where it's about 20 percent load, it is stable at that and actually does run very well at those loads. And we test that every refueling outage. We bring combustion turbines on to the plant and assume the loads through our transformer.

MEMBER SIEBER: So you've tried.

MR. SKELSKEY: Yes, we do them. We do test that and it is in our surveillance program and that is performed every refueling outage.

MEMBER SIEBER: Okay, thank you.

MR. POLASKI: Any other questions on the combustion turbines?

MR. BARTON: Yeah, one other thing. Do you have the agreement that they can't take it out for maintenance, for instance, you can't take it out for maintenance without getting your approval up front and you can't -- they can't tag it out without going through your control room or something like that?

MR. POLASKI: I'm going to let Rick discuss the details of that.

MR. SKELSKEY: Rick Skelskey again. On the CT maintenance, for planned maintenance, we do get their buy-in ahead of time and for unplanned maintenance, something happens to the CT, the unit does not start, our control room operators do get a call and we enter those into our corrective action process to monitor that. And we also -- we do get reports of their starting so start demands and when they actually start. We get that on a monthly basis from them and then --

MR. BARTON: If you want to bring GE into doing overhaul on one of the units, how do you know that?

MR. SKELSKEY: We work with First Energy. We have regular meetings with them and they schedule that through us when they want to do that maintenance.

MR. BARTON: Okay.

MR. SKELSKEY: So, like I said, for planned maintenance, that is scheduled with us.

MR. BARTON: Thank you.

MR. POLASKI: On Slide 25, discussed briefly our commitment management process for license renewal. There are 65 commitments that are listed in Appendix A of the license renewal application which will go into the FSAR. Fifty-seven of those are for aging management programs and then there's eight stand-alone commitments. We have a -- generated a passport commitment tracking number for license renewal commitments. Our passport system is a data base system that we use at the plant at Oyster Creek and also throughout Exelon for work management, corrective action process, commitment tracking and many other facets of things that go on at the plant and so we've got a license renewal commitment number you know, for license renewal commitments.

Then for that, we have an associated action that contains the details for each of the 65 commitments and each of the implementing procedures that we use to implement these aging management programs as annotated to provide the linkage back to the commitments and to preserve the details of the commitment. This process is controlled by the Exelon commitment management procedures and processes.

If there's no questions on that, I'm going to turn the presentation over to Tom Quintenz. He's going to provide a status on program implementation at the site.

MR. QUNITENZ: Thanks, Fred. We should be on Slide 26. Good afternoon, my name is Tom Quintenz. I'm the Oyster Creek Site License Renewal Engineer. I've been assigned to this project from the beginning to the present time. My responsibilities are to assure the proper level of site involvement throughout the project including input to the LRA and through implementation. I'm here today to tell you about the implementation of our aging management programs.

The programs have generated 368 activities to be performed prior to the period of extended operation; 257 of these are new activities and 111 are enhancements to ongoing existing activities at the site. Each of the activities have been assessed to determine the appropriate time for implementation. Each of the --

MEMBER WALLACE: If you could just explain this, these numbers don't mean much by themselves, but 257 new activities.

MR. QUNITENZ: That's correct.

MEMBER WALLACE: And the obvious question is why weren't they done before? What's different now than before? Why are they done now?

MR. QUNITENZ: These are new activities that were generated as a result of our review of the GALL and producing the aging management programs that we have.

MR. BARTON: These are like one-time inspections people say they have to do before an extended period of -- I think that's the kind of thing Tom's talking about.

MEMBER WALLACE: That's the kind of thing he's talking about.

MR. QUNITENZ: The new activities, as John indicated, were activities that come out of our one-time and periodic inspections.

MEMBER WALLACE: You didn't look at the

buckets before and now you're going to look at the buckets. It's not that kind of thing.

MR. QUNITENZ: No, no, it's not.

MEMBER WALLACE: Okay, it's inspections that you have to do because of the aging.

MR. QUNITENZ: Right, and this was a result of also pulling in non-safety related systems that had the potential for interaction with safety related systems in the plant that were not previously at this level of inspection. The following is a breakdown of when we intend to implement each of these activities. Thirteen percent of the total will be implemented in our upcoming refueling outage in 2006. A significant portion of these activities are associated with inspections that we will be doing with the drywell and --

MEMBER WALLACE: I have no idea how to evaluate this. I mean, if I saw 500 up there, it wouldn't make a difference to me.

MR. BARTON: Yeah, you probably couldn't do them all.

MR. QUNITENZ: I'd have to say that first of all, I'd have to talk about our work management system. We've planned and schedule each year on the order of 15,000 activities relative to operating the station. So these numbers to us are well manageable.

MEMBER WALLACE: It's not a huge new workload for you?

MR. QUNITENZ: I would say that, as I indicated before, there are new activities in here and basically we have the capability to manage those. I know Tim Rausch is here and we've discussed that with him relative to that implementation as well.

MEMBER ABDEL-KHALIK: Was there a prioritization process to decide which of these should be done now and which should be done two years later?

MR. QUNITENZ: Yeah, basically --

MEMBER ABDEL-KHALIK: How was that done?

MR. QUNITENZ: Yes. Basically we took all of the activities that we committed to that were implementing our commitments and we reviewed each of them to determine what the appropriate time was to do. Did we have to have the unit off-line in order to implement the activity or could we do that while we were operating? So we went through each activity to make that determination. We also organized a team of people to take a look at the activities to see which ones would be more appropriately a fit into our refueling outage in this October as opposed to next October or next year and when to schedule.

MEMBER ABDEL-KHALIK: So it's a matter of convenience rather than a matter of significance?

MR. QUNITENZ: I think both weigh into that determination. For example, in terms of significance, we rolled all of the drywell inspection activities into this because we thought that that was a significant item that we needed to really take care of all the commitments relative to the drywell this outage rather than waiting till the next outage. So from a significance perspective, that did weigh into this also.

As indicated on the slide, 19 percent of the total will be implemented during our refueling outage in 2008. The remainder, 68 percent of the total, will be implemented during plant operation while we're online. A significant amount of these activities will be done between the two refueling outages. The completion of this work effort will assure all required inspections have been completed prior to the period of extended operation. In addition, all documents credited for implementing license renewal commitments will be annotated specifically with those commitments. And this assures continued implementation of our aging management programs through the period of extended operation.

Are there any questions or comments? I'll now turn it back over to Mike Gallagher.

MR. GALLAGHER: Okay, so just to summarize, we -- Slide 27, we have established the aging management programs to insure continued safe operation for the period of extended operation. We've also clearly identified and will implement all the license renewal commitments as expected and we are on track for completing the activities needed prior to entering the period of extended operation. That concludes our presentation and we're open to any other questions.

CHAIRMAN MAYNARD: What I'd like to do at this point is first go ahead and take a break. I'd like to get the staff's presentation, public comments. We may or may not call you back up at that time and ask some additional questions at that time. So with that, it's 20 till. Let's take a break and be back here at five till.

(A brief recess was taken at 3:43 p.m.)

CHAIR MAYNARD: We will resume the meeting. I'll turn it over to Mr. Ashley to present the NRR.

MR. ASHLEY: Thank you, Mr. Chairman. My

name is Donnie Ashley. I am the Project Manager, Staff Review of the Oyster Creek License Renewal application. Joining me today is Steve Tenien who is the Scoping and Screening Team Leader, Michael Modes from Region I. He was our Inspection Team Leader on the project. Michael and I will be presenting the results of our staff's review. Roy Matthews is with us. He's the Audit Team Leader and he's present to respond to any question that you may have concerning the audits.

MR. BARTON: You have three hours to figure out what firebar D is taken. Can you tell us that right up front?

(Laughter.)

MR. ASHLEY: I'm still worrying about the phone. Hans Asher is also here and he is to brief the Committee on a confirmatory analysis that we did and that we're in the process of conducting now on the drywell and supporting all of us are the technical reviewers in the audits to answer the questions that you're going to have.

Just a general overview, I won't repeat a lot of the information other than to let you know that there were the five items that the Applicant did mention. There were 108 RAIs in this review and 366 audit questions and in all of those cases we got good responses back from the Applicant and they were all in a timely fashion. We had one major component that the Applicant talked about as far as the fork driven combustion turbine and if I go too fast, stop me and we'll talk.

CHAIR MAYNARD: No. I think the main thing we want to be able to get into is the basis that the staff has used to draw conclusions on the acceptability of the drywell and some of the other technical issues.

MR. ASHLEY: Absolutely we'll do that. This is a listing again of our audits and inspections that we conducted. As far as the scoping and screening in the back of your package are extra slides that you can take a look at if you want to look at the specific mechanical systems, the containment systems and the electrical components and commodity groups. But the scoping and screening results included all the SSCs that were within the scope of license renewal and subject to aging management review. The one additional that we had was I believe on met tower equipment.

Michael Modes, if he's here, if he could discuss the inspection that was conducted.

(Discussion off the microphone.)

MR. MODES: So we did a few week inspection. Next slide. No, that one.

CHAIR MAYNARD: You're going to need to make sure you use a microphone.

MR. MODES: Yes, I'm sorry. We did a two-week onsite inspection March 13th to March 17th and March 27th to March 31st. These were scheduled to nominally support the NRR reviews. The schedule calls for about an eight-month window. We tried to jump in between the audits and the SER.

We had a team and this one was a large inspection because we thought we needed to cover an awful lot of ground and we also needed to have specialists paying attention to special areas. So we had eight inspectors covering all the disciplines and one of those inspectors spent an entire one week period doing nothing but walking down the plants. He has about 30 years experience in the operationalization aspects. He did a 54-A2 nonsafety effect safety inspection.

And one of the inspectors spent the entire two weeks onsite plus the week in between doing nothing but looking at the drywell data, all the videos, interviewing all the individuals, going through all the historical records and going through all the analysis that was performed. The inspection was performed in accordance with Procedure 71002. Next slide.

The scoping and screening portion as I said concentrated on the nonsafety systems whose failure would impact safety systems. The guy who did that emphasized physical walkdowns. He did over a dozen systems. He choose and did over a dozen systems, but that means that he did way more intersecting. I don't think he spent more than an hour each day with us debriefing when he was off running around the plant trying to figure out whether he could find weaknesses in their 54-A2 programs. We concluded that the methodology was adequate and it was consistently applied. Next one.

Aging management program. We did 30 programs and you've heard me say it before from the bottom up starting with the implementing procedures, the work orders, all the information at the plant that gets you to understand what aging they're trying to deal with and whether or not the procedures and programs they're proposing will in fact manage what we see or what we think will occur. This time we did something a little creative and we took one risk significant system, the isolation condenser, rather than grinding through all these programs again. What we did was we took the isolation condenser which is risk significant but does not contribute to ECCS, so it's safety related but not safety and it gets very fuzzy but it's risk significant. It contributes substantially to the plant configuration post-accident and what we did there was we looked at the program that being applied to the aging of that risk significant system and it was quite illustrative of trying to do this thing from the back forward using one system. We concluded that the Applicant implemented the existing aging management programs as they had described them in the application and that acceptable enhancements, etc. were made. Next one.

In response to NRC identified inconsistencies, the Applicant revised the application or entered those inconsistencies. We generated a lot of corrective actions as a consequence.

The Applicant provided assurance that properly updated its current licensing basis in accordance with 54.21b and the Applicant provided assurance that the systems, structures and components will perform the intended function, aging management programs are adequate for the period of extended operation. Overall Oyster Creek's implementation of aging management programs will be sufficient for the extended period.

MR. BARTON: I got a question. You were talking about iso-condenser and some of the exceptions they took or whatever. They took exception to the use of ASME Code Class I small bore piping program and they proposed to inspect one small socket weld off the iso-condenser and the NRC bought that as acceptable. Now I would like to understand why. Maybe you're not the guy to ask but I had that question.

MR. MODES: I'm not the guy.

MEMBER WALLIS: I picked that up as well. I wondered about that.

MR. BARTON: Can anybody answer that?

CHAIR MAYNARD: Donnie, do you have anybody in the staff?

MR. ASHLEY: That did come up during the -- Roy, if you would come up to the microphone. Roy Matthew, the Team Leader.

MEMBER WALLIS: The rationale was it's a sampling process, but it's unusual that the sampling of one is adequate.

MR. DAVIS: I'm Jim Davis on the Audit Team. We've accepted this at other facilities doing one socket weld as representative as under four inch pipe and we've consistently used this because socket welds are small enough that they're not normally inspected.

MR. BARTON: I understand that. That's why I wondered why one was acceptable as a sample. So this is your standard. One is good enough.

MR. DAVIS: Yes, because they're not normally even inspected other than by a system walkdown.

MR. BARTON: Yes, but they do end up cracking.

MR. DAVIS: Well, we're asking for a destructive examination of the socket weld to make sure that there's no degradation that's not visible.

MR. BARTON: But it may or may not be in this one socket weld and you're happy.

MR. DAVIS: With one we're happy because it's not normally included in the program. It's more than is normally required. But we feel that they have to look at least one socket weld to see if they're okay.

MR. CHANG: Ken Chang, the Branch Chief -

MEMBER WALLIS: As long as they claim 95 percent confidence from one socket weld.

MR. CHANG: Ken Chang, the Branch Chief for the Audit branch License Renewal. We're not just arbitrarily accepting the one socket weld. Although it's difficult to inspect we want to inspect one of the possible worst cases. In other words, you pick a biased sample as one of the worst cases. You're not picking along a continuous pipe. You're picking on a fitting, on a reducer, on a socket weld, on something. So that should represent a reasonably bad conditions. If anything should happen, that should happen to that component and also the welders went through the same qualifications. So if you pick one of the worst cases of socket welding inspected, it would give you a reasonable assurance that it's done correctly.

MR. BARTON: I'm just not sure that one welded at every socket weld at Oyster Creek.

MR. CHANG: But if you have 300 socket welds, you cannot inspect all 300 socket welds.

MR. BARTON: I don't think 300, but I was just wondering why one was enough.

MEMBER SIEBER: Well, the issue I think in small bore piping, particularly socket welds, is they do fail and they fail with greater frequency than large bore pipe does.

MEMBER WALLIS: Right.

MEMBER SIEBER: And usually they fail because of vibration. So how do you go and pick the one that represents the worst case?

MR. BARTON: I'm not sure this one vibrates very much.

MR. CHANG: No, this for vibration, this socket weld you select on the basis of similar fatigue. For vibration, there are other criteria to evaluate the stresses and select the potential location of failure. It's like amplitude and frequency.

MEMBER SIEBER: Yes.

MR. CHANG: Now that's different. You do it by walkdown. You observe where you can see the vibration amplitude is bigger than in other places. There are typical examples, typical procedures, by every site to select the location and systems that are susceptible to vibration.

MR. BARTON: I just don't see this one as vibrating. I don't know.

PARTICIPANT: It's not a vibration problem.

MR. BARTON: It sits at a dead lang off an iso-condenser which only gets turned on if we really need it during a event. Right?

MEMBER SIEBER: Right.

MR. BARTON: So that's why I wondered why.

MEMBER SIEBER: You can't also observe.

MR. BARTON: What are you going to observe? You're going to be there when the event happens and see if it shakes.

MEMBER SHACK: That's why he's inspecting it because there is nothing to observe.

MR. BARTON: Ah, yes. Why couldn't I have figured that out?

(Laughter.)

MEMBER SIEBER: You still have to pick the one you're going to inspect.

MEMBER SHACK: He's tried to, I think, pick one with a certain consideration critique potential and --

MEMBER SIEBER: Right. I got it.

CHAIR MAYNARD: Okay. Could we move on.

MR. ASHLEY: Moving right along.

MR. MODES: Any questions?

Okay. You guys are always interested in the current performance of the facility. So the licensee is in regulatory response column two. If you note they have one white in emergency preparedness because they failed to recognize they were in an usual condition during a grassing event. We have subsequently done an inspection and did not fully concur in their root cause analysis because it didn't address fully the human performance element in the white finding. So as a consequence, this remains open.

In addition, they do have one crosscutting issue in the area of human performance which was discussed at the midyear mid-cycle review with them and it should surprise you absolutely not that the crosscutting is failure to adhere to procedures.

MR. BARTON: Why shouldn't that surprise us?

MR. MODES: Well, you did ask a lot of questions about how come they emptied the bottle and as a matter of fact, you reflected exactly the somewhat irritated remarks I had when I was told about it. Any questions?

MR. BARTON: Nothing.

MR. MODES: Thank you, gentlemen.

MR. ASHLEY: Thank you, Michael. Under the aging management programs they happened to talk about the 57 AMPs and again there are listings of the amps that are in your package of slides if you'd like to take a look at those.

This is an example of the aging management on protective coatings and monitoring and maintenance program that was evaluated in Section 3. This one particularly has to do with the inspection of torus bays and in subsection IWE of ASME Section 11.

The structure's monitoring program is 17 commitments identified for that program. It also includes structures for the station blackout system. Ten additional commitments for the station blackout for the Forked River combustion turbines as the Applicant discussed with you.

In the aging management review overview the soliciting of what the team looked at, the numbers of systems, structures and components. The aging management specifically on the drywell talks about --

MEMBER WALLIS: So let me ask you inspection of 100 percent of the sandbed region epoxy coating, is that just looking at it or is that scratching it or pulling it?

MR. ASHLEY: Which slide are you on, sir?

MEMBER WALLIS: Well, I think I'm -- Am I ahead of you or something?

PARTICIPANT: Sixteen.

MEMBER WALLIS: Am I ahead of you?

MR. BARTON: What number are you on,

Graham?

MR. CHANG: Sixteen.

MEMBER WALLIS: Sixteen. Aging management example. Am I ahead of you?

MEMBER SIEBER: Yes.

MEMBER WALLIS: I'm ahead of you. I'm sorry.

(Several speaking at once.)

MEMBER BONACA: You are behind because you're only on three or four.

MEMBER WALLIS: You're ahead of us. It says 100 -- What does that mean?

PARTICIPANT: It's a visual inspection.

MEMBER WALLIS: They do do it to inspect samples.

MR. ASHLEY: Jim Davis on the Audit Team.

MR. DAVIS: It follows the ASTM recommendations for inspecting coatings which is a visual inspection. If you find something, then you have to do something additional.

MEMBER WALLIS: So if it looks funny, it's blistered or something.

MR. DAVIS: Blistered or cracked or peeling.

MEMBER WALLIS: You don't have to scratch it or pull it.

MR. DAVIS: No.

MEMBER WALLIS: Or do anything to it physically.

MR. DAVIS: No, that's not what the ASTM recommends.

MEMBER WALLIS: If it's right, then it's okay.

MR. DAVIS: Yes. That's the normal way. I've talked to the industry expert, the Chairman of D-33, the protective coating committee.

MEMBER WALLIS: If it's falling off it's not okay, but if it's there, it's okay.

MR. DAVIS: If it's cracked or if it's blistered or if it's --

MEMBER WALLIS: Rust streaks or anything.

CHAIR MAYNARD: Isn't there a criteria or a qualification for the individuals doing the visual inspection on this?

MR. DAVIS: Yes, he's qualified.

CHAIR MAYNARD: It's not just anybody that can walk in there and take a look and make a decision.

MR. DAVIS: Yes, you have to be a certified coating inspector and they actually put them upside-down in the sand bed region. It's 18 inches wide. I don't think I'd fit in there, but they actually do a very good visual inspection.

But having had some experience looking at coatings, you can tell when they're going bad and then there are other ASTM tests that can conduct such as a cross hatch test or an adhesion test. So far to date, they haven't had to do any of that.

MEMBER WALLIS: I'm just thinking about my experience with my vehicles or my house or something. Sometimes the paint looks fine, but it's rotting underneath.

MR. DAVIS: That's not normally the case with these epoxy type coatings on metal, on steel. I'm a member -- I was a member of the ASTM D-33 Committee and we had tons of discussions on this and actually Reg Guide 1.54 Rev 1 goes through the ASTM requirements if you're interested.

MEMBER WALLIS: There's a lot of technical evidence behind this.

MR. DAVIS: Yes.

MEMBER WALLIS: Okay. Thank you.

MR. ASHLEY: Slide 19. This is a listing again of the systems that were subject to the aging management review.

MEMBER WALLIS: All these numbers, what do they mean? Does this mean this is typical plant or it's exceptional or what?

MR. ASHLEY: It's fairly typical for this kind of plant.

MEMBER SHACK: I think two of them.

MEMBER WALLIS: Of this type of plant? It's typical of this type of result or license renewal. You get this sort of numbers.

MR. ASHLEY: Yes, the other plants do have similar numbers.

MEMBER WALLIS: It doesn't mean anything to just have a list of numbers there.

MR. ASHLEY: It's just to tell you how much this --

(Several speaking at once.)

MEMBER WALLIS: -- in context or something. It doesn't mean any --

MR. ASHLEY: The aging management program for the drywell shell as was discussed earlier as far as the protective monitoring coating, excuse me, the protective coating monitoring and the Magnets Program.

MEMBER BONACA: Again I have been questioning this issue of preventative actions. Again I mean everything stems from the fact that water is leaking from that refueling cavity and there has to be some design requirements there that are being violated by the leakage and there has been some commitment to use this steel tape, but it doesn't cure the whole problem. I mean it has not cured it in the past. I still wonder. To me it should be a central issue regarding the leakage of the water.

MR. BARTON: I think what we heard was that there were two outages in succession. When they went through that decommissioning plan, they didn't do that strippable coating and we all noticed cracks in the liners.

MEMBER BONACA: Yes.

MR. BARTON: And the water in the bolus was old. Is it that old?

MEMBER BONACA: Yes. If I have confidence that if you really do apply that tape properly.

MR. BARTON: If you apply the strippable coating, if coating has been applied in other outages --

MEMBER BONACA: And is effective.

MR. BARTON: I guess they haven't seen any leakage, have they? I don't know. Ask the licensee. Have you guys seen any leakage if you did put the strippable coating on during a refuel outage?

MR. TAMBURNO: This is Pete Tamburno. In

the past two outages where we've used the strippable coatings, we haven't seen any leakage from above.

MEMBER BONACA: Then it should be part of the commitment. Right? Do you have a commitment as part of all this?

MR. TAMBURNO: Yes.

MR. ASHLEY: This is a listing of the commitments that the Applicant had made in various documents that had been sent to us and if you'll see here, the strippable coating will be applied directly to the line.

MEMBER BONACA: So that's a commitment.

MR. ASHLEY: And it is one of the commitments.

MEMBER ARMIJO: Is it possible that you could put a strippable coating on that was flawed and you wouldn't know it or will you have some other detector for water, either look at the drain lines to see if this coating still is working?

MR. ASHLEY: They, in fact, have a commitment here for monitoring daily those leakages during the outages. Yes sir. It appears that that's where the leakage was occurring during those periods of times.

MEMBER ARMIJO: I thought that might.

CHAIR MAYNARD: One of the -- When they had the leakage before, it wasn't going in the drain like it was supposed to if it got passed that point and from what the licensee said, it sounded like they had changed that where it no longer has the low point where it would drain down by the liner. It would go down that drain so they could tell if they were getting some leakage in that area.

MR. ASHLEY: They would be able to tell, yes sir, at that point.

CHAIR MAYNARD: And my question is of the staff the level of confidence that from what, you said as an individual for at least three weeks going through the data and talking to people about the drywell and different things and other inspection team members here, the confidence level that the strippable tape and that the actions that they're taking will prevent leakage and identify it if for any reason it does occur?

MR. ASHLEY: Yes sir. With the look that was given this entire system and the history of the system, the inspections that were conducted, the audits that were done, although we'll talk in just a minute about TLAAs and all of the open items are linked to the TLAAs and that's in Section 4.7 of the

Safety Evaluation Report.

In addition to that, these other programs on the monitoring, on the coatings programs, were also reviewed by the audit teams in Section 3 as well. So it got a very, very exhaustive look and in a little while I'll bring Hans Asher and we'll talk to you about where we're going from this point to further verify.

It's also my understanding that the coatings inspections that are going to be done this outage in the U2 testing also figure in too. That's the reason we have the open items. It's because we don't have complete information yet. So once we get that information from the outage I think we'll be able to say with confidence that we --

MEMBER WALLIS: Do you monitor the leakage by having buckets at the end of the drains and the leakage only occurs during an outage when you're refueling?

MR. ASHLEY: That's where the original leakage was identified as --

MEMBER WALLIS: So you identify the leakage by looking at the buckets at the end of the drains. That doesn't tell me whether the leakage didn't come down and evaporate on the way down or something. I mean it doesn't have to go all the way down to the bucket, does it?

MR. ASHLEY: If it evaporates, it's gone.

MEMBER WALLIS: Yeah, but it still shows there's been a leak.

MR. ASHLEY: It would be a very minor leak at that point.

MEMBER WALLIS: I don't know because a damp surface can corrode quite nicely.

MR. ASHLEY: But with the temperatures that occur during normal operation --

MEMBER WALLIS: It would evaporate.

MR. ASHLEY: -- the water doesn't have time to --

MEMBER WALLIS: -- or just --

MR. BARTON: That's secondary normal operation you're leaking when you shut down/cool down.

MEMBER WALLIS: That's when they leak. Right.

MEMBER SIEBER: Yes.

MR. ASHLEY: We don't feel like there's a leakage that we've seen -

MEMBER WALLIS: Don't feel like. That's not good enough.

MR. ASHLEY: -- was not operation leak.

MEMBER WALLIS: So you're assured from some analysis that if there were a leak it would show up in the bucket and not be evaporated somewhere or just leave something else damp which might then do something later on.

MR. ASHLEY: I don't know how to answer your question.

MEMBER WALLIS: Or leave a puddle at the bottom of the --

MS. LUND: Hans Asher is going to address that.

(Off the record comments.)

MR. BARTON: I don't know if it would leave a puddle, Graham, because what they did when they went in there and they sloped the floor and put epoxy on it so it seals.

MEMBER WALLIS: It could be a damper.

MR. BARTON: There could be a damp spot, yes.

(Off the record comments.)

MEMBER WALLIS: Certainly if there was sand there, the sand could gather the water and --

MEMBER SIEBER: Yes, there's more sand. You're right.

MEMBER WALLIS: That's good then because

previous the sand could stay damp and that's what happened. That's how you got the corrosion without necessarily draining at all.

MEMBER SIEBER: That's right.

MR. ASHER: I will address your question about the operation of water. We've heard about this a long time back even during the Dresden containments and we asked the same questions that you are asking to the applicants. Okay. And the general answer was that it will operate and it won't corrode anything. I said no. I'm not ready to believe that. So what we resulted that did, the earlier one, and I saw a separate case too that we asked them to do the UT measurements from upper areas through which the water is continuing to the sand bed area. Okay. And a number of applicants said unless they see no activity of water at all during the entire life, then we will say that is not necessary. But that we have seen any water leakage from their refueling cavity or any other areas collected in the sand bed area, then the whole spherical area and cylindrical area are suspect. In this case also, at Oyster Creek also, they are required to do the UT in the upper area of the shaft.

MEMBER WALLIS: So the UT is the real check rather than looking in the buckets.

MR. ASHER: Correct. UT is the real check.

MR. ASHLEY: Thank you, Hans. This is a slide that discusses the aging management, the in-scope inaccessible concrete and that would be in the structures system. The time limited aging analysis sections 4. These are the TLAAs that were reviewed and accepted by the teams.

And if I could, I would like to go ahead onto the 4.72 and talk about drywell corrosion. I know that's of interest to the subcommittee unless you have specific questions about an item here that you would like to talk about before I jump to the drywell.

CHAIR MAYNARD: Go ahead.

MR. ASHLEY: Give me just a second to get there.

(Off the record comments.)

MR. ASHLEY: We also have with us --

MR. ASHER: Jason Petty.

MR. ASHLEY: -- Jason Petty from Sandia National Labs. So I'll turn it over to Hans to discuss this.

MR. ASHER: In case you ask me very difficult questions, he's here to help me.

MEMBER WALLIS: Okay.

MR. ASHER: Well from this slide, the only thing I want to point out are two things, the load that we have considered which are -- Okay. Let me first start with --

CHAIR MAYNARD: Can we wait just a minute here? Do we have this slide?

MR. ASHLEY: Yes sir. They should be in the back of your handout. There should be several slides there, the last four I think, the last four or five.

(Off the record comments.)

CHAIR MAYNARD: Thank you. I have it.

MR. ASHER: Do you have it everybody? The first thing I want to explain, the reason why we embarked on this particular plant for analysis purposes, we have not done this kind of analysis on other plants, containments, because in all of them they have certain corrosion but the corrosion was within certain limits and it never compromised the minimum required thickness from the design point of view. In this particular case, the degradation is quite severe in many ways of the same bucket area and we wanted to comfort ourselves that is this degraded containment be able to perform its function in the next 20 years. This was our aim.

So though we are depending quite a bit on the commitments that the Applicant has made, but this is something that we want to make sure ourselves that this particular degraded containment is able to withstand the loads it is designed for.

MEMBER WALLIS: Did they do a similar analysis or did you do it?

MR. ASHER: Yes, in 1992-1993 time frame, General Electric had done an analysis and that is what you were talking about before, 0.732 ages and all that.

MEMBER WALLIS: Okay.

MR. ASHER: That came from an General Electric analysis. Okay. On this slide, I want to point out only two items. General loads, loads that we have considered are the normal operating loads as well as the seismic load. Seismic load we have considered the static coefficient from SFAR which I think are bounding because subsequent to the basic load that are used in the SFAR, Oyster Creek have done other detailed analysis. But this load we consider our bounding one.

MEMBER WALLIS: This is a dead load. There are also pressure loads from --

MR. ASHER: Yes. The next items,

controlling load pieces. There are controlling LOCAs that we have considered and truly the LOCAs that we have considered are close to 10 to 12. Out of that, we selected three of them which are going to control certain aspects of the design.

The first one is a refueling. Refueling is basically during the shutdown. It is water in the refueling cavity that puts weight on the drywell shell and the buckling is a possibility under that load and particularly for the containment we ought to look for those things.

The second is a design basis accident with earthquake which is a part of LOCA, normal LOCA calculations. Post accident flooding with earthquake that is also part of our LOCA calculations in SRP and everywhere else. So these are the three.

Now other two items, model geometry and modeling corrosion. I want to explain to you by sketch rather than by speaking it out. Can you go to the first sketch?

(Off the record comments.)

MR. ASHER: Okay. Sandia National Lab has done the full analysis. In the case of General Electric, what General Electric had done was take a 36 degree splice which is one-tenth of the total. We did here because we know have computer capabilities to completely do the final analysis of the entire shaft. So we used that particular technique and Sandia was also in earlier in the degraded containment research and they produced a couple of reports on this particular aspect. So we hope that Sandia will be able to do justice to this type of problem that we are encountering in Oyster Creek. And in my opinion when I read the draft report that they gave to me, it's like poetry to a structural engineer.

(Laughter.)

Here they modeled the personal lock equipment edge which I don't think were separately modeled in the case of General Electric. Then there are ten vents around here which are connected to the torus and generally in the vent header area, but in the second one -- Here. I just wanted to show the spring that we have attached to here just to be more realistic about the flexibility of the vent to move around. These two springs were attached, the Sandia computer separately from this particular model analysis and inserted those springs into the model. Apart from that, Sandia has considered the stiffeners and all the beams and all the details that are necessary, Sandia National Lab has considered in this particular model.

Second, I want to show you the degradation that we used in our analysis. From cylindrical we have used T equal to 85 is after the 0.406 is the as-built thickness. Then 0.0075 is the one that Applicant has computed from the 1980s to 2004 the kind of readings that they have from the upper area.

MEMBER WALLIS: I'm sorry. I'm trying to --

MR. ASHER: These are corrosion rate.

MEMBER WALLIS: These thicknesses are --

MR. ASHER: 0.406.

MEMBER WALLIS: -- measured values or --

MR. ASHER: 0.604 is an as-built.

MEMBER WALLIS: No. It's ASME as-built before corroded, before corrosion.

MEMBER ARMIJO: No, the nominal thickness -- Well, we have a conflict with the Amergan submittal and your name there. Their table shows a nominal design thickness as 0.640 and the minimum measured thickness as 0.604.

MR. ASHER: Okay. 0.604 minus we took the 25 years off extended period of operation.

CHAIR MAYNARD: The actual 0.604 is the minimum measured.

MR. ASHER: Yes, because we are to extrapolate to 20 more years. So it's a hypothetical in that sense. But that is what's likely to occur. That's what we are considering. So we used 0.585 over there. Then in the upper sphere there was no indication of any particular corrosion. The knuckle area did not seem to be -- And even if there is slight closing, the knuckle area, it would not affect the analysis too much and middle sphere, again we had corrosion rate available that we used, 0.678 minus circular point. That's what we used as a thickness.

Now in the sand bed area, I think I would like to go to the next slide. No, let me go back to explain something more. I want you to realize here this is bay that we have considered, bay. It's the red line here. There are one bay, two bays, three bays are shown here. Each bay has an area of approximately 50 square feet and the corroded area that we say we computed the amount of --

MEMBER WALLIS: Can I go back? The reason the steel is so much thicker down there is because of these pipes coming in.

MR. ASHER: Well, a number of things. First thing, it is the bottom of the shell. So it needs the more bearing.

MEMBER SIEBER: That's where all the weight is.

MR. ASHER: So right from this area, it's 1.54 inches. Up above there, thinner.

MEMBER WALLIS: It's big jump from 0.65.

MR. ASHER: Yes, it is. And that is where some of the disconnected stresses do build up too. We'll talk about that a little later, but right now what I want to consider is only the model of the -- Okay. This one. Here if you see, these are the thicknesses we -- Let me give you where we got these readings from. We got these readings from the 1992, I think, before Oyster Creek applied epoxy coating. They took the readings in each and every bay to see how much is corroded and where to grind it out and, you know, you asked a number of questions on those things. So you know that. So that time they had taken the readings in a very detailed manner.

We had those tabulated everywhere and so what we used was an average thickness of those readings that came out of the 1992, I believe. Was it 1992?

PARTICIPANT: Yes, it was 1992 when it was --

MR. ASHER: Taken from outside.

MR. ASHLEY: I'm sorry. Ahmed, I'd like you to use the mike.

MR. WO: Ahmed Wo with Exelon. In response to your question, Hans, it's 1992 that we took UT measurements from the outside.

MR. ASHER: Okay, and this is what we --

MEMBER WALLIS: So it seems bigger than the 0.8 to the 0.764 or whatever it was we talked about earlier.

MR. ASHER: I will come to that. Just a moment. I'm coming to that.

MEMBER WALLIS: Okay.

MR. ASHER: I want to emphasize one thing that we tried to compute the corroded area versus the bay area. The bay area is typically 50 square feet in area, okay, one bay that I'm showing you here, this bay, based on one bay, nine bay, that approximately 50 square feet in area. The most corroded areas are bays 13 and 1. Isn't it, Jason?

PARTICIPANT: Yes, at their center spot.

MR. ASHER: Bay one and bay 13 is the worst case area. In that area, the square feet area covered by the serious corrosion is close to about four square feet or so. Okay. So what comes out is the area corroded in the whole bay is 10 percent of the total area.

MEMBER WALLIS: Why did it corrode in those places?

MR. ASHER: Yeah.

MEMBER WALLIS: You have this leaking water running down the side of this thing and certain places it's very preferentially corroded.

MR. ASHER: Yes, the logical explanation that I can figure out was that this is quite a steep area. Let's go back to the earlier slide. Yes, that's good enough. From here, this area is very easy for water to pass through. When there is sand there, it passes through the sand and accumulates at the bottom area, but the bed of the sand bed area and that is where it stays stagnant for a long period of time. That is where most of the corrosion is located. In each and every bay, that's the way what we noted.

MEMBER WALLIS: Why is bay one so much worst than the other one?

MR. ASHER: Because my --

MR. BARTON: Because that's where the cracks are in the liner.

MEMBER SIEBER: That's where the leak was.

MR. ASHER: Where the leak concentrated. The leak was not uniform all around this area.

MEMBER WALLIS: It was up above somewhere and it ran down into the --

MR. BARTON: The liner. It comes from the top up in the cavity where the liner is.

MR. ASHER: From the fueling cavity. Starts from the top.

MR. BARTON: And the liner has cracks and the cracks are not in all one spot. They're around the liner. So I guess where the biggest cracks in the liner are is where the most water comes in.

MEMBER WALLIS: But cracks, this was general corrosion right over the whole surface. It's not --

PARTICIPANT: No.

MEMBER WALLIS: From the top.

(Several speaking at once.)

MR. ASHER: There are no cracks. There are no cracks anywhere. They found general corrosion. I want to correct this.

(Several speaking at once.)

MEMBER WALLIS: Cracks in the liner.

MR. BARTON: Cracks in the liner. The liner in the cavity.

CHAIR MAYNARD: Talk -- Let's be careful.

MR. ASHER: Oh, there are stainless steel liner cracks. I agree.

MEMBER SIEBER: There you go.

MR. ASHER: But the cracks in the drywell are a different problem all together.

MEMBER WALLIS: That's why the bucket was filling. The bucket was filling from bay one and not from the other ones. You have five drains or something here, don't you?

MR. ASHER: Yeah, there are ten drains and the buckets were filling down even after the --

MEMBER WALLIS: And there's a place where the water was found.

MR. ASHER: After they put the epoxy coating in.

MEMBER WALLIS: And the place where the water was found is consistent with the place where the corrosion was found.

MR. ASHER: Normally so but I have to ask Applicant where it is, that particular question. The question is whether the latter on whatever water collection was found was in those particular bays or they were normally in any bays. Any idea?

MR. TAMBURNO: This is Pete Tamburno. In general we saw more water in bays one, 19 and 13.

MR. ASHER: One, 19 and 13.

MEMBER WALLIS: There was water elsewhere too.

MR. TAMBURNO: Yes sir.

MR. ASHER: That could be. I mean that's anybody's guess.

MEMBER SHACK: He has corrosion everywhere.

MR. BARTON: Yes, you had corrosion.

MR. ASHER: Corrosion is in all bays to some extent, but these two bays were serious corrosion and that's why we took that slice we are showing. This is the area where we took the lowest reading to see the structure discontinuity effect of the thicker part here with this thinner here.

MEMBER WALLIS: You took a certain amount of square feet and said that's thinner than everything else.

MR. ASHER: Yes. Exactly. And this is the thinnest area, 0.705 which is the thickest and up above we took 0.618 is the thinnest to see how it behaves in analysis.

MEMBER ARMIJO: Now those are different than the numbers presented in other submittals.

MR. ASHER: Yes.

MEMBER ARMIJO: They are actually less

than what seems to be later data. Am I confused?

MR. ASHER: No, this is really the earlier data but why this? Because 0.998.

PARTICIPANT: Some of these averages question how you've done the average here.

MEMBER ARMIJO: Just go ahead, but I don't want to quibble. But there's an inconsistency between this table and that chart and somewhere along the line --

MR. BARTON: Were they done the same time? This is '92. What's that date?

MEMBER ARMIJO: It doesn't say, but just somewhere along the line, sort that out. Your approach is what I'm interested in.

CHAIR MAYNARD: But are these numbers though from a measured value and that you took off an estimated corrosion rate to get to these numbers or are these the actual measures?

MR. ASHER: For the upper part of the drywell, yes that's what we did. For the lower part of the drywell, we used a measure. We did not extrapolate them because the Applicant is insisting that there's not going to be any more corrosion in this area from now on. So we have not calculated any corrosion rate at this time, but we have used what they have given to us.

MEMBER WALLIS: The problem we have is that the table in the supplemental gives numbers different from the numbers you used.

MR. ASHER: Yes.

MEMBER WALLIS: We don't quite know what's going on.

MR. GILLESPIE: Hans, let me. You described it earlier and you just may need to step back and describe it again. These numbers are not the Applicant's numbers. These are numbers that the analysis, the analysts at Sandia, came up with given that the major corrosion area in each of the 50 square feet was actually only about four square feet and you said that.

MR. ASHER: I said that.

MR. GILLESPIE: And so these are numbers that came from the NRC supported analysis, not from the licensee.

MR. ASHLEY: Did the Sandia folks start with a measured UT data and then treat them in some way that converted them into these numbers?

MR. GILLESPIE: Yes and that's the key and Hans and Jason can probably go through that if you want to hear that detail.

MEMBER WALLIS: They start with the UT data.

MR. GILLESPIE: Yes, they started with the UT data.

MEMBER WALLIS: Okay.

MR. GILLESPIE: But then they had to do something with this four square feet over --

MEMBER WALLIS: They made it thinner in places.

MR. GILLESPIE: Yes, because they had to average it over the 50 square foot pie-shaped segment in order to get the analysis done.

MEMBER WALLIS: Got it.

MR. GILLESPIE: So it's an averaging process they use in the analysis.

MEMBER WALLIS: But it would help. Sam asked earlier for sort of a matrix of where the measurements were so you could see what was actually done and you could get some idea how it was averaged and all that.

MR. GILLESPIE: Yes.

MEMBER WALLIS: That would be very helpful if we're going to really dig into this.

MR. GILLESPIE: And this I think you'd find -- We haven't distributed it because Hans has a draft NUREG CR but I think we can share that later with the Committee.

MR. ASHER: I will say when I come to the results I want to emphasize the preliminary results. We are still doing some studies and it might change from what I said.

MEMBER WALLIS: So this is a draft NUREG CR. Is the NUREG CR going to be available before we look at the final SER on this thing?

MR. ASHER: We plan to -- I can provide you with a copy of a draft report if you want to look at it.

MEMBER WALLIS: But the final is going to be available?

CHAIR MAYNARD: Aren't you waiting from some of the inspection results from this outage to see if there are any adjustments that are needed in this?

MR. ASHER: We are planning that. But in case studies, if there are very large differences in the thickness measurements that we see in the October outage, then we will have to make adjustments and recalculate the same stresses review. We are planning that yes.

MR. GILLESPIE: But if the licensee -- As Hans said, the ingoing assumption on the part of

Oyster Creek was that the coating has arrested because it eliminates the oxygen. So the expectation is that the current measurements should be within some uncertainty.

MEMBER WALLIS: Nothing has happened for ten years.

MR. GILLESPIE: That nothing has happened for ten years. Hans is only suggesting that if there's a significant difference that we'd have to eyeball it again.

MEMBER SHACK: Since you're doing a finite element analysis, why do you have to do the averaging?

MR. ASHER: Well, because the rest, except the thin area I'm showing you, in each bay the areas are much thinner, much smaller, than this area that I'm showing you here and the rest of the bay is originally 1.152 inch more or less thickness. There might be some isolated pits in one place or the other, but as far as the very serious corrosion like this --

MEMBER WALLIS: Only in a few places.

MR. ASHER: -- it's in those places. No, in each and every base at the bottom, there is some corrosion. But these are the controlling corrosions.

(Several speaking at once.)

MEMBER SHACK: But you're saying you're

averaging over the bay and I'm saying you have this thing into umpty-dump finite elements. Why not each finite element?

MR. ASHER: Jason, do you want to address this question?

PARTICIPANT: For the analysis that we're doing it's really not practical to build in that topology of the point to point throughout space. There needs to be some sort of an averaging process for it to be practical. I don't have corrosion data that specific to do that for one. Two, the elements we're using --

MEMBER SHACK: But I mean you can make it as refined, obviously you can't as refined as your corrosion data.

PARTICIPANT: Obviously with enough time and enough data if it was specific enough, we could do that. Yes. But it's really not practical.

CHAIR MAYNARD: From what you have seen, do you think that would make any difference in your results?

PARTICIPANT: What we do is we're trying to have the numbers shaded on the conservative side obviously so that we're covering any of those arms.

MEMBER SHACK: That's what I was losing

whether you were averaging the thin area over the whole bay which didn't seem conservative or you made the whole bay correspond to the thin area.

PARTICIPANT: Now my understanding is that the source that we've taken these values from were thinner points that were shown by visual inspection. They were visually inspected and then measured at the thin locations.

MEMBER SHACK: And then you assign that now to the whole bay.

PARTICIPANT: There were points throughout a certain region and then that was averaged and assigned uniformly to the whole bay. So, yes, within that bay there are thinner regions and thicker regions. That's why those two smaller regions that Hans had mentioned were added in for us to capture some of the effects of what if there's a smaller region that's much, much thinner that's not captured in this averaging process that we've done.

MEMBER WALLIS: I think it would be much clearer if all this were spelled out, you sort of showed there 150 measurements, this is how they scatter statistically and what did you do in terms of averaging, did you average the low ones, did you average the whole thing, were there lots of them showing no corrosion at all and a few showing -- We could see it. That would give a picture.

MR. ASHER: The report will explain those things for sure.

MEMBER WALLIS: There is some work.

MR. ASHER: Yes.

MEMBER SHACK: Let me just see if I have it in my mind though.

MR. ASHER: We will make sure that we explain this a little more.

PARTICIPANT: Yes, we'll have to.MEMBER SHACK: You have an average for the bay now and then you put in a local average for these low spots.

MR. ASHER: Low areas, yes.

MEMBER SHACK: Okay. Got it. So you're probably conservative.

MR. ASHER: Because this is what we are afraid of, the structure discontinuity and of course because of the thickness differences. We wanted to see what kind of effect it has.

MEMBER WALLIS: First it was the stuff that shows the variation of the thicknesses and what are the actual reportings in thickness?

(Off the record comments.)

MEMBER SIEBER: I guess I have a couple of questions. When you consider the corrosion of the drywell shells that changes the mass of the system and your infinite element analysis takes into account the fact that that mass is changed. From a seismic standpoint, it changes the vibration mode, frequencies and response, amplitudes.

(Two conversations going on at once.)

MEMBER SIEBER: And you also took that into account. How did you take into account the fact that the sand pocket was removed because that also was a cushioning effect and the support for the drywell.

PARTICIPANT: It has no support.

MEMBER SIEBER: But it said in your assumptions that you just used the coefficients from the FSAR which reflect the fact that the sand pocket was there. Right? Go ahead. I just need for you to clarify what's going on here.

MR. ASHER: Yes. Let me explain two things separately. Okay? For seismic loads, what we have done is we have taken the upper bound values that were being computed by the Applicant. That was done during the construction. Since that time, the Applicant had done a number of other analyses to reduce the loads on certain supports and certain piping supports and everything, the sophistical analysis in 1993 for example. And I had reviewed that in 1993. So I know that they had done that.

Now I asked them a question as to these values are bounding values or they are the one some other analysis were bounded and I was told that no they are the maximum that you can get out of -- these valuesare the ones that are good values.

Now how we have applied the seismic load here, that is important here from what you are telling me. The way we have applied seismic load here is at the bottom there is a static load. There is no dynamic analysis here. It's a moment. It does not have the dynamic seismic analysis where we would put damping and we take the -- We have not done that because we felt that we wanted to concentrate much more on the drywell corrosion. But at the same time, I agree that we ought to have a representative seismic load and --

MEMBER SIEBER: The degradation and the modifications that they made change the seismic response and I'm wondering did you take it into account, yes or no, and if you didn't, how do you know you're still conservative as far as overall strength of the drywell is concerned in these three cases?

MR. ASHER: Jason, do you want to say

anything? Okay. This is what we have used, but we can --

MEMBER WALLIS: I'm looking at the original report and you have the measurements in higgly-piggly in fashion. There isn't a pattern that makes any sense and the numbers vary a lot. Rather than use this average, you have to do some sensitivity study where you say suppose we put in something like my colleague Bill Shack suggests, some sort of a distribution of thickness or something and does it make a difference.

CHAIR MAYNARD: Wait. We can't be trying to answer three or four questions at once. We have one question right now.

MR. ASHER: And Mike Hessler from Sandia wants to.

MR. HESSLER: This is Mike Hessler from Sandia. I supervise the work, the analysis, that Jason did. The question as I understand it was that, and we agree with you, that the changes in the geometry due to the degradation, due to the removal from the sand from the sand pocket, would affect the seismic loads.

For the analysis, the approach that we took here, we knew we didn't have enough information to do the rigorous level of analysis that GE had done. We don't know what the piping is. We don't know all the equipment weights. So we had to utilize information that was published in the FSAR. I think the emphasis that we tried to do is to look at what, not so much the absolute values, but the changes due to the degradation. We were concerned early on that even if we did a detailed analysis of the undergraded shell we would not get exactly the same numbers that GE did just because of the difference in the modeling and the uncertainty in the loads.

So I think one critical aspect of the analysis that we did was to do an analysis initially with this three dimensional model with all the same assumptions of the undergraded drywell shell and then apply the degradation to that and see how that changed the factors of safety for both stresses and buckling for the three load cases that we had. So I wanted to emphasize that I think that's a critical element of this because we had to rely on incomplete information on all of the loads. We didn't go back and do a time history analysis to get the seismic response of the shell. Obviously, we could given the time and resources, but the emphasis as we understood it here was to really understand what the effects of the degradation are.

MEMBER SIEBER: Okay. What you did is what I thought you did and probably what I would have done. My follow-on question would be how do you know that's conservative with regard to whether the containment will fail or not under these cases up there.

MR. HESSLER: How do I know it's conservative. I have to rely on the fact that the original design was reviewed and approved and reflected all of the loads. We used the same loading information that GE used in their analysis. We just applied it to this three dimensional model. Again, I --

MEMBER SIEBER: I'm really going to have to think about that.

MR. HESSLER: But I just wanted to make sure you understood.

MEMBER SIEBER: I'm a slower thinker than some people.

MR. HESSLER: I just wanted to make sure you understood what we did and also --

MEMBER SIEBER: Be patient. I think I do.

MR. HESSLER: -- the focus that we really thought we needed to look at was is the effect of the degradation significant rather than looking at the absolute numbers in all cases.

MEMBER WALLIS: And you found that they were.

MEMBER SIEBER: I'm interested in whether it fails or not. To me, that's specific.

MR. HESSLER: I understand. I'm just clarifying the scope of the work.

MR. GILLESPIE: I think -- Sandia only really did the tasks that we asked them to do and remember this is a confirmatory measurement. We're not designing a plant and we're confirming the projection made by the licensee and a 1991-1992 GE calculation. And the question on the table for us was because that calculation showed a very small margin existed given it's a small margin let's have an independent group take the best data we have available which was limited data and do an independent calculation to confirm the size of that margin. So I think they've done what we asked them to do. But this was not a de facto re-initial licensing review or design review. So there were limitations of what we asked them to do and I think they did exactly what we asked them to do and that's why it's by difference.

MR. ABDEL-KALIK: The analysis assumes

that the locally-thinned areas are the same location as the vent lines. In fact, they are right above the midplane of the vent lines in bays one and 13. Is this really the most limiting location for these locally-thinned areas?

PARTICIPANT: That picture is a little misleading. It's actually just below the vent lines.

MR. ABDEL-KALIK: Yes, but they have the same azimuthal location angle wise. Is that the most limiting azimuthal location for those locally-thinned areas?

MR. ASHER: That is true. The early question was asked as to why all the corrosion took place at the bottom of the, at the sand bed area and that is where the serious corrosion is concentrated.

MR. ABDEL-KHALIK: So you're saying that the location was not selected based on where it would be most limiting, but based on actual observation.

MR. ASHER: Actual observation.

MR. BARTON: Where it was, yes.

MR. ABDEL-KHALIK: Okay. Thank you.

MEMBER WALLIS: But you've said that this is sensitive to modeling and this business of averaging and putting things in certain places gives you a result. If you put the thin areas somewhere else and you'd average in a different way, you'd get a different answer and Frank Gillespie just said that you're worried about having very low margin. So it seems to me that you have to pretty thorough about doing your sensitivity analysis. Saying suppose we did it a different way. What difference would it make?

MR. ABDEL-KHALIK: Intuitively this is not the most limiting location for the locally-thinned area.

MR. ASHER: Well for locally-thinned area what we did was we looked at the results of that 1992 observations that UT results were done because that time they truly went inside everywhere and took the UT results right from where the corrosion is occurring at that time and measured the metal thicknesses. To us it was very reliable measurements and based on that, we made certain assumptions and that's why we are saying the assumptions we made.

You are quite right. To somebody else, some other analysts can make some different assumptions. They come out with it different. But the way we have done it, we are going to the conservation site and wherever we had the readings, where we had a particular doubt or something, we erred on the conservative side. So that's the way we have done the analysis considering the measurements that were taken during that time.

CHAIR MAYNARD: I think it would be a different situation if you still had active corrosion going on.

MR. ASHER: Right.

CHAIR MAYNARD: And I think it would be more important to go for the potentially worst case. Where you have a defined scope, you know what the situation is and you have a mechanism in place that's supposed to stop additional corrosion, that's a little different situation.

MR. ASHER: Yes.

MR. ABDEL-KHALIK: I mean that would be true if we really knew the topology of the surface and knew exactly where the thinned areas are to a high level of confidence. I'm not sure that we do.

MEMBER WALLIS: I thought the question was even with no corrosion is it safe now, even with no more corrosion. Isn't that the question we're asking you?

MR. ASHER: Yes. Let's see the slide on approximate safety factors. Again, I want to emphasize these are the initial preliminary results.

So don't count on the numbers. But the degradation, these are the values. You can see the difference on the refueling load combination for example. The safety factor again is buckling. If it is not degraded with same taken out, the SF itself would be 3.85. Now with degradation, it comes out to be 2.15. So you can see right away the impact of degradation here.

MEMBER WALLIS: But that means that it's twice as strong as it needs to be to avoid collapse. Is that what a safety factor of two means?

MR. ASHER: Yes.

MEMBER SIEBER: That's the typical code requirement.

MR. ASHER: There's a code requirement. Two is the minimum code requirement. They are at margin 2.15. Now sometimes you can have 1.5 safety factor. It doesn't mean it's going to buckle right away.

MEMBER WALLIS: Right.

MR. ASHER: But still it doesn't meet the code requirement.

MEMBER WALLIS: The more confident you are the less safety factor you need.

MR. ASHER: Absolutely yes.

MEMBER SIEBER: That's why it's two.

MR. ASHER: The accident condition, there is no question of buckling there. It's mainly the tension stresses and memory stresses and post accident load case, all stresses are within level D requirements and buckling you can see the safety factor again 3.65, 2.74 with degradation. So you can see the effect of degradation here.

MEMBER WALLIS: I think you have a kind of engineering judgment and even if you fiddle around with the way you put these various thin regions you get a safety factor of around two.

MR. ASHER: Right. Two. Exactly. That's what we are looking at.

MEMBER SHACK: Now did you take this all the way to failure to see just what the ultimate load was?

MR. ASHER: No, I think because we were working with the load combinations that are designed load combinations.

MEMBER SHACK: So you're only looking at design loads.

MR. ASHER: Yes, we did not go all the way.

MEMBER SHACK: Not 67.06.

MR. ASHER: Internal pressure you are thinking about. Right?

MEMBER SHACK: Yes.

MR. ASHER: No, we didn't do that.

MEMBER SHACK: Right.

MR. ASHER: We held on that for Peach Bottom. Sandia National Lab has done that for Peach Bottom all the way up to internal pressure going on to collapse, not collapse, but up to certain staid limit.

PARTICIPANT: Predictively.

MR. ASHER: Predictively.

MEMBER SHACK: I mean you did for 67.06 you did ultimate loads.

MR. ASHER: Yes. And we've done that for other plants, but not for Oyster Creek.

MEMBER WALLIS: It says in your figure refueling buckling location. That seems to indicate to me that you have buckling.

MR. ASHER: Well, again, I have to explain this to you. Because of the stresses that are developed, higher stresses in that area, so the likelihood that the buckling will occur if surely the loads are much more than this, they will buckle in those areas. That's what we are showing. It's not that it's a buckled area.

MEMBER WALLIS: If it fails by buckling by the steel detaching itself from the concrete into the well, is that what happens because you would think the concrete would give it some stiffness if it tries to buckle outwards?

MEMBER SIEBER: It's a weight load from the refueling.

MEMBER WALLIS: Doesn't that buckle it outwards?

MEMBER SIEBER: It can go either way. If it's constrained by the concrete then it's going to go in.

MR. ASHER: Yes, it can go in.

MEMBER SIEBER: It is stronger in that configuration where it's forced to go in. But it can still go in. There is a lot of weight there.

MR. BARTON: Damn right.

MR. ABDEL-KHALIK: So if the locally thinned area is azimuthally shifted to that location, would it be possible for the safety factor to be less than the code requires it?

MR. ASHER: When we tried to locate this locally thin area where several corrosion has been recorded, why should I put it in a different place? I have no reason to do that.

MEMBER ARMIJO: Well, you might if you hadn't sampled every area. So if your sampling skipped large areas and you have no data.

MR. ASHER: No, but in other bays, we had the other bays too. We took one and 13 bays because they had the worst corrosion. We could have taken the thin area in each and every bay and it would be much smaller than this. Okay. This was about four square feet or so. We could have taken two square feet, a small area, with thinning not as much as this, the other way, but that would not have made any difference in understanding the mechanism of buckling.

MEMBER WALLIS: Where's the thin area?

MR. GILLESPIE: Yes, I think again this is a confirmatory licensing calculation. This is not for us a research project where we're actually going to look at -- We are trying to confirm the licensee's assertion on their margin. We are actually not trying to independently establish the margin ourselves. So this whole analysis was done you might say on the as-found condition in 1992 of that shell as best we can judge from all the inspection information, etc. But I think structurally a small hole is not our interest here. It was broad degradation that would affect this kind of safety margin. So a small thin spot wasn't going to matter.

Again we're confirming their number. We're not trying to independently calculate something that's totally ours.

CHAIR MAYNARD: Can we go on?

MR. ASHER: Thank you very much. I want to talk a little about commitment in the open items. I want to just point out a few things in the open items.

(Off the record comments.)

CHAIR MAYNARD: Okay. Could we pay attention here? Okay. Go ahead.

MR. ASHER: Yes. These are the five open items we have right now and during the Applicant's presentation, it said that the first open item is the one that they are working on and they are going to put in stove one, they are going to put four probes which results in the area of the drywell shell and they say that other four are accepted by NRCI. I disagree with that. The OI on the embedded shell is not something that we have completely zeroed in on because quantitatively the Applicant provided a pretty convincing response qualitatively that it is a concrete environment and it is a new chance of having oxygen getting into that area and at the most what it can do is not less than 0.732 or whatever they had shown in there. That was their argument and qualitatively I tend to agree with that argument.

But I do feel that they should show some maybe chipping concrete in a particular area where the damage had been the most, for example, in the sand bed area to show that there's no corrosion here or there's a minimum corrosion. Something has to be done in that area.

We also provided an NXER report that the Office of Research had developed earlier where they can really find the thickness of the matter between the embedded shell. These are guided but they are more experimental in nature. I did request the Applicant to explore some of them to see if they can find something, to see if the metal thickness can be measured somehow.

So embedded shell is still the annoying one. It's very difficult to -- Qualitatively as I say I agree with their arguments, but quantitatively I don't have anything to go by.

The other three I agree with the Applicant's conclusion that we have taken care of through commitments and everything else.

MEMBER ARMIJO: I think -- I keep going

back to this one table in that June 20th letter. I think it was a response to a request for additional information. The Applicant submitted data showing the margin for the lower sphere which I presume is the embedded part of the containment. Is that correct?

MR. ASHER: No, the lower sphere includes the sand bed area.

MEMBER ARMIJO: They have a separate line for sand bed than they have for the lower sphere. But you're saying the lower sphere is let's say below the equator. Is that --

MEMBER SIEBER: Below the knuckle.

MEMBER ARMIJO: Below the knuckle. All right. I understand now.

MR. ASHLEY: Thank you Hans. Which brings up to our conclusion. The staff has concluded that the depending resolution of the open items 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; that any changes made to the Oyster Creek current licensing basis in order to comply with 10 CFR 5429(a) or in accordance with the Act and the Commission's regulations.

CHAIR MAYNARD: Appreciate it. I would

just like to make sure everybody realizes that that's the conclusion that you're presenting. That's not the ACRS conclusion at this point. The ACRS has not made any conclusion and still has quite a bit more to take a look at. So I want to make sure that people understand that's not an ACRS conclusion.

With that, I'd like to -- I believe that we have -- That does complete the NRC staff's presentation.

MR. GILLESPIE: Yes.

MEMBER WALLIS: Can I say something about this? I've been looking at the original data here from GPU and trying to figure it out and trying to see how on earth it's related to the stuff that was displayed in the Sandia study and it looks very interesting and I think they need to be put side by side so someone can explain to me how you go from the measurements and the places where it was measured to the actual numbers that were put into the computer program so we can understand that process and it's a believable one. Otherwise, there are just too many ifs and it may well be it's right. It looks to me looking at it superficially as if someone has made an effort to be conservative and take the lowest value and all that but it needs to be clearly spelled out.

MR. ASHLEY: In the final SER.

MEMBER WALLIS: Yes, and in the presentations I think too so that it's clear.

CHAIR MAYNARD: Yes, I think at some point the ACRS is going to have to have that information. That's something that we're going to have to be taking a look at before we're going to be able to make a determination and I don't think you're prepared to do that today.

MR. ASHLEY: No sir. I don't think so.

CHAIR MAYNARD: So with that, we'll -- I'm sorry. Did you want to make any concluding?

MR. GILLESPIE: No. I mean we'll make all the reports and everything that we have available and if there's a desire for us to come back or meet with a couple of the members and go through the matching of how we did the, how the Sandia staff did the Sandia report, we'll be more than happy to do that.

CHAIR MAYNARD: Okay. With that, it brings us to the next agenda item which is Public Comments and first on the list here is Paul Gunter from the Nuclear Information Resource Service. And I'll apologize to you for running late, but we can certainly give you your time here.

MR. GUNTER: Thank you. My name is Paul

Gunter. I'm Director of the Reactor Watchdog Project for Nuclear Information and Resource Service. My remarks are going to be very brief, just opening and then an introduction to Richard Webster who will conduct the presentation.

Nuclear Information and Resource Service first got involved with this when we looked at the Applicant's application and we were surprised that so much credit was being taken for the epoxy coating on the severely coated region and began our investigation which led to the filing of the single contention on November 14, 2005 before the Atomic Safety and Licensing Board with regard to an inadequate application in addressing the age management review of the drywell age management review process.

So essentially, six groups, five from the state of New Jersey and ourselves, intervened on this single contention and Rutgers Environmental Law Clinic has reviewed the contention and the filings of our experts and took the challenge up. With that, I would like to turn what presentation we're going to make today over to Richard Webster who is a staff attorney with the Rutgers Environmental Law Clinic in Newark, New Jersey. He has a BA in Physics at Oxford University, a Masters in Engineering in Hydrology from

Imperial College in London and a JD from Columbia Law School.

MR. WEBSTER: Thank you Paul and first of all, I would like to thank the panel for the opportunity to present here today. I don't see how I can do. I need to swallow the microphone here for a second.

CHAIR MAYNARD: We make them short so you have to lean in.

MR. WEBSTER: It's hard to watch the computer and do the microphone at the same time here. But I can chew gum and rub my stomach at the same time. So that's okay.

So what we've heard today has been very interesting and it's been very interesting to watch your reaction because your reaction has mirrored our reaction over the time. It's sort of this very slow revealing of information and each bit of information that you get actually adds to your concerns and the conclusion that we've come to now is that there are some very serious identified concerns. They cover both the current condition of the containment as well as the whether the containment could go beyond safety margins during any extended licensing period.

We characterize the process here as

putting the cart before the horse because if you don't know what the current margins are it's pretty hard to design an adequate program to figure out whether those margins are being maintained and at the moment, all we've heard from the Applicant is what we already knew which is that the monitoring has not been a time sequence and it has not been adequate in terms of space to really allow you to draw any definitive conclusions about the current margins.

Now let me just come through in more detail and I'm going to start with the embedded region because that's simpler because simply there's really no data. So we don't have to worry too much about the data there because there is none. And again our concern is about the current state of the embedded region and it's about the potential state of the embedded region during any extended licensing period. And similar concerns for the sand bed region. It's whether it meets safety margins now and whether any significant degradation in the future would be detected before safety margins are violated and that's actually, that fourth item, is the subject of our contention as well. So there is a limited scope of litigation here and that's what we're litigating as well.

So I think you've seen the diagrams. This is a bit of a bigger diagram of the containment and just to be clear then, this is the sand bed region.

CHAIR MAYNARD: I'm sorry.

MR. WEBSTER: Paul will point.

CHAIR MAYNARD: Stay at the microphone.

MR. MAYNARD: Paul will point to the sand bed region and then the embedded region is right below that. So we're talking about a small portion of a very large structure here, but a very significant portion.

Now normally our temporal look at this really starts and ends in 1992 because in 1992, they took the sand out. They couldn't look at the region very comprehensively before 1992 because the sand was there and there's that large concrete curb on the inside covering around two-thirds of the sand bed. So from the inside, all they really do is look at the top third and that led to the erroneous conclusion that this was called at the time a bathtub ring of corrosion. Actually, it wasn't a bathtub ring of corrosion. It was a bathtub ring of monitoring.

So then when they got in there in '92 and scrubbed it down, we did get a look at what was happening in there and what was found was very concerning. In terms of embedded region, the sand bed floor was unfinished, water had ponded on the floor, the floor had deep craters which is so far unexplained, but we think they are potentially due at least to corrosion or rebar in that concrete.

Until '92, there was no seal present between the shell and the concrete to reduce penetration of water in the gaps. Remember we have ponded water in this area. The fact that there's a seal there at all now tends to indicate there was a gap. So it seems highly likely that that water has penetrated into that gap and into the embedded region.

MEMBER WALLIS: Now this water that has ponded on the floor, that's inside the containment.

MR. WEBSTER: No, that's outside.

MEMBER WALLIS: Outside. When you say ponded, you mean outside.

MR. WEBSTER: I mean the outside floor by the drain stem.

MEMBER ARMIJO: You mentioned deep crater. Could you be more quantitative?

MR. WEBSTER: No, that's just taken from documents that we've seen.

MEMBER ARMIJO: You don't have any --

MR. WEBSTER: Paul, why don't you look up those while I'll continue? I'll get back to you. I think they're in terms of feet rather than inches.

MEMBER ARMIJO: In area?

MR. WEBSTER: In area.

MEMBER BONACA: And this is once you remove the sand. Therefore, it's a surface.

MR. WEBSTER: Right. This is the surface that's found once the -- Here we are. Here's the quote. Once the sand is removed, it reveals the concrete surface which has hitherto been covered up and it says the floor was cratered with some craters adjacent to the shell. A few craters were big, about 12 to 13 feet long and 12 to 20 inches deep and 8 to 10 inches wide.

MEMBER WALLIS: Twenty inches deep?

MR. WEBSTER: Yes.

MR. WEBSTER: And it says concrete reinforcement bars could be seen bare in many bays. So this certainly seems indicative that something's going on in this embedded region.

Now the other thing thinking about the sources of water, we've heard that there's quite a lot of wet areas in this plant affecting the wires and so forth. It hasn't been ruled out yet but some of this water down at the bottom could be from groundwater and we think that's a potential source of water that so far needs to be eliminated and we haven't seen anything that eliminates that.

Now corrosion is possible contrary to what the Applicant would like to believe. Our expert has assessed what the Applicant has put forward. He states the statement that the concrete generates a high pH environment, a pH of 12 to 13, and thermodynamic calculations reveal no corrosion of iron above 10 room temperature.

The latter statement is patently wrong. Thermodynamics clearly demonstrate that iron can interact with water over the entire pH range even more in the presence of oxygen. The rate of the reaction is governed by the protectiveness of the corrosion product layer. So from what we've seen and we've been provided with absolutely no expert evidence whatsoever from the Applicant about this issue and I don't know if the NRC has had expert evidence on this issue, but from what we've seen there absolutely is no justification whatsoever for an assumption that no corrosion could occur in the embedded region. In fact, the opposite it appears that it was wet, that there's at least some oxygen present at the top and therefore also the visual observation which we didn't know about until today is that the corrosion was just as bad at the bottom as it was at the top if not worse.

MEMBER WALLIS: Are you saying partly that if there are these craters in the concrete then the concrete will no longer protect the steel? Is that part of your contention?

MR. WEBSTER: No, what we're really saying is that the craters may have resulted from rebar corrosion and then once the rebar corrosion started to happen, that provides a way for the water to seep down into the --

MEMBER WALLIS: It provides channels for the water.

MR. WEBSTER: Right.

MEMBER WALLIS: Okay.

MR. WEBSTER: So the effects of sand removal ironically may have actually made this area worse. There's a phenomenon called differential aeration where actually in a crevice situation you don't need oxygen present to have corrosion occurring because electrons can be supplied through conductants of the surface and so actually you can get preferential corrosion of oxygen starved areas under certain circumstances. And it appears that that is possible here, but of course, it's never been verified.

So we're not saying it's certainly happening but it's certainly a possibility and it's a possibility that needs to be eliminated before any conclusions can be drawn about what's happening in this embedded region and what has happened in this embedded region prior to 1992 and in the 14 years since 1992. It actually astonishes us that this situation has gone unaddressed by the NRC for this long.

MEMBER WALLIS: Where does this 0.33 come from?

MR. WEBSTER: 0.33 is what was measured in the sand bed region. You're skipping ahead. It was what was measured in the sand bed region prior to the sand being removed. There has been no corrosion rate established. So we decided we would use that corrosion rate.

MEMBER WALLIS: For a year or just the total?

MR. WEBSTER: This is per year.

MEMBER WALLIS: For a year?

MR. WEBSTER: Per year. That was the maximum.

CHAIR MAYNARD: Did you get that from taking what the original thickness was and what the measured thickness was?

MR. WEBSTER: Right.

CHAIR MAYNARD: That's how you generated your --

MR. WEBSTER: Right.

MEMBER WALLIS: That happened in a year.

MR. WEBSTER: There were certain areas over time that that happened. That's the worst case and what we're saying is until a rate is established let's assume the worst case. I mean the Applicant it seems has the duty to establish a corrosion rate. They haven't done that yet. They've had this problem for -- They've known about this problem for at least 14 years and so far have done absolutely nothing about it.

So the steel thickness in the very lower region is 0.676 as we've seen. The thickness at the top is higher. It's 1.154 and just to be clear the corrosion rates in the sand bed region do not bound the corrosion rates in the embedded region because of this differential aeration phenomenon.

MEMBER SIEBER: Can I conclude from this that in two years you are corroded all the way through?

MR. WEBSTER: If that corrosion rate applied. We're not saying that corrosion rate does apply. We're saying the corrosion rate is unknown.

So I don't think it surprises you that we think some action is required here. We think there needs to be a comprehensive check of current thickness of metal in the embedded region. I'm very happy to hear Hans Asher suggest that the analyses does want some measurement of that region because that's certainly news to us as of today. But we think that the analyses has to be comprehensive. Looking at this problem though a keyhole is not going to produce the answer.

Second, I think this is very obvious. They need to monitor for wet conditions in the embedded region using electronic detectors. From what our expert tells us, it's quite possible to insert electronic detectors down there that register spacial resistance and that would actually give you some idea about whether the area is wet or not and it would actually bolster up the Applicant's aging inspections of this seal. I mean it's one thing to look at the seal, but what the Applicant said with regard to the component that was cracked is that visual inspection identified one crack and then 100 percent UT identified six cracks. That shows that visual inspection doesn't give you the whole answer. It gives you part of the answer. Once you see some concerns, it's time to go and do some real measurements and we have serious concerns already. So we think it's time to go and do some real measurements here. Let's just not sit around and argue about it on an academic position when there's a real problem out there and it needs to be solved and it needs to be solved urgently.

And finally, the Applicant needs to establish acceptance criteria for the measurements that they're going to take.

MEMBER WALLIS: You'd be in trouble using academic in a perjority.

MR. WEBSTER: I'm using it not in a perjority sense but merely in the sense that it's theoretical I should say. Remember I'm from Rutgers Law School. So we do have some claims of academia ourselves actually.

MEMBER WALLIS: Sometimes academic studies are better.

MR. WEBSTER: Absolutely.

MEMBER WALLIS: Thank you.

MR. WEBSTER: But they're not known for their urgency generally.

CHAIR MAYNARD: All right. Go ahead.

MR. WEBSTER: So now moving on to the sand bed. So that was basically a quick overview. I'm trying to move quickly here. So if you have questions, I know it's been a long afternoon, so if you have questions please stop me and ask me. But I want to move through this fairly quickly because it's getting to 5:00 p.m.

CHAIR MAYNARD: I think you've seen that the Committee is not shy.

MR. WEBSTER: Okay. So as we've heard in general in the sand bed, the most critical constraint is buckling. The modeling actually established three criteria and I was surprised to hear only two mentioned. There's one on the uniform basis. There's 0.736 inches of wall thickness. Of course, that's not very useful because the wall thickness isn't uniform. So it's kind of hard to apply.

There's a single point criterion which is no point should be less than 0.49 inches. Again, it comes back to a point made. I think --

MEMBER WALLIS: If it's seven inches buckling, it's not a point phenomenon.

MR. WEBSTER: That's right. That's actually a pressure bound phenomenon I think.

MEMBER WALLIS: Thank you.

MR. WEBSTER: But somebody made the point earlier that you can't just take the single worst measurement and say that's it. You have to do some extreme valuable statistics to actually figure out what the measurements are showing you. It could be the worst point value and actually we have done that for the Applicant because we're such nice guys. We decided to give them a little free work, a little free consulting work. So we've actually already done that for one small portion of the data just to illustrate the concept and show that it needs to be done more comprehensively.

And then originally this was all based on modeling of 36 degree slices of the shell. So there are ten bays, 36 degree slices and the problem with that is that there are two assumptions there. One is actual symmetry and the second was a spherical shape and it seems like now we have the Sandia study we've just heard about which is the first that we heard about it too has discarded the actual symmetry assumption to some extent but it does appear to retain the spherical shape assumption.

MEMBER WALLIS: Your concern is that if it's slightly off spherical that makes a difference.

MR. WEBSTER: Yes. So as I said, these are the problems with the established criteria. The sand bed is far from uniform as I said. It's actually described, the surface was described in the report, reporting the 1992 results as a golfball with dimples going in and out.

According to our structural experts who have again done some good free work for the Applicant, the symmetry assumption prevents the simulating anti-symmetric buckling. They actually said that it's possible that the bounding criteria is a combination of symmetric and anti-symmetric buckling, but a symmetric model can't model that. But I assume the Sandia model can. So I guess when we all hear all these caveats about what the Sandia model doesn't do I guess we're wondering which model does do what the Sandia model didn't do.

And finally the derivation of the small area criteria was not rigorous because, and I think the same problem actually applies to the Sandia study, you have to look at different geometries. Assuming a square area is not -- I mean it gives you some information but it doesn't tell you what the smallest area below a certain thickness could be to define the safety criteria. It appears that a horizontal gash for instance could be smaller but lead to a more stringent criterion although that's really just speculation. I mean nobody as far as I know has done any modeling to look at the effects of these geometries. But it just seems unlikely that a perfect square is the most bounding geometry. It seems much more likely that's been selected as a modeling assumption rather than based on some sort of review of what would be bounding.

Okay. So that's the first point then. The first point is that the established criteria really aren't rigorous. So we don't have any rigorous criteria for this shell as of now. That's the first problem because you keep asking me about the margin. I'm going to try and get to the margin but it's very hard to get to the margin when we don't even have acceptance criteria.

So the next problem is what about the measured results. The last measurements that were not in question were taken in '92. They were taken actually from the inside and from the outside. As we've seen, the inside results are very limited because they're limited to the top one-third of the sand bed. The problem with the outside results --

Well, let me give you what the results are. The smallest measure of result was 0.603 inches from the inside and 0.618 from the outside. So it's why I have an issue with the Sandia results is they don't even, let along extreme value statistics, represent what was measured and the second issue that results with those that results is of course there are error bars in those results. I mean that's what the result is but that doesn't show you what the worst could be. It's actually around five percent of all thickness error bar. So it's 0.03 for each single measurement just straightforwardly but the extreme value analysis should pull that through. But it hasn't been done yet.

And now the GE study looked at how assuming a 0.736 thickness shell could certain areas be below 0.736? Obviously the way it worked really in history is that the Applicant thought there weren't any errors less than 0.736 initially. So they modeled 0.736. But then of course some monitoring showed up some measurements less than 0.736 and then they started to say what can we do about that. And what GE did was they cut a square foot and took it down to 0.576 I think and had a look at that and what they found was as long as the area below 0.736 was less than one square foot in each bay, you could maintain the safety criteria. But if it went above one square foot, well, I'm not sure they actually tested it above. That's basically the limit of their conclusion that provided the area less than 0.736 was less than one square foot you would be okay.

Now I wasn't quite sure when Hans said four square feet because the Applicant's number that they quoted for the area below 0.736 is 0.68 square feet. The problem with that number is they haven't really measured this parameter at all. The measurements from the outside as we've just heard just took the thinnest spot. They didn't make an attempt to measure the area below 0.736 and the measurements on the inside cover around three square feet. There are 12 6"X6" areas being measured. So that covers three square feet.

Now we've put out the numbers that the total area was 300 square feet. In fact, we've heard from Hans today that actually the total area is 500 square feet. So from the inside, they are measuring less than one percent of the area. So they simply don't have any measurement of the area below 0.736 and that was something that was a bounding result in the modeling. So somewhere along the line, this acceptance criterion got lost and at the moment, I would like to -- I don't want to mischaracterize what Hans said, but it's startlingly worrying to me like the NRC believes that the area below 0.736 in bays one and 13 could be greater than one square foot. If that's true, we would be beyond the safety margins already.

MEMBER ARMIJO: I have a quick question for you.

MR. WEBSTER: Sure.

MEMBER ARMIJO: You say the smallest measured results was 0.603 from the inside and 0.618 from the outside. Now are those numbers that you took for the sand bed region?

MR. WEBSTER: Yes, these are all -- Everything relates to the sand bed region.

MEMBER ARMIJO: And this is an individual measurement not an average.

MR. WEBSTER: This is an individual measurement not an average. Just to take it up on the averaging, if you look into the averaging you'll find all sorts of problems there. I'll allude to them later but the statistical treatment of these results is a complete mess.

So the problem is each measurement is uncertain by about 0.03 inches and just to show you that the Applicant is fully aware of the extent of the error they actually accepted results that showed growth of, I said growth, in metal of 0.05 inches over two years. It was only when we analyzed the results and showed that that growth was systematic throughout the results and therefore could not be a result of random error but had to be the result of systematic, that the Applicant suddenly turned around and decided that there was an anomaly in those results. And actually the anomaly doesn't actually just extend 96. It also extends to 94 because that was done with the same methodology.

So these are quotes from Dr. Hausler who is our expert who you can imagine was kind of amazed to discover this. The general thickness for each grid decreases from 92 to 94. So you know first of all there's a claim that corrosion has been arrested. That wasn't what the 92 and 94 result showed. If those 94 results are valid, it actually shows some degree of corrosion even immediately after the coating was placed upon there.

The '96 results are the ones that Applicant relied upon to draw a conclusion of no corrosion. But those results systematically showed metal growth and Dr. Hausler coins this was of course physically impossible. Metal does not simply spontaneously get thicker and the Applicant has now agreed with him. But Amergan on June 20, 2006 admitted that the 1996 results were anomalous and as I said, the 1994 results are still not validates. The SER basically concludes that you can't rely on the '94 results either. As I say, if you could rely on the '94 results, the conclusion would be the corrosion was ongoing. So we really don't have any spatial tracking here of what corrosion is doing in the sand bed region. We might get some in October but at the moment the proposal as I'll show you later is very limited. I'm trying to stick right now to what we know about this thing right now. Is within safety margins right now?

So let's look at the margins that were established in 1992. Now remember this is 14 years ago. So we have serious concerns that you can't draw conclusions about the current situation based on these results. I mean it's been 14 years and we know that in 14 years at least over some periods of time water has been coming down this component. Again it's something that we recently found out.

So the single point margin was over estimated at 0.11 inches by the operator. Reanalyzing using extreme value statistics, the margin has been estimated by Dr. Hausler and this is based on '02 data which is a limited dataset. So I'm not touting this as the be-all and end-all of analysis. I'm just touting this as a starting point where we need to go and again you see that it comes to around 0.26 inches significantly less than had been estimated by the Applicant.

The small areas margin was estimated at 0.07 inches by the operator. Again, the problem with that is that he didn't look at the area below 0.736. That area is very sensitive to corrosion because the slope between the thin area and the thick area is relatively small and so a small amount of corrosion at the edge can cause a considerable expansion in the area. So based on an assumption of linearity and the transition between the thin area and the thick area, Dr. Hausler comes up with a margin of around 0.03 inches.

MEMBER WALLIS: What is the transition like between the thin and the thick area?

MR. WEBSTER: Well, we don't have that much information. I've seen a few very fuzzy photos that look sort of like moon shot photos and they seem to be sort of round, sort of like soup bowls they look like on the photo, but maybe the Applicant can elucidate on that a little more.

MR. ABDEL-KHALIK: What does this number pertain to, 0.07 or 0.03? Is this the margin?

MR. WEBSTER: This is the margin between -- In other words, this is an estimate of the amount of corrosion that would be needed to push the component beyond the code based on the current acceptance criteria which remember we don't think are actually correct. But they are the only criteria we have so we might as well use them just to scope out the problem and again I alluded to this before. The inadequate spatial scope, basically the curbs on the inside of --

MEMBER WALLIS: The basis of these claims he hasn't done a buckling analysis.

MR. WEBSTER: No, what he's doing is he's looking at -- He's taking the buckling analysis that GE did and he's looking at the criteria that they generated.

MEMBER WALLIS: Uncertainties or something and the statistics and all that stuff.

MR. WEBSTER: The statistics, he's looking at the measurements that Amergan have produced or at least the ones that they've released to us and is then running them through.

MEMBER WALLIS: But their analysis was correct.

MR. WEBSTER: No. He's taking their raw results and then rerunning the statistics.

MEMBER WALLIS: But he's assuming that they're mechanistic. Their stress analysis was correct.

MR. WEBSTER: Yes. I mean we don't think all of it is correct. We dispute. In fact, we think it is incorrect nonetheless because it fails to take into account some important phenomena. But nonetheless in the absence of any other, unlike the Applicant, we don't really have the funding to commission Sandia Labs to do a large study for us. So unlike the Applicant, we're just going to start with looking at what they have said would meet the safety requirements and then see how close they are and they're very close, very, very close. Although let's put it this way. They were very close in 1992. We don't know where they are now.

Remember each result has an uncertainty around 0.03. So you can see it's very hard to design a program and this is why we say it's the cart before the horse because it's very hard to design a program to measure thicknesses to this kind of tolerance going forward. If you don't know that you need to do that, then it's very hard to know whether the program is acceptable and that's why we really can't understand at the moment how NRC staff are drawing their conclusions about the acceptability of the program in terms of aging management.

Let me go over this. Basically, we've had consulting from stress engineers. What they've said is and I think what's coming out of this Sandia study which is that there isn't enough UT data to really do a good model on what's going on in this sand bed region. What they've said to us is it's routine these days in the oil industry to do a comprehensive scan of the whole vessel. When you get to close to margin, you do a comprehensive scan of the whole vessel, have thickness measurements for the whole vessel, measure the shape of the vessel and then actually use the finite element model as you were suggesting over here, actually put the numbers that you measure into the finite element model and then actually model the real situation and then you can start to look at margin by changing the amount, the thicknesses, of various areas where you suspect or you have some concerns that corrosion could occur and you see whether or how robust the vessel is. When you get close to this degree of margin, we fail to understand why do the most accurate techniques should not be used.

So here is the famous table. This is what I call the simplistic treatment of acceptance. You take all these results, you actually throw a few away in the statistical analysis because they don't meet normal statistics, you sort of fudge it around a little bit and then you compare what you label the current thinnest is, but actually isn't the current thinnest at all. It's some sort of average of thick and thin over a quarter of a square foot area and you compare it with a uniform criteria when the service is not uniform. This is absolutely not acceptable as a way to look at acceptance and this is what they're still doing.

Let me hasten to add this was taken from an old document, but this is still the process that the Applicant is using. So --

MEMBER WALLIS: Does this chart go back to GPU?

MR. WEBSTER: It does but it's the same numbers that are in Table 1 of the response that has been so much debated.

MEMBER ARMIJO: Actually they're different, but not all that different.

MR. WEBSTER: They're similar. They're similar in the common sense of the word. So in summary, we don't know what the current margins are. In fact, we don't even know if there are current margins. The acceptance criteria has not been updated. We know now that water has been draining from the sand bed at some time over the last eight years. Of course, we don't know when because the Applicant didn't actually do his monitoring as required and we don't actually know where the water came from because the Applicant threw it away before they got the chance to sample it and there is some suspicion that the water could be coming up from below.

MEMBER ARMIJO: I'd like to hear more why you think that's possible.

MR. WEBSTER: Well, we don't have a lot of data on that. I'm throwing that out as a possibility. I'm really throwing it out to be refuted by the Applicant. What we know is that the groundwater at this site is high, that this is at the bottom of the site, but I don't have a good view of what the relative elevations are between the wet areas and the non-wet areas. I would be very interested -- In the EPRI document that the Applicant has tried to rely upon but it's not a gold document, I think it's a EPRI document for their argument about the embedded region, it says that you should eliminate groundwater as a source of water and the Applicant actually hasn't done that. So if they're attempting to rely upon that document, they should at least do what it says in that document.

MR. ABDEL-KHALIK: But the elevation at that point is 8'11" or so.

MR. WEBSTER: Of the embedded region.

MR. ABDEL-KHALIK: Right.

MR. WEBSTER: I'm not quite sure what the relative dating is on that. Is that --

MR. ABDEL-KHALIK: Wouldn't that be sea level?

MR. WEBSTER: I don't know. I mean I don't know. I'm throwing that out as a possibility to be refuted.

CHAIR MAYNARD: I think your point is that you don't have evidence that it is groundwater, but you haven't seen any analysis or enough information to rule it out.

MR. WEBSTER: That's right. We're saying

it's a cause that they should rule out. It's sort of illustrative that a root cause analysis is woefully inadequate or at least somebody should have looked at those elevations and figured it out.

Visual monitoring of the epoxy coat, again this is according to our expert the epoxy coat visual inspection is really not sufficient. He says that visual examination needs to be augmented by more quantitative assessment. Holidays and pinholes in the coatings cannot be addressed by visual examination. The coatings industry have developed methodology which can more accurately establish the integrity of coatings and he actually references four methodologies that are designed to analyze the integrity of coatings.

Of particular important is integrity of the putty. This is the seal in the embedded region. Water leakage in the crevice will further stimulate corrosion below the sand bed and floor. We think the coating should be inspected quarterly while wet conditions prevail and at the onset of moisture being detected.

Now I was astonished today to hear that half of the bays haven't been inspected at all. When GPU Nuclear applied that coating they estimated its useful life was ten years. We're now 14 years later. So what that means is we're four years beyond the estimated life and half the bays are not being inspected at all. We've heard that the corrosion is quite heterogeneous, that what happens in one way doesn't tell you what's happening in another bay. So if that's the case I don't see any justification at all for the failure to monitor five bays to date.

And so finally -- Oh yes. The UT measured area was not adapted to thin areas at the edges. So in other words, when they did their 6"x6" area if the areas at the edges were thinner than 0.736 they didn't then expand the area and keep going to define the area that was thinner than 0.736. They just stopped there.

And as we know, they didn't measure known areas that are thinner than 0.736. That scatter plot that I think, Dr. Wallis, you were looking at from the 1992, I should have put that on my slides, assessment shows a scatter of thin areas all over the shell and there was no effort to measure the area of those thin areas. The only measurement was the thinnest spot on those areas which I think was -- I mean I don't know exactly the temporal sequence but certainly once the GE modeling was available for those small areas, I think it behooved someone in either the NRC or the operator to go out and measure those areas because those could be absolutely critical.

My clients are amazed here of the oversight situation of this reactor. We have a situation and we really have no idea right now what the situation is, what the margins are and whether they're meeting the code or not. As far as my client is concerned, that's really not remotely acceptable.

So single UT measurement uncertainty is very close to the margin. So the operation fails to fully account for uncertainty and finally, there is insufficient data therefore to calculate the area below 0.736.

So that's what we don't know about the current situation really. So given what we don't know about the current situation it's pretty hard to predict what we're going to be able to do in the future. At best we can say that the predictions of the future are highly uncertain and that to determine the appropriate monitoring in terms of spatial scope and the required accuracy, we need to know the current margin to a high degree of certainty and the only way we're going to know is that we're going to use the most accurate techniques as proposed by Stress Consulting.

And to determine the monitoring frequency we need to look in a very systematic way at corrosion conditions. Let me come through these in more detail. We need to estimate the worst case corrosion rate which we had some questions about before. We're using a very high corrosion rate. I probably don't think that's realistic.

MEMBER WALLIS: This is your 0.33 inches per year.

MR. WEBSTER: Right. I don't think that's realistic but I don't think there's any other number out there. So you want to take the biggest one and again it's a question of should this be a process of elimination as far as we're concerned. Let's start with the worst case assumption and work our way in; whereas the Applicant has done absolutely the opposite. They've started with the best case assumption, zero corrosion, and said can we show zero corrosion is okay. They're struggling to show that.

So the proposed program is inadequate. What they proposes for the next outage is that they will measure or at least what they proposed in writing in their June 20th commitment is that they will measure the areas from the inside that they measured before. So it will twelve 6"X6" areas in the top area of the drywell, of the sand bed region of the drywell, totally inadequate to even compare to the current acceptance criteria.

The statistical techniques as I said before using the data analysis are completely flawed and I will go into more detail on that. The coating integrity as I said hasn't been adequately maintained. There are tests out there. They should be done both immediately after it's applied. I was again interested to hear that again one reason that there wasn't an aging problem was because it was an installment problem. For this coating, I mean we don't know whether it was an aging problem or an installation problem because they didn't properly measure it after they installed it and they haven't measured it since. So I don't know how splitting the hairs about which kind of problem it is doesn't mean it's not a problem. The fact is they haven't looked, they haven't made sure this installation was done properly and they haven't looked systematically at whether it continues to be functional. In fact they haven't looked at all in half the bays about whether it continues to be functional.

And then finally, the initial UT monitoring proves it every four years. I don't know how anybody came up with four years. I mean if you're going to have any kind of corrosion rate I don't understand how you can calculate four years. The idea that the upper region bounds the corrosion rate is completely wrong. The temperatures are much higher in the upper region. That means that it's less likely to be wet or at least the moisture will evaporate more quickly and then there's this firebard D stuff in the upper region which isn't present in the sand bed region. So I don't think the results in the upper region, they are always much smaller in the sand bed region, the corrosion rate there. So it's a datapoint out there, but it certainly doesn't bound the sand bed region in any way at all. And I'm amazed that that would even be put forth as an idea. It doesn't seem to make sense to me.

So finally, we must build in fail-safe checks. What we've seen from the Applicant's failure to meet its commitments is that when you just rely on one commitment for safety if they miss on that commitment, you have a safety problem or you potentially have a safety problem at least. We strongly believe that there have to be fail-safe checks, multiple systems in place, to make sure that if we have a margin on this drywell that it's maintained.

Okay. I think I'll skip over that one. Statistical techniques, there was some interest in that. The first problem is that the potential for future corrosion is not estimated when no corrosion is measured. It's just an assumption that we didn't see any corrosion in the past. It won't happen in the future. I've never seen any justification for that. So I'm sure now we know given the error bars that it could be it's a sampling artifact that you see no corrosion or it could be that the conditions could change in the future. So the past conditions are not indicative of future conditions necessarily. So you have to really look at the propagating error bars going forward to see what's happening even when you see no corrosion.

MEMBER WALLIS: These are two measurements side by side.

CHAIR MAYNARD: Wait. Listen to the remarks here.

MEMBER WALLIS: I'll talk to him.

MR. WEBSTER: So secondly -- Do you want me to continue? Secondly there's an erroneous assumption of linearity over time. In fact, it's quite possible for pit corrosion to accelerate over time. So this projection of linearity again no justification again whatsoever for that.

Again there's an erroneously assumption of unchanged conditions. I mean if you're monitoring every ten years but the corrosion could happen in four years or three years or two years, then the monitoring every ten years is inadequate and at the moment, we think it's possible that the corrosion could happen very quickly especially in the crevice corrosion of the embedded region. And there is just absolutely no data out there on it. So we think you have to be conservative. Once every ten years doesn't seem very conservative to us.

This 95 percent confidence interval, this is again another mystery. I mean this means that basically there's a potential violation of the safety margin one and 20 times for this kind of confidence interval. Now we've seen no analysis of how that projects forward into a safety calculation and I think if you're going to accept that kind of low bound of certainty for a safety significant component, you really have to show rigorously that it doesn't translate into some kind of safety problem and that just simply hasn't been done. As far as we can tell, somebody got their statistics textbook out, saw 95 percent as a standard interval and just started messing around with that.

Confirming that view, somebody tried to use normal statistics. The problem with normal statistics of course is it's generally two-sided and there are various assumptions built in. Here you really need a one-sided distribution and our expert has recommended a couple of distributions that might be more appropriate. The fact that the normal distribution is not appropriate was really found by the Applicant. They kept analyzing the results and checking that the normal distribution was right and finding it wasn't. So their response instead of saying we go the wrong distribution here was to discard data and to divide the data into different subsets in a desperate attempt to fit the data back to a normal distribution. When any reasonable statistical view would have been this distribution is not working. Let's change distributions. You really can't -- You have to really see what the data is telling you and just cherry-picking the data to fit into a distribution doesn't seem as of our expert to be a very rigorous scientific approach.

They failed to look systematically -- Yes, I mentioned the data filtering. I want to emphasize that again. In certain cases, we see data being discarded, pits being taken out because they don't fit normal. In fact our expert is saying that's precisely what you expect to see when corrosion is happening. Certain pits go very deep and they are way beyond three standard deviations. But those pits are precisely the ones you have to worry about most not the ones you should throw away when you're doing your data analysis.

MEMBER WALLIS: These are pits in the shell.

MR. WEBSTER: Yes, they are pits in the shell. Yes.

MEMBER WALLIS: Not pits in the --

MR. WEBSTER: No, they are pits in the shell.

So they fail to look systematically at uncertainties in the measurements. When you see an estimate about the square footage of area below 0.736, you really have to ask yourself what is the uncertainty. Given the uncertainty on each individual measurement, the uncertainty on that is very likely to be high and we think that the modeling needs to reflect that worst case assumptions, i.e., what could be the case right now. We really think on a modeling study what you need to do is to look at what could be the case right now given the variation, given the uncertainty in the results and then what could be the case in the future given the time intervals and the potential corrosion rate. So far, nothing like that has been done.

And again, we keep coming back to this. We were been unable to estimate a corrosion rate right now because we really have one datapoint in the sand bed region since the sand was removed. That's in 1992 It's very hard to get a rate out of one point. And the problem -- Well, when next results we'll have two points, but the problem is because there's been no monitoring conditions during the time that the two points have been occurring we really have no idea how the conditions will translate into a corrosion rate. And we would like to see a corrosion rate under wet conditions, a corrosion rate under coating failure conditions and so forth. We just don't have the data to even approach thinking about that kind of approach.

So here we are. This is an emphasis on maintaining coating integrity. I think I've said this. Basically, visual inspections as the Applicant itself has admitted today misses a lot of details. It's quite possible for pinholes and holidays to occur. Water gets in behind those. You get corrosion happening behind those and actually then the coat can mask that corrosion is occurring.

And again because it's so close to margin you don't need a whole lot of corrosion to get to be on the margin. So we believe that visual inspection must be augmented by the industry standard objective measurements. We believe that when wet conditions prevail the monitoring frequency must increase to at least quarterly until more certainty prevails. And we believe that a response to coating failure must be a complete renewal of the coating and comprehensive UT measurements within a quarter.

At the moment, they're proposing if they see a small area of coating degradation they will basically fix that area, but not fix the other areas and it seems to us that once the coating starts to go that's indicative of the whole coating needs to be renewed.

MEMBER SHACK: Just the statement was made that the ASTM standard calls for visual examination. What industry standard are you referring to?

MR. WEBSTER: Let me just check for you. National Association of Corrosion Engineers International Standard Test Method TM00384, Holiday

Detection of Internal Tubular Coatings of 2.5 micrometers film thickness. Again, National Association of Corrosion Engineers Standard No. --

MEMBER SHACK: What was that standard number again?

MR. WEBSTER: TM00384.

MEMBER WALLIS: Could you explain what a holiday is?

MR. WEBSTER: A holiday, I don't think it's used in the English sense. I think it's a small hole. It's a place where the coating didn't apply in other words. I think it's a place here the coating, when you are brushing the coating on or however you're applying it, you missed a spot. The brush sort of took a holiday.

MEMBER WALLIS: It didn't stick.

MR. WEBSTER: It didn't stick. Your brush was on holiday for that particular spot.

I can give you these codes later. They're all in Dr. Hausler's --

CHAIR MAYNARD: If you could give him those codes later. I am giving you extra time.

MR. WEBSTER: Yes.

CHAIR MAYNARD: We do need to move along.

MR. WEBSTER: Let me wrap up then. So the monitoring for water, at the moment as we said, as Amergan said, you know they promise they're going to look at these drains in the future although they didn't the past and what we're saying is you know there are electronic water detection systems out there. They would give you a lot more detail about where the water is, when it starts to happen and for how long it happens. You actually end up with an objective measure. You end up with a log and you get just a lot more information out of this. Again I don't quite understand why this hasn't already been proposed. When you're this close to margin and with a component of this significance, it seems to us that you should do the best you can not just try and get away with the least and I'll let you slide by me.

Monitoring frequency basically at the moment, it's really very hard to know what the monitoring frequency would be appropriate because the safety margins are not established and the worst case corrosion rates are not known. So as I said we advocate conservative assumptions. And again we strongly believe that we must have fail-safe intervals. We must have fail-safe systems all around because we cannot just rely on this Applicant meeting all of its commitments all the time.

Finally, and importantly, Dr. Hausler raised another possible failure mechanism, chloride induced fatigue cracking and suggested that that must be examined and ruled out and as far as we know, nothing has become of this suggestion.

Oh, I should mention. This information Dr. Hausler provided was provided directly to the NRC. It wasn't provided as part of the litigation. So this is -- Actually, strike that. I think that's incorrect. That was provided as part of litigation.

MEMBER ARMIJO: Do you have any literature, documents, that cite chloride stress corrosion cracking in carbon steels?

MR. WEBSTER: I haven't seen any. I will certainly ask Dr. Hausler that question if you would like me to.

MEMBER SIEBER: What's the pathway for the introduction of chlorides? Where does it come from?

MR. WEBSTER: I'm not sure at this point. I can again check for you. So the Chairman will be pleased to see that this slide is labeled conclusions.

MEMBER WALLIS: You keep referring to Hausler's report. Has this been given to the NRC?

MR. WEBSTER: These have all been filed with the Atomic Safety and Licensing Board.

MEMBER WALLIS: Has NRC seen this work yet?

MR. WEBSTER: I believe they have.

MEMBER WALLIS: They have. Okay.

CHAIR MAYNARD: It was filed as part of litigation.

MR. WEBSTER: Some of the memos have been filed as litigation and some of the memos because we were actually prevented from raising the issue of embedded corrosion in the litigation we've actually filed these separately to the staff just in order to help their review.

MR. GUNTER: I just wanted to say that I apologize but we did provide all of Hausler's memos last week. So I don't know if you've actually had a chance to review those materials yet. But the ACRS does have them.

MEMBER WALLIS: No, absolutely not.

MEMBER SIEBER: Filled up a section of my hard drive.

MEMBER WALLIS: We have a lot of other things going on too.

MR. WEBSTER: I'm sure you do. My hard drive has been filling up too. So in summary at the moment we don't have a current reasonable assurance of safety. I think that's hard to dispute. We know that the proposed monitoring program is inadequate. There are more measurements scheduled this month and if they were comprehensive they could answer many of the questions that have been raised here. The problems is at the moment they're not comprehensive.

At best the conclusions about future safety of the shell and the SER and the inspection port are premature. I mean at a minimum we have to wait for these results, but the problem with the results is that because they're not comprehensive, they really won't solve most of these problems. So what we need to do here, what's happening really in this problem, when you look at it from stance of what's really happened is that a whole bunch of assumptions have accumulated over time, sort of cluttered up the thinking on this program over time. People kept going back and saying the NRC accepted this before so it must be okay and then tried to use what has been accepted before as a guide to what will be done in the future.

And the reality is we have serious questions about what was acceptable before should have been accepted before. What we know is it's certainly unacceptable going forward. Until we get a rigorous quantitative analysis based on comprehensive data and careful consideration on certainly, we strongly believe we encourage the ACRS to wait on this application until you really see and are really satisfied that this problem has been addressed in a very rigorous manner. I think any careful analysis of the data will show you right now that the analysis that's been done is far from rigorous, is far from adequate and we end up in a situation now where elected officials have written to the NRC last week asking how the NRC can conclude that this reactor has a reasonable assurance of safety and that's all I have to say. Thank you very much for your time.

CHAIR MAYNARD: I really appreciate your comments and the ACRS I assure you has not come to conclusions on this. I think you can tell from our questions and we will be using your comments and information that you've provided here. We'll be factoring that into our future evaluation, deliberation, of this particular license renewal application and take that in conjunction with other information that we have and I'll assure you that the ACRS will not make a decision or recommendation until we have answers to the significant questions that we still have outstanding too. I appreciate your comments there.

MR. WEBSTER: Thank you very much.

MEMBER BONACA: I have a question that I would like to ask.

CHAIR MAYNARD: Okay.

MEMBER BONACA: It has to do with do you know specific techniques that could be suggested to do the direct measurements of the embedded thickness, metal thickness?

MR. WEBSTER: The short answer is no. I mean it seems that there are some research reports out there that the NRC has cited and the other approaches that chip out the concrete and get down there. Beyond that there's nothing really. There's no magic bullet out there as far as we know.

CHAIR MAYNARD: What I would like to recommend to the subcommittee here if I could have your attention here. It is getting late. I believe that we still have a number of questions, a number of unanswered questions. I'm not sure that it would do any good to bring the licensee back up here and the staff and reask a lot of the same questions. I think we need to take a look.

I would recommend that tonight we give this some thought. We have an open meeting session tomorrow of subcommittee time and I think at that time we can discuss what we believe our next step should be. There are several options available, another meeting, request additional information, define what needs to be provided or whatever but unless somebody objects to that I would recommend we give it some thought overnight and discuss it in open meeting tomorrow under subcommittee report as to what our next step is.

I believe I'm safe in saying that we all still have a number of questions that we don't have answers to yet. Right?

MEMBER BONACA: I do.

CHAIR MAYNARD: Okay. With no objections, that's it.

MEMBER WALLIS: That's the end. No more presentations.

CHAIR MAYNARD: We have no more presentations and we're out of time. So with that, I would like to express my appreciation to all the presenters and everybody that participated and I appreciate your patience and we will conclude this meeting. The meeting is adjourned. Off the record.

(Whereupon, at 6:11 p.m., the above-entitled matter was concluded.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee

Docket Number: n/a

Location: Rockville, MD

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

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.

From: Bill Hering <bill.hering@smelectric.com>
To: "'cxs3@nrc.gov'" <cxs3@nrc.gov>
Date: 10/03/2006 11:09:36 AM
Subject: OYSTER CREEK

Gentlemen, Thank's for the opportunity to comment on the Oyster Creek license application regarding the meeting in Rockville this afternoon.

My history with Oystercreek goes back many years, and briefly, my background is 40 years active in the IBEW construction trades - Current today LU 164 Jersey City - and I am a professional Occupational Safety & Health Trainer with the US Department of Labor both Mine Safety and Health Administration and OSHA - Past President of the American Society of Safety Engineers New Jersey Chapter 1999 / 2000, and I was the Project Manager 15 years ago when we built the Nuclear Simulator at Oyster Creek, and the Safety Manager overseeing the Homeland Security upgrade with the electrical contractor, two years ago, at the Oyster Creek facility.

My Comments are first 100% in favor of License Renewal, based on every single thing I had the opportunity to see and be part of with this facility. Yes, it's the oldest facility, but gentlemen, the safety record based on industry standards is impeccable. For that matter, the Nuclear Industry has had a fabulous record in the entire country, thanks to the oversight by the NRC and committee's as your's.

If the various components of this plant are meeting these industry standards and with new technology constantly at our doorstep to enhance these safety benchmarks, we need to have a common sense approach to these re-newals for this industry. Various opponents to this application and other plants operations seem to have a mission which is either to far right or to far left... I'll leave that to your judgment...in short this plant is a safe reliable source of 650 megawatts of clean electrical energy that is in dire demand in our state.

The license process by statue is 20 years - HOWEVER - I believe that perhaps in 5 years or so, a new type reactor will be finalized and hopefully replace older reactors on all Nuclear sites in the future in our great nation.

Another very interesting point is that recent polls concerning the license renewal of Oyster Creek have shown independently over 80 % of those from 5 miles, 10 miles and the State as a whole have registered IN FAVOR of the plants license renewal.

As far as homeland security, this plant has the latest in technology as I witnessed it being built and certified.
The spent fuel is on site either way, so again - common sense - let's keep the plant running as the spent fuel will be there anyway for some time until all the bug's are cleared with YUCCA Mountain and security will need to remain in tact.

I think I've said enough. Gentlemen, PLEASE TAKE ALL THESE POINTS INTO CONSIDERATION AND UNDERSTAND THAT THE NEGATIVE COMMENTS SEEM TO ONLY REPRESENT A SMALL MINORITY OF OUR POPULATION, WE NEED NOT ONLY RELICENSE EXISTING, BUT BUILD MORE NUCLEAR Facilities ASAP AS THE NEED FOR CLEAN

ENERGY IS RISING RAPIDLY

Nuclear Power is a super high priority in this unstable energy market world. Give this plant a chance to continue to be a viable producer in this essential energy market and the electrical grid in general.

Thank's again for your accepting my comments,

William E. Hering
1005 Peaksail Point
Lanoka Harbor, NJ 08734
609 971 0930

CC: "'laceyclerk@comcast.net'" <laceyclerk@comcast.net>

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Oyster Creek License Renewal Presentation to ACRS Subcommittee

October 03, 2006

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AmerGen Representatives

- Michael Gallagher, Vice President, License Renewal Projects
- Timothy Rausch, Vice President, Oyster Creek
- Fred Polaski, License Renewal Manager
- Tom Quintenz, Site Lead License Renewal Engineer
- John Hufnagel, Licensing Lead

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Agenda

- Description of Oyster Creek
- Current Plant Status
- Operating History
- Drywell Corrosion
- NRC Open Items
- License Renewal Methodology & Results
- Commitment Management
- Status of Program Implementation
- Summary

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Description of Oyster Creek

- Located in Lacey Township, Ocean County, NJ
- Barnegat Bay is Ultimate Heat Sink
- GE BWR 2 with Mark I Containment
- Interim Spent Fuel Storage established onsite
- Overall CDF
  - Internal events: 1.1E-05/year
  - LERF: 5.8E-07/year

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Current Plant Status

- Operating in 20th cycle
- Transitioned to 24 month cycles in 1991
- Currently operating in end-of-cycle coast down
- Regulatory Oversight Program (ROP) status

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Operating History

- Full (Original) Design Power Level – 1930 MWth
- Commercial Operation
  - April 1969 Provisional Operating License (POL) issued
  - Aug 1969 Authorized to 1600 MWth
  - Dec 1970 Authorized to 1690 MWth
- Current Licensed Thermal Power 1930 MWth
  - Authorized in November 1971
  - No power uprates performed or planned
  - Design electrical rating 650 MWe
- Full Term Operating License
  - Issued July 1991
  - Expires April 09, 2009

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Drywell Corrosion

- Background
- Initial Corrective Actions
- Verification of effectiveness
- Initial Aging Management Program
- Enhanced Aging Management
- Conclusion

Background

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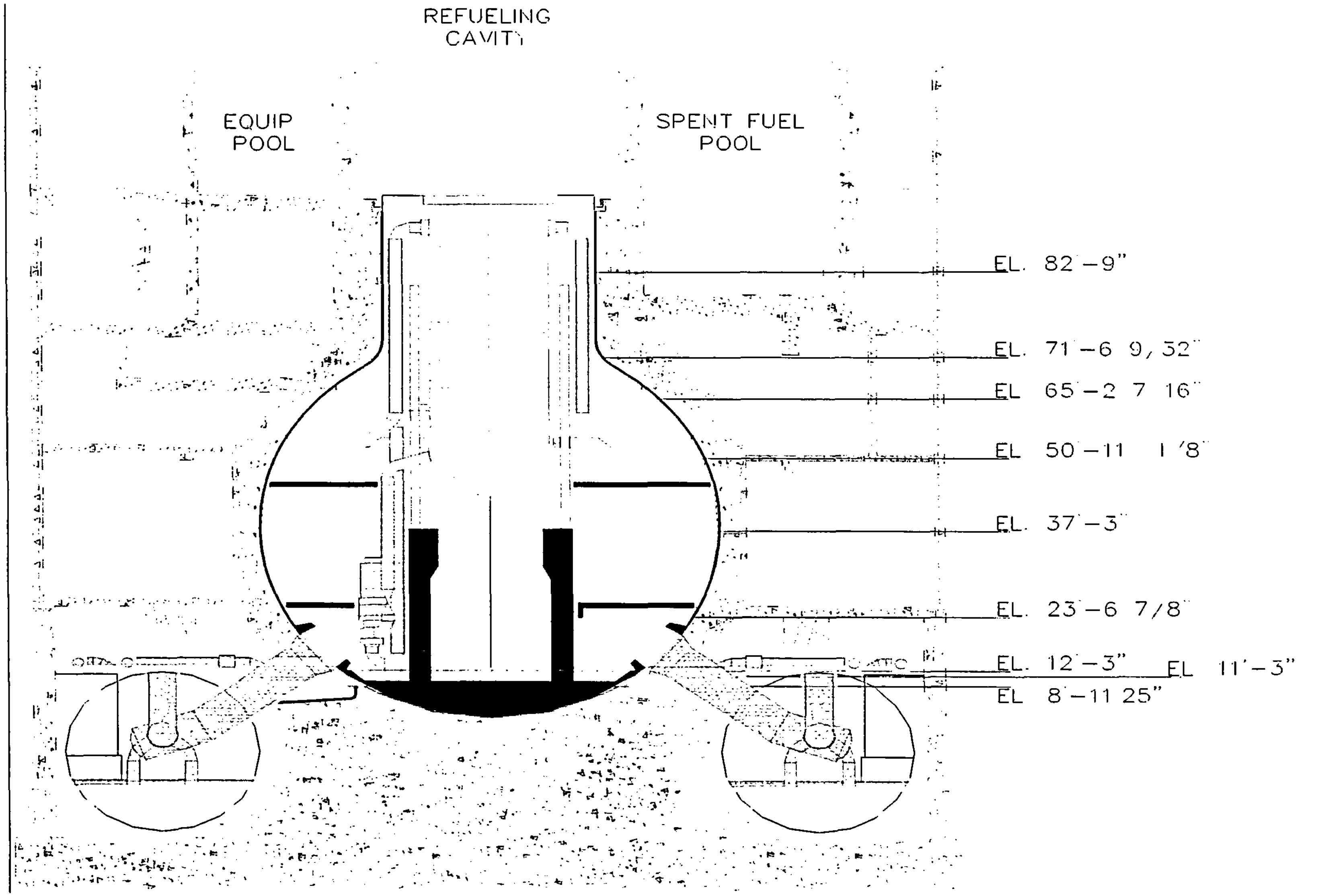

Sand Bed Area

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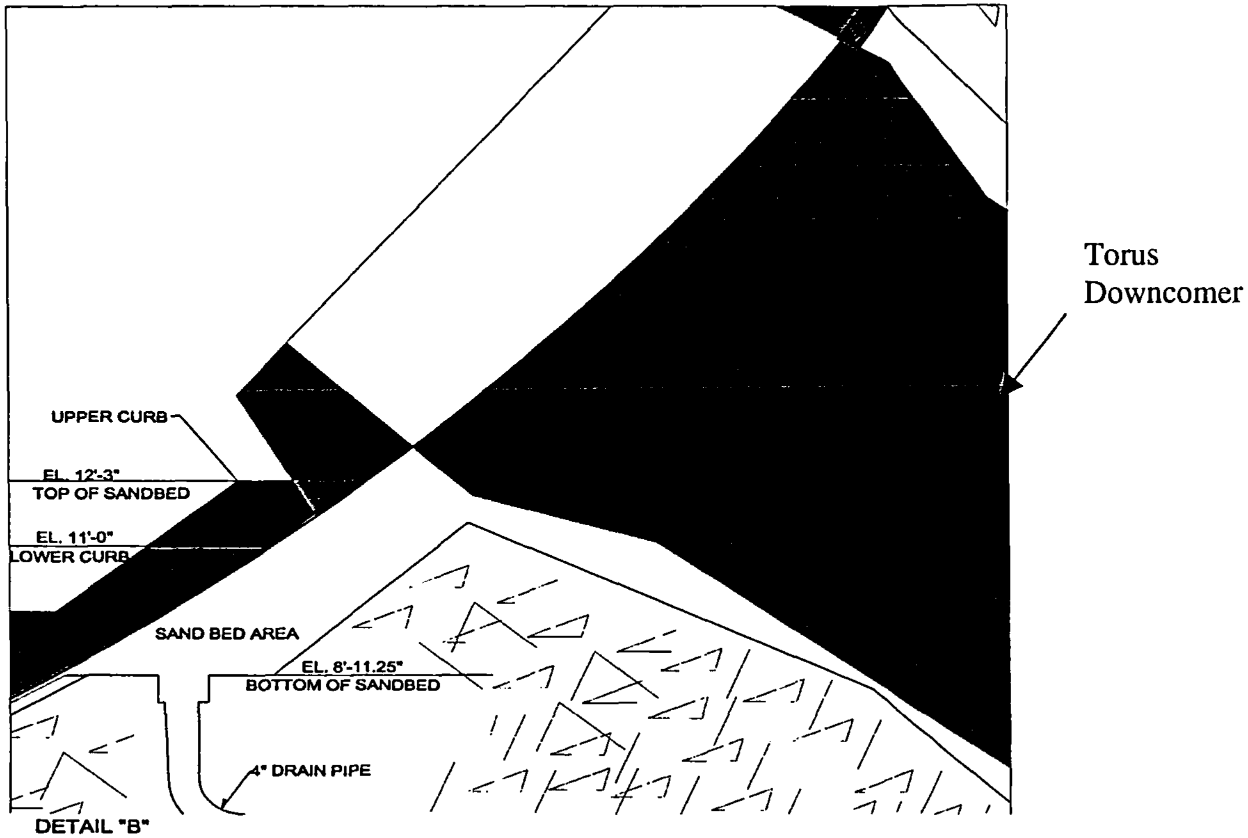

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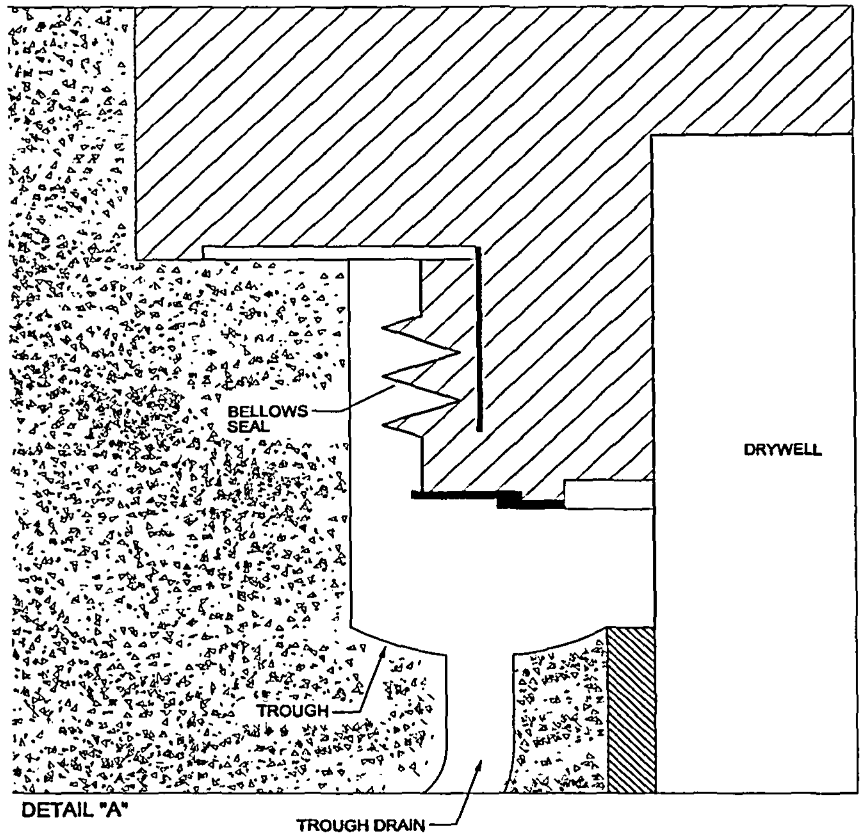
Reactor Cavity Seal Area



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Liner Corrosion Identified

Mid 1980s

- Water leakage into the sand bed region was identified during refueling outages.
- The source was determined to be from the reactor cavity through the gap between the drywell and the reactor building, down to the sand bed region within the reactor building.
- The sand bed drains were clogged.

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Initial Corrosion Monitoring Activities

Post Mid 1980s

- Approximately 1000 UT Measurements taken to identify thinnest locations in sand bed region and upper elevations
- Core samples were taken to confirm UT measurements
  - Also confirmed that the mechanism is general corrosion
- Random UT Inspection Plan was implemented to verify adequacy of measurement locations
- Staff accepted the program in November 1, 1995 SER

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Corrective Actions Implemented

Early 1990s

- Containment Peak Pressure was reanalyzed to establish additional shell thickness margin
- The minimum acceptable shell thickness was determined
- UT measurements were taken to verify minimum thickness with margin
- Water leakage source was reduced
- The sand was removed from the sand bed region
- The sand bed drains were cleared
- The drywell shell in the sand bed region was coated

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Corrective Actions Determined to be Effective

1994

- UT Measurements in 1992 and 1994 confirmed that the corrosion was arrested in the sand bed region
- 1996 UT measurements contain uncertainties – UT in 2006 will again confirm corrosion arrested
- Visual inspections of the coating were also performed

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Initial Aging Management Program

Established in Early 1990s

- Upper drywell UT measurements taken every other refueling outage
- Visual inspections of the sand bed region drywell shell coating performed every other refueling outage

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Aging Management Program
Enhanced in 2006

- Strippable coating for Reactor cavity
- Monitoring for water leakage
- Upper Drywell Shell UT measurements every other Refueling Outage
  - Leading corrosion indicator
- Sand bed region Drywell Shell UT measurements before PEO, then after 4 years and then every 10 years
  - NRC will be notified within 48 hours of any deviations outside expected results
- Sand bed region Drywell Shell coating visual inspections before PEO and 100% every 10 years

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Conclusion- Drywell Corrosion

- The corrective actions to mitigate drywell shell corrosion have been effective.
- The drywell shell corrosion was arrested in the sand bed region and continues to be very low in the upper drywell elevations.
- We have an effective aging management program to ensure continued safe operation.

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NRC SER Open Items

- Adequacy of sample size for UTs at drywell shell plate thickness transitions
- Potential corrosion of embedded shell
- Impact of corrosion on strength of drywell shell related to buckling analysis
- Use of ASME III Subsection NE-3213.10 for analysis of (localized) thin shell areas
- Extent of follow-up exams of coated sand bed surfaces if leakage is detected

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Operating History

- Reactor Vessel Internals
  - Core shroud
  - Core Spray spargers
  - Top Guide
  - Control Rod Drive Stub Tube
- Electrical cable
- Underground piping

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License Renewal Methodology

- LRA submitted July 22, 2005
- NEI 95-10 Rev. 6 Standard Format
- Prepared using NUREG 1800 (SRP) and NUREG 1801 (GALL) January 2005 draft revisions
- AmerGen prepared a reconciliation document comparing the Oyster Creek LRA to NUREGs 1800 and 1801 Rev. 1.
- A third AMP/AMR audit week was added to the review

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Aging Management Programs

- 50 GALL programs
  - 18 existing
  - 14 existing requiring enhancements
  - 18 new (11 associated with Forked River Combustion Turbines and 1 with Meteorological Tower)
- 7 Plant specific programs
  - 2 existing
  - 2 existing requiring enhancements
  - 3 new (1 associated with Forked River Combustion Turbines)

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Forked River Combustion Turbines (FRCTs)

- The FRCTs are 2 peaking combustion turbines, 38 MWe each, installed in 1989
- Owned and operated by First Energy
- Credited as the Alternate AC power supply for SBO in 1992
- Covered by Maintenance Rule and Surveillance Testing Programs

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FRCTs

- Demonstrated high reliability (>99%) formed basis for initial aging management strategy
- LR application credited reliability monitoring as the aging management program
- After discussions with NRC, AmerGen elected to establish multiple GALL-based AMPs to manage aging of long-lived, passive components

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Commitment Management

- All 65 commitments are listed in Appendix A of the application.
- A Passport commitment tracking number has been issued for license renewal commitments
- An associated action containing the details was issued for each of the commitments
- Each implementing procedure is annotated to provide linkage to and preserve the details of the commitment
- Process controlled by the commitment management procedure

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Status of Program Implementation

- 257 new and 111 enhanced implementation activities identified
  - 13% in 2006 refueling outage scope
  - 19% in 2008 refueling outage scope
  - 68% to be performed on-line

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Summary

- Aging Management Programs are established to ensure safe operation for period of extended operation
- License renewal commitments are tracked and will be implemented as expected
- On track for completing activities prior to entering period of extended operation

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Questions?

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Subcommittee

Oyster Creek Generating Station

Safety Evaluation Report with Open Items

October 3, 2006

Donnie J. Ashley, Project Manager
Office of Nuclear Reactor Regulation

Introduction

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

Overview - Status

- LRA submitted by letter, dated July 22, 2005
- LRA based on January 2005 GALL
  - Reconciliation document submitted
  - Reconciled to September 2005 GALL and SRP NUREG1800 and 1801
- SER issued August 18, 2006
- Five Open items and no Confirmatory Items
- 3 license conditions
- 108 RAIs issued, 366 audit questions
- One major component had expanded level of detail – Forked River Combustion Turbine (FRCT)

OI Cond

Overview – Audits and Inspections

- Scoping and Screening Methodology Audit
  - September 15 - 19, 2005
- AMP GALL Audit (started)
  - October 3, 2005
- AMP/AMR GALL Audit
  - January 23, February 13, and April 19, 2006.

- Regional Inspection
  - March 13 – 17 and March 27 - 31, 2006

Section 2: Scoping and Screening Review

Section 2.1 - Scoping and Screening Methodology

Section 2.2 – Plant-Level Scoping

Section 2.3 – Mechanical Systems sys

Section 2.4 – Containment, Structures, and Supports strs

Section 2.5 – Electrical Components and Commodity Groups

Section 2: Scoping and Screening Conclusion

- Scoping and screening results included all SSCs within the scope of license renewal and subject to AMR

License Renewal Inspections

Michael Modes
Region I

License Renewal Inspections

- Two–week onsite inspection during March 13 to March 17 and March 27 to March 31, 2006
- Scheduled to support NRR reviews
- Team of eight inspectors
- Inspection performed in accordance with NRC Inspection Procedure 71002

License Renewal Inspections

- Scoping and Screening
  - Concentrated on non-safety systems whose failure could impact safety systems
  - Emphasized physical walk downs of the plant
- Conclusion
  - Methodology was adequate and consistently applied

License Renewal Inspections

- Aging Management
  - 30 aging management programs plus 2 time-limited aging analyses
  - Focused on one system: Isolation Condenser
- Conclusions
  - Applicant implemented existing aging management programs as described in the application
  - Applicant provided acceptable enhancements and exceptions to the GALL report and captured them in the Oyster Creek commitment tracking system
  - In response to NRC identified inconsistencies, the Applicant revised the application or entered the inconsistencies into the corrective action program

Inspection Conclusion

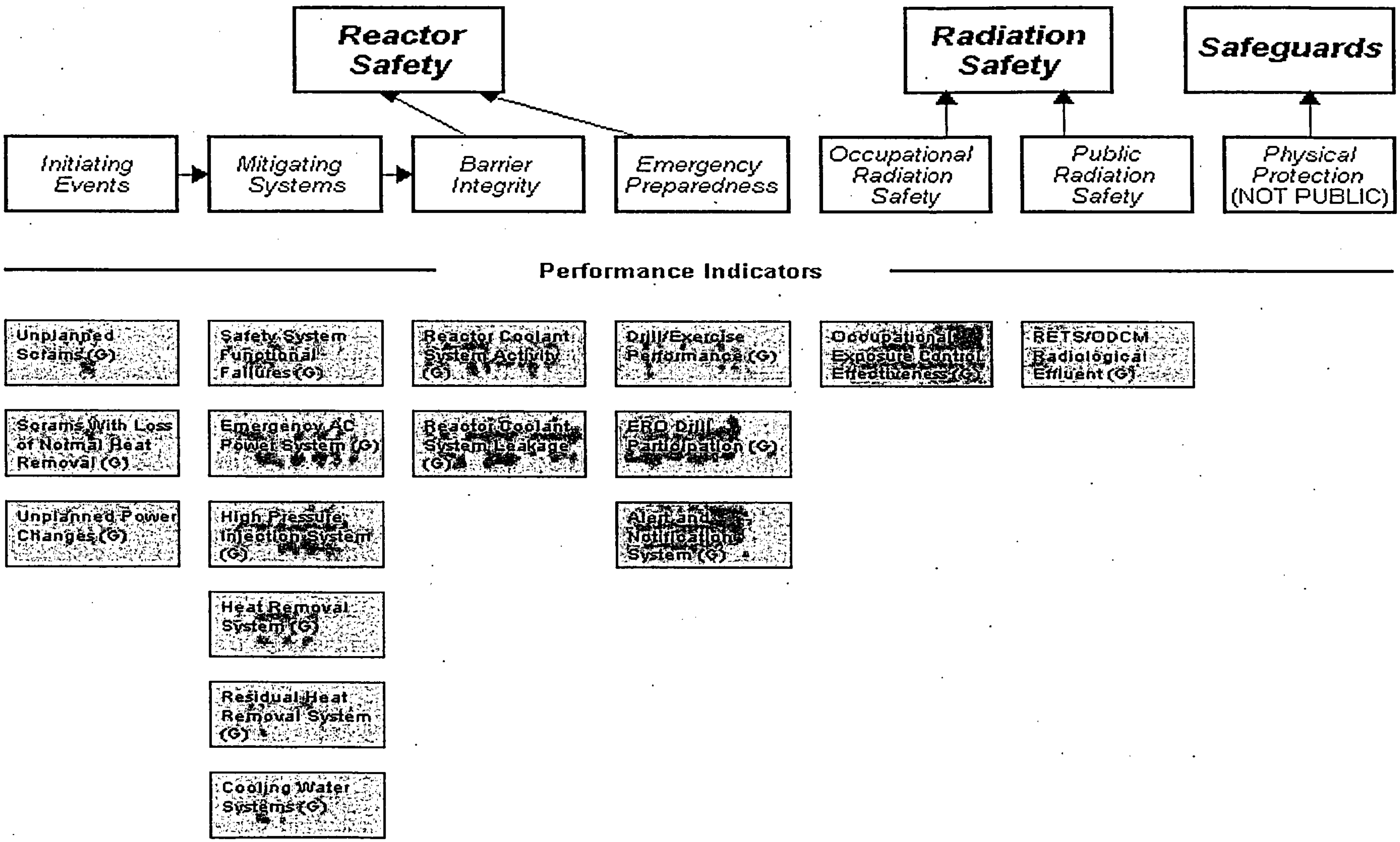
- Overall, the inspection results support a conclusion that the proposed activities will reasonably manage the effects of aging in the systems, structures, and components identified in the application.

- The documentation supporting the application was in an auditable and retrievable form

Current Performance

- Licensee is in the Regulatory Response Column (Column 2) of the NRC's Action Matrix
- The Licensee continues to follow the Revised Reactor Oversight Process
- One cross-cutting issue in the area of human performance (personnel).

Performance Indicators



Last Modified: August 2, 2006

Inspection Findings

Reactor Safety — *Initiating Events* → *Mitigating Systems* → *Barrier Integrity*; *Emergency Preparedness*

Radiation Safety — *Occupational Radiation Safety*; *Public Radiation Safety*

Safeguards — *Physical Protection (NOT PUBLIC)*

Most Significant Inspection Findings

	Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Physical Protection (NOT PUBLIC)
2Q/2006	G	G	G	No findings this quarter	No findings this quarter	G	
1Q/2006	G	G	No findings this quarter	No findings this quarter	G	G	
4Q/2005	No findings this quarter	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	
3Q/2005	G	No findings this quarter	G	W (1)	No findings this quarter	No findings this quarter	

Miscellaneous findings

Additional Inspection & Assessment Information

- Assessment Reports/Inspection Plans:
  - 2Q/2006
  - 1Q/2006
  - 4Q/2005
  - 3Q/2005
- Cross Reference Of Assessment Reports
- List of Inspection Reports
- List of Assessment Letters/Inspection Plans
- Baseline Inspection Completion Information

Last Modified: August 2, 2006

Section 3: Aging Management Programs (AMPs)

- 57 AMPs
  - 36 existing AMPs
  - 21 new AMPs (includes11 new AMPs for the FRCT)
- GALL Consistency
  - 12 Consistent with GALL Report amp
  - 38 Consistent with GALL exceptions/enhancements amp
  - 7 Plant Specific amp

Section 3 – Aging Management Example

- Protective Coating Monitoring and Maintenance Program
  - Existing plant program - Consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program"
  - Credited for Drywell and Torus aging management
  - The inspection of 100% of the sandbed region epoxy coating before the PEO and every 10 years during the period of extended operation.
    - Inspections will be staggered such that at least three bays will be examined every other refueling outage.
  - The inspection of all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the current coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will meet the requirements of ASME Section XI, Subsection IWE.

Section 3 – Aging Management Example

- Structures Monitoring Program
  - Existing program credited
  - 17 Commitments identified
  - The program includes elements of the Masonry Wall Program and the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program.
  - This program also includes structures for Station Blackout system, phase bus enclosure assemblies, and fire protection Communication System structures (Met-Tower)

Section 3 – Aging Management Example

- Periodic Monitoring of Combustion Turbine Power Plant - Station Blackout – FRCT
  - 10 Commitments to implement the Aging Management programs.

c

Section 3: Aging Management Review Overview

3.1	Reactor Vessel, Internals and Coolant System	6 systems
3.2	Engineered Safety Features	3 systems
3.3	Auxiliary Systems	41 systems
3.4	Steam and Power Conversion Systems	7 systems
3.5	Containments, Structures, and Component Supports	19 structures
3.6	Electrical and I&C Components	8 groups
3.7	Station Blackout System (Forked River Combustion Turbines), Radio Communications System, and Meteorological Tower (Met Tower was added to scope)	

Aging Management – Drywell Shell

- Three Aging Management Programs
  - ASME Section XI, Subsection IWE
  - Protective Coating Monitoring and Maintenance Program
  - 10 CFR 50 Appendix J Programs

- UT of sand-pocket region performed in 1992 and 1994 determined that corrosion rates had been arrested.

- Water leakage monitoring program (each refueling)
  - refueling seal
  - drywell air gap drains
  - sand pocket drains

- 11 Commitments for Drywell

Com OIs

Section 3 – Aging Management of In-Scope Inaccessible Concrete

	Acceptance Criteria	OCGS
pH	>5.5	5.6 – 6.4*
Chlorides	<500 ppm	3 - 138
Sulfates	<1500 ppm	7 - 73

- * Below-grade environment is non-aggressive except for fresh water pump-house
- Periodic testing of ground water will be performed for Structures Monitoring Program

Section 4 Time-Limited Aging Analyses (TLAA)

- 4.1 TLAA Process
- 4.2 Neutron Embrittlement of the RPV and Internals
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Loss of Prestress in Concrete Containment Tendons (N/A)
- 4.6 Fatigue Analysis of Primary Containment
- 4.7 Plant Specific TLAAs
  - 4.7.1 Crane Load Cycle Limit
  - 4.7.2 Drywell Corrosion
  - 4.7.3 Equipment Pool/Reactor Cavity Wall Rebar Corrosion
  - 4.7.4 Reactor Vessel Weld Flaw Evaluations
  - 4.7.5 CRD Stub Tube Flaw Analysis

Section 4.2 Neutron Embrittlement

Reactor Vessel Upper Shelf Energy (USE) – Analysis Summary

OCGS Reactor Vessel Material	Percent USE Reduction of OCGS Reactor Vessel Material	Percent USE Reduction Acceptance Criterion*	Evaluation Result
Limiting Plate 564-03D, E, F	29%	USE drop must be < 29.5%	Acceptable pursuant to 10 CFR 54.21(c)(1)(ii)
Limiting Weld 86054B & 1248	32%	USE drop must be < 39%	Acceptable pursuant to 10 CFR 54.21(c)(1)(ii)

*acceptance criteria established per BWRVIP-74.

Section 4.2.4 Reactor Vessel Circumferential Weld Examination Relief

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

RV Material	TLAA Basis	Acceptance Criterion (°F)	OCGS Value (°F)
Limiting Circ. Weld	BWRVIP-05 Mean RT_{NDT} Value (°F)	<128.5	9.8
Limiting Axial Weld	BWRVIP-05 Mean RT_{NDT} Value (°F)	<114	50.3

- TLAAs for the Circ. Weld and Axial Weld Mean RT_{NDT} values were acceptable pursuant to 10 CFR 54.21(c)(1)(ii)

Section 4.3: Metal Fatigue

- Cumulative Usage Factor is projected to be less than ASME Code limit of 1.0 for components based on a 60-year life.

- Monitored by the Fatigue Monitoring Program

- Staff accepted the evaluations

Section 4.4 Environmental Qualification (EQ) of Electrical Equipment

- Applicant's EQ Program consistent with GALL AMP X.E1, "Environmental Qualification of Electrical Equipment"

- Staff concluded the EQ Program is adequate to manage the effects of aging on the intended function of electrical components

Section 4.6 Fatigue Analysis of Primary Containment

- Staff accepted the evaluations in accordance with 10 CFR 54.21(c)(1)(i)

Section 4.7.5 CRD Stub Tube Flaw Analysis

- Staff accepted the evaluations in accordance with 10 CFR 54.21(c)(1)(i)

TLAA Summary

- 10 CFR 54.3 - TLAA is list adequate
- 10 CFR 54.21(c)(2) – no plant-specific exemptions

Section 4.7.2 Drywell Corrosion

- On the basis of its review, the staff concludes that, pending resolution of OIs 4.7.2-1.1, 4.7.2-1.2, 4.7.2-1.3, 4.7.2-1.4, and 4.7.2-3, the applicant has demonstrated, that for the drywell corrosion TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

Confirmatory Analysis
Oyster Creek Drywell

Hans Ashar

NRR

Sandia

Conclusions

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

OFFICE OF NUCLEAR REACTOR REGULATION

UNITED STATES NUCLEAR REGULATORY COMMISSION

5 open items:

- **<u>OI 4.7.2-1.1:</u>** Drywell Corrosion Sampling in the transition area. Question on the appropriate number of locations on the drywell for periodic ultrasonic testing
- **<u>OI 4.7.2-3:</u>** Questions about the implementation of the Protective Coating Monitoring and Maintenance Program. The extent of inspections of epoxy-coated drywell surfaces

- **<u>OI 4.7.2-1.2:</u>** Drywell Corrosion Inaccessible areas embedded concrete. the possibility of corrosion of drywell liner plates embedded in concrete between the containment floor and foundation

- **<u>OI 4.7.2-1.3:</u>** Buckling Analysis. the appropriateness of certain technical assumptions in AmerGen's analysis of the potential for "buckling," of the drywell shell
- **<u>OI 4.7.2-1.4:</u>** Drywell Shell Thickness and the Minimum Available Thickness Margin. The use of an ASME Code provision to simulate the behavior in thinned areas

Go to 3.5 Go to 4.7.2

BACK

License Conditions:

- The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed license.
- The second license condition requires future activities identified in the UFSAR supplement to be completed prior to the period of extended operation.
- The third license condition requires all surveillance capsules placed in storage to be maintained for future insertion. Any changes to storage requirements must be approved by the staff as required by 10 CFR Part 50, Appendix H.

BACK

FRCT New AMPs and Commitments

Bolting Integrity	B.1.12A
Closed Cycle Cooling Water System	B.1.14A
Above Ground Steel Tanks	B.1.21A
Fuel Oil Chemistry	B.1.22A
One Time Inspection	B.1.24A
Selective Leaching of Materials	B.1.25A
Buried Piping Inspection	B.1.26A
Periodic Monitoring of FRCT – Electrical	B.1.37
Inspection of Piping and Ducts	B.1.38A
Lubricating Oil Analysis Program	B.1.39A
Periodic Inspection	B.2.5A

TLAA Criteria

- *Time-limited aging analyses*, for the purposes of this part, are those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal;

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

BACK

Scoping and Screening Systems

- **Reactor Vessel, Internals, and Reactor Coolant System (8)**
  - Control Rods
  - Nuclear Boiler Instrumentation
  - Reactor Pressure Vessel
  - Fuel Assemblies
  - Reactor Head Cooling System
  - Reactor Recirculation System
  - Isolation Condenser System
  - Reactor Internals
- **Engineered Safety Features Systems(4)**
  - Automatic Depressurization System
  - Standby Gas Treatment System (SGTS)
  - Containment Spray System
  - Core Spray System
- **Auxiliary Systems (41)**
  - "C" Battery Room Heating & Ventilation
  - 4160V Switchgear Room Ventilation
  - 480V Switchgear Room Ventilation
  - Battery and MG Set Room Ventilation
  - Chlorination System
  - Circulating Water System
  - Containment Inerting System
  - Containment Vacuum Breakers
  - Control Rod Drive System
  - Control Room HVAC
  - Cranes and Hoists
  - Drywell Floor and Equipment Drains
  - Emergency Diesel Generator & Aux Sys
  - Emergency Service Water System
  - Fire Protection System
  - Fuel Storage and Handling Equipment
  - Hardened Vent System
  - Heating & Process Steam System
  - Hydrogen & Oxygen Monitoring System
  - Instrument (Control) Air System
  - Main Fuel Oil Storage & Transfer sys
  - Misc.Floor and Equipment Drain System
  - Nitrogen Supply System
  - Noble Metals Monitoring System
  - Post-Accident Sampling System
  - Process Sampling System
  - Radiation Monitoring System
  - Radwaste Area Heat&Vent System
  - Reactor Building CCWater System
  - Reactor Building Floor and Equipment Drains
  - Reactor Building Ventilation System
  - Reactor Water Cleanup System
  - Roof Drains and Overboard Discharge
  - Sanitary Waste System
  - Service Water System
  - Shutdown Cooling System
  - Spent Fuel Pool Cooling System
  - Standby Liquid Control System (Liquid Poison System)
  - Traveling In-Core Probe System
  - Turbine Building CCW System
  - Water Treatment & Distribution System
- **Steam and Power Conversion Systems (7)**
  - Condensate System
  - Condensate Transfer System
  - Feedwater System
  - Main Condenser
  - Main Generator and Auxiliary System
  - Main Steam System
  - Main Turbine and Auxiliary System

Structures in Scope

- **Structures**
  - Primary Containment
  - Condensate Transfer Building
  - Emerg Diesel Generator Building
  - Fire Pumphouses
  - Intake Structure and Canal (Ultimate Heat Sink)
  - New Radwaste Building
  - Turbine Building

  Reactor Building
  Dilution Structure
  Exhaust Tunnel
  Heating Boiler House
  Miscellaneous Yard Structures
  Office Building
  Ventilation Stack

  Chlorination Facility
  Fire Pond Dam
  Oyster Creek Substation

- **Component Supports Commodity Group**
  - In its responses dated October 12, November 11, and December 9, 2005, and May 18 and June 7, 2006, the applicant stated that it had determined that the repeater located at the Meteorological Tower (Met Tower) is credited for communication capabilities for some 10 CFR Part 50, Appendix R, scenarios. Therefore, the repeater and associated support equipment, including the backup gas (propane) engine generator located at the Met Tower, are now within the scope of license renewal and subject to an AMR.

- **Electrical Systems and Electrical Commodity Group**
  - Credit for STATION BLACKOUT EQUIPMENT
  - In LRA Table 2.5.1.19, the ACC combustion turbines are identified as one combustion turbine power plant unit within the scope of license renewal and subject to an AMR. As described in SER Section 2.5.5.2, in its response to RAI 2.5.1.19-1, the applicant stated that it had revised the combustion turbine power plant unit scoping and screening methodology. Mechanical, electrical, and structural component types were itemized in detail consistent with scoping and screening methodology for other the other license renewal systems and structures.

Consistent with GALL 12 out of 57

- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.1.10) – New
- Flow-Accelerated Corrosion (B.1.11)
- Compressed Air Monitoring (B.1.17)
- One-Time Inspection (B.1.24) - New
- Selective Leaching of Materials (B.1.25) – New
- 10 CFR Part 50, Appendix J (B.1.29)
- Masonry Wall Program (B.1.30)
- Protective Coating Monitoring and Maintenance Program (B.1.33)
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.34) – New
- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36) - New
- Environmental Qualification (EQ) Program (B.3.2)
- Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.40) - New

Consistent With Exceptions/Enhancements

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)
- Reactor Head Closure Studs (B.1.3)
- BWR Vessel ID Attachment Welds (B.1.4)
- BWR Feedwater Nozzle (B.1.5)
- BWR Control Rod Drive Return Line Nozzle (B.1.6)
- BWR Stress Corrosion Cracking (B.1.7)
- BWR Penetrations (B.1.8)
- BWR Vessel Internals (B.1.9)
- Bolting Integrity (B.1.12)
- Open-Cycle Cooling Water System (B.1.13)
- Closed-cycle Cooling Water System (B.1.14)
- Boraflex Rack Management Program (B.1.15)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)
- BWR Reactor Water Cleanup System (B.1.18)
- Fire Protection (B.1.19)
- Fire Water System (B.1.20)
- Above Ground Outdoor Tanks (B1.21)
- Fuel Oil Chemistry (B1.22)
- Reactor Vessel Surveillance (B.1.23)
- One Time Inspection (B1.24)
- Selective Leaching of Materials(B1.25)
- Buried Piping Inspection (B.1.26)
- Buried Piping and Tank Inspection (MetTower B1.26B)
- ASME Section XI, Subsection IWE (B.1.27)
- ASME Section XI, Subsection IWF (B.1.28)
- Structures Monitoring Program (B.1.31)
- Inspection of Water-Control Structures (B.1.32)
- Electrical Cables and Connections Not Subject to E.Q. Used in Instrument Circuits (B.1.35)
- Metal Fatigue of Reactor Coolant Pressure Boundary (B.3.1)

- Bolting Integrity - FRCT (B.1.12A) - New
- Aboveground Steel Tanks - FRCT (B.1.21A) - New
- Closed-cycle Cooling Water System - FRCT (B.1.14A) - New
- Fuel Oil Chemistry - FRCT (B.1.22A) - New
- One-Time Inspection - FRCT (B.1.24A) - New
- Buried Piping Inspection - FRCT (B.1.26A) - New
- Selective Leaching of Materials - FRCT (B.1.25A) – New
- Periodic Monitoring of Combustion Turbine –FRCT(B.1.37A)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT (B.1.38A) - New
- Lubricating Oil Analysis Program - FRCT (B.1.39) - New
- Buried Piping and Tank Inspection-Met Tower Repeater Engine Fuel Supply (B.1.26B) - New

Plant-Specific (7 out of 57)

- Periodic Testing of Containment Spray Nozzles (B.2.1)
- Lubricating Oil Monitoring Activities (B.2.2)
- Generator Stator Water Chemistry Activities (B.2.3)
- Periodic Inspection of Ventilation Systems (B.2.4)
- Periodic Inspection Program (B.2.5) – New
- Wooden Utility Pole Program (B.2.6) - New
- Periodic Inspection Program - FRCT (B.2.7) - New

Drywell Commitments

- Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed once prior to the PEO another four years later and then a frequency of every 10 years

- Consistent with current practice, a strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

- The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.
  - The sand bed region drains will be monitored daily during refueling outages.

- Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once.

Drywell Commitments

- Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once.

- A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact.

- Conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

- During the next UT inspections to be performed on the drywell sand bed region, an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell.

Drywell Commitments

- Conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell.

- Conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate.

- When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.

- The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle

BACK

Sandia Analysis Modeling Assumptions

Model Geometry

- 360 model of drywell and vent lines
- Torus not modeled
- Equipment Hatch and 10 vent lines are modeled

mod1

General loads

- Model includes gravity and dead loads
- Other dead loads were taken from previous GE analysis
- Seismic loads included with static coefficients from FSAR

Controlling Load Cases

- Refueling
- Design Basis Accident with Earthquake
- Post Accident Flooding with Earthquake

Modeling Corrosion

mod2

- Cylinder, upper sphere, and middle sphere assigned uniform thicknesses
- Thickness is based on extrapolated UT measurements
- Lower sphere assumed 10 regions
- Each region assigned thickness based on average of UT data points

Sandia Analysis Preliminary Results

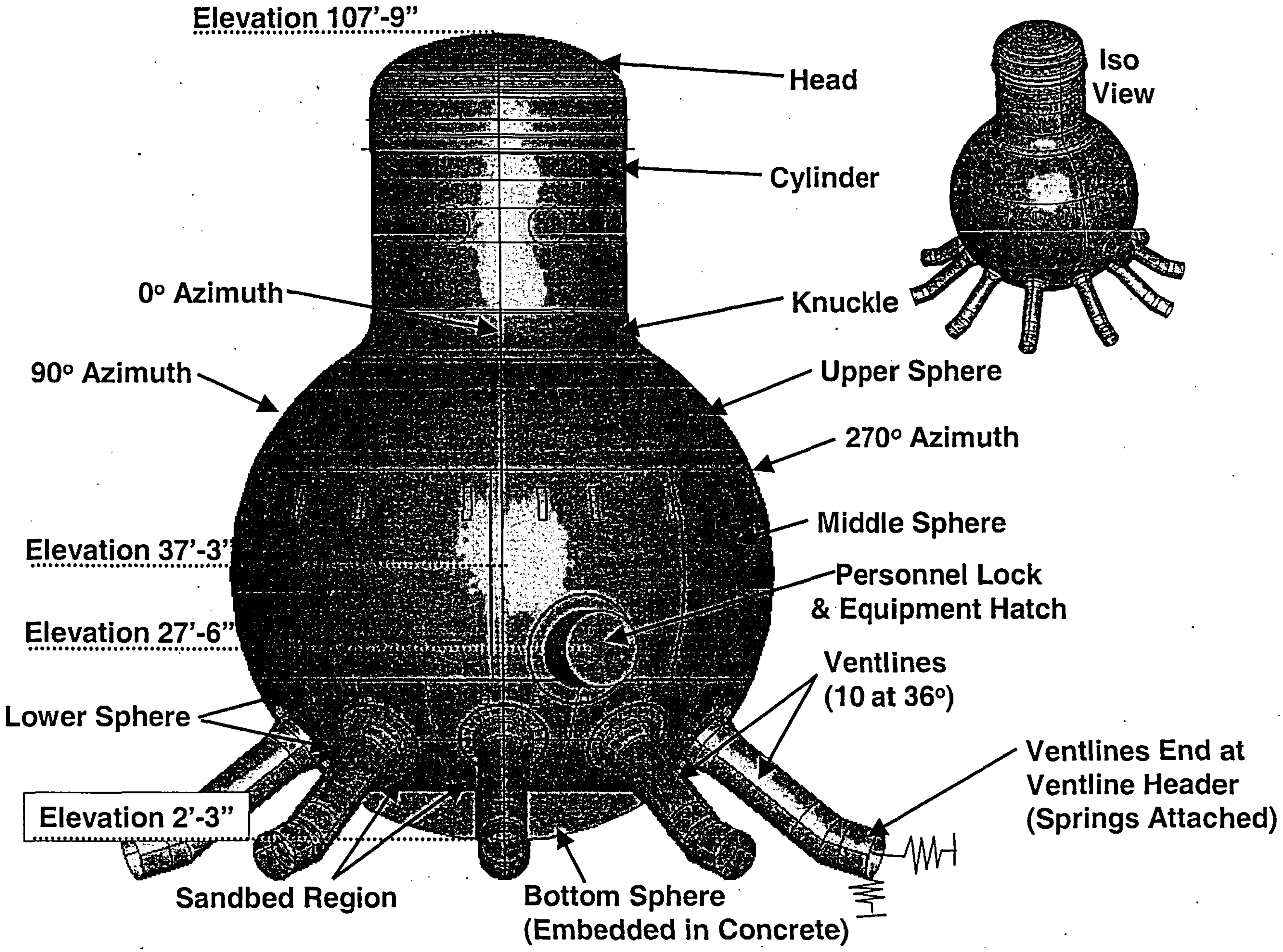
- **Refueling Load Combination (dead + live + seismic+ refueling loads)**
  - All stresses within ASME Service Level B requirements
  - Sandbed buckling (factor of safety of 2.00 required in ASME – 284)
    - With no degradation SF=3.85
    - With degradation SF=2.15

- **Accident Load (dead + internal pressure + thermal + seismic loads)**
  - All stresses within ASME Service Level C requirements
  - Buckling is not controlling

- **Post-Accident Load Case**
  - All stresses within ASME Service Level D requirements
  - Sandbed buckling (factor of safety of 1.67 required in ASME – 284)
    - With no degradation SF=3.65
    - With degradation SF=2.74

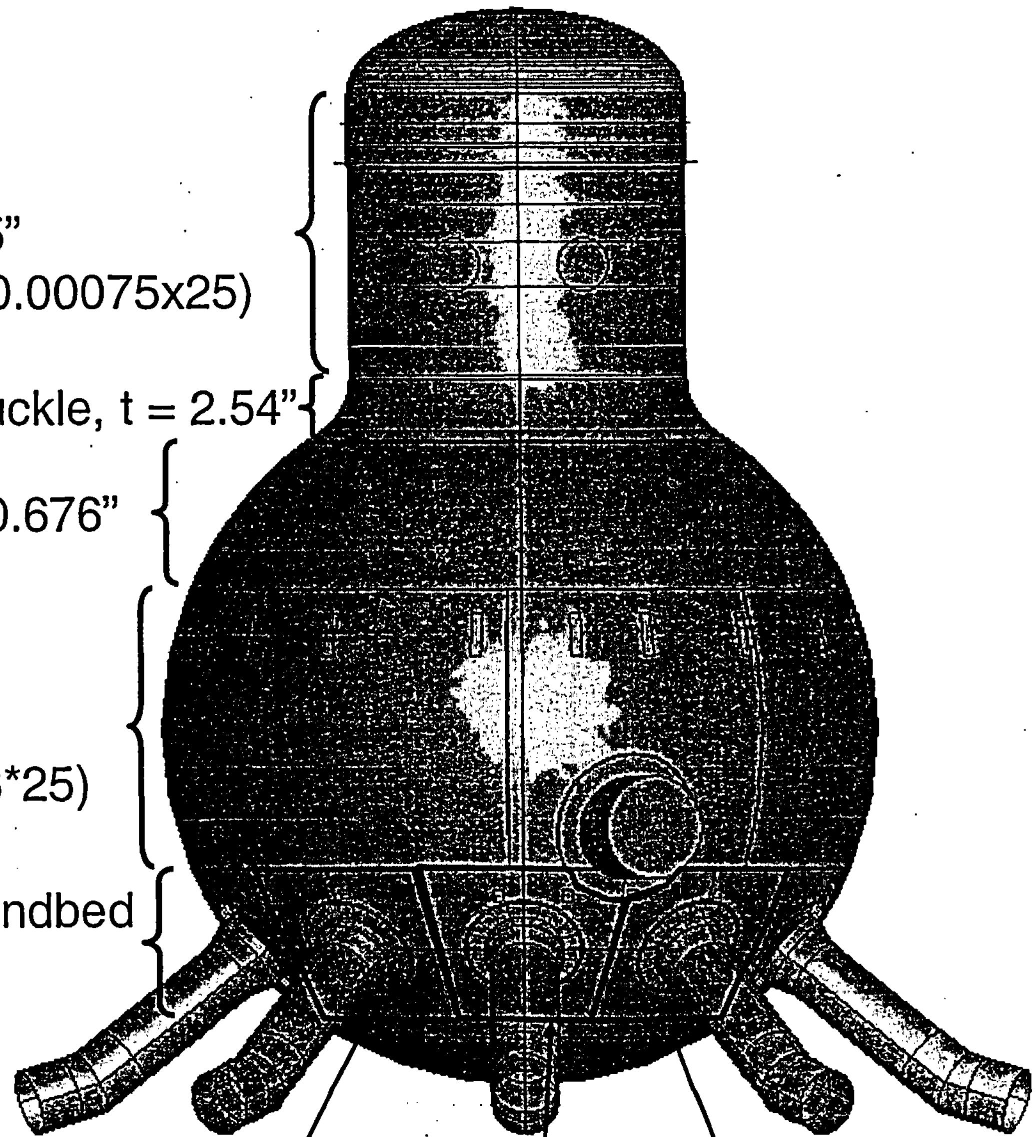
BACK

Oyster Creek Drywell Model

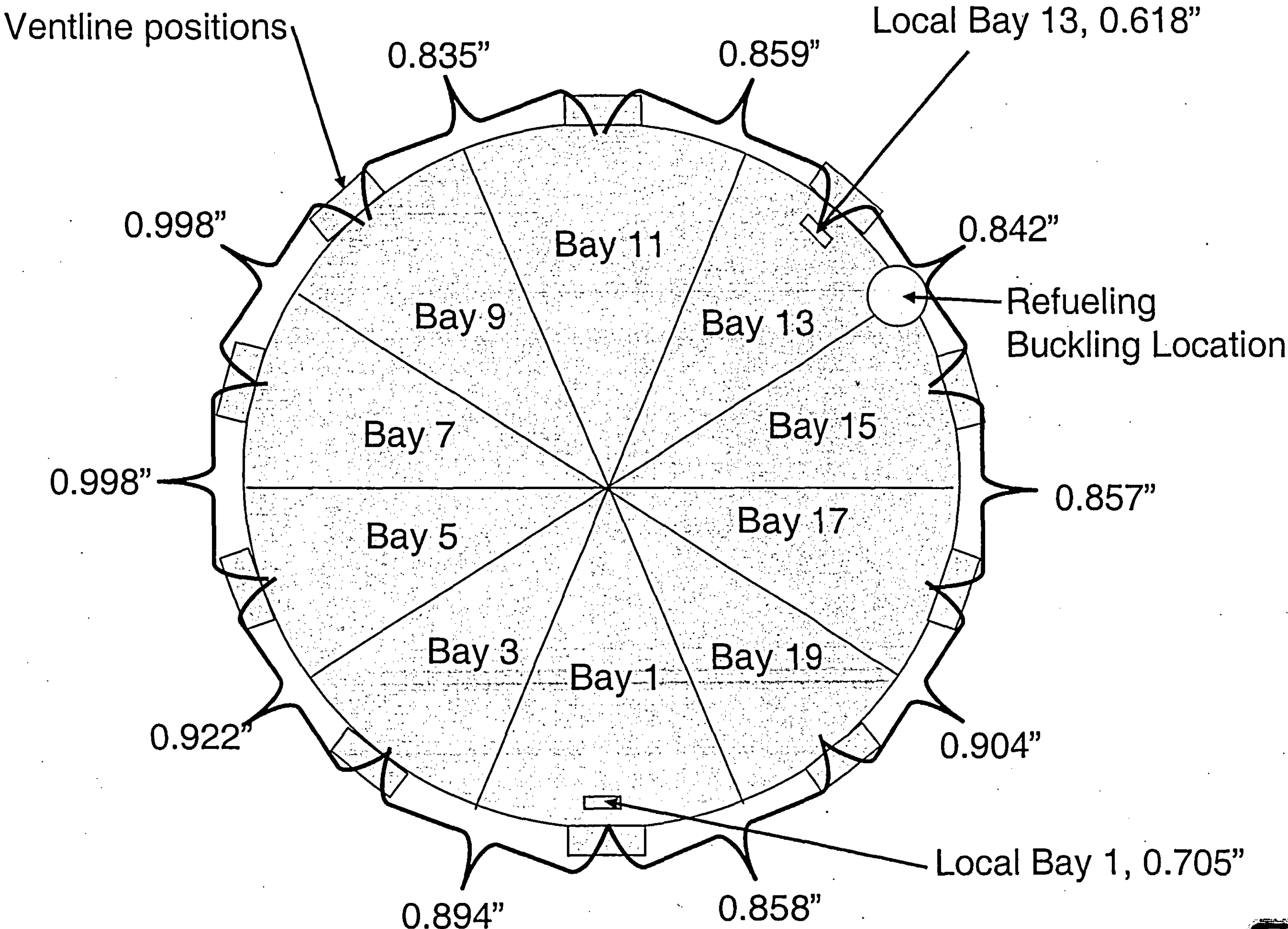


BACK

Oyster Creek Drywell Model – Assumed Thickness



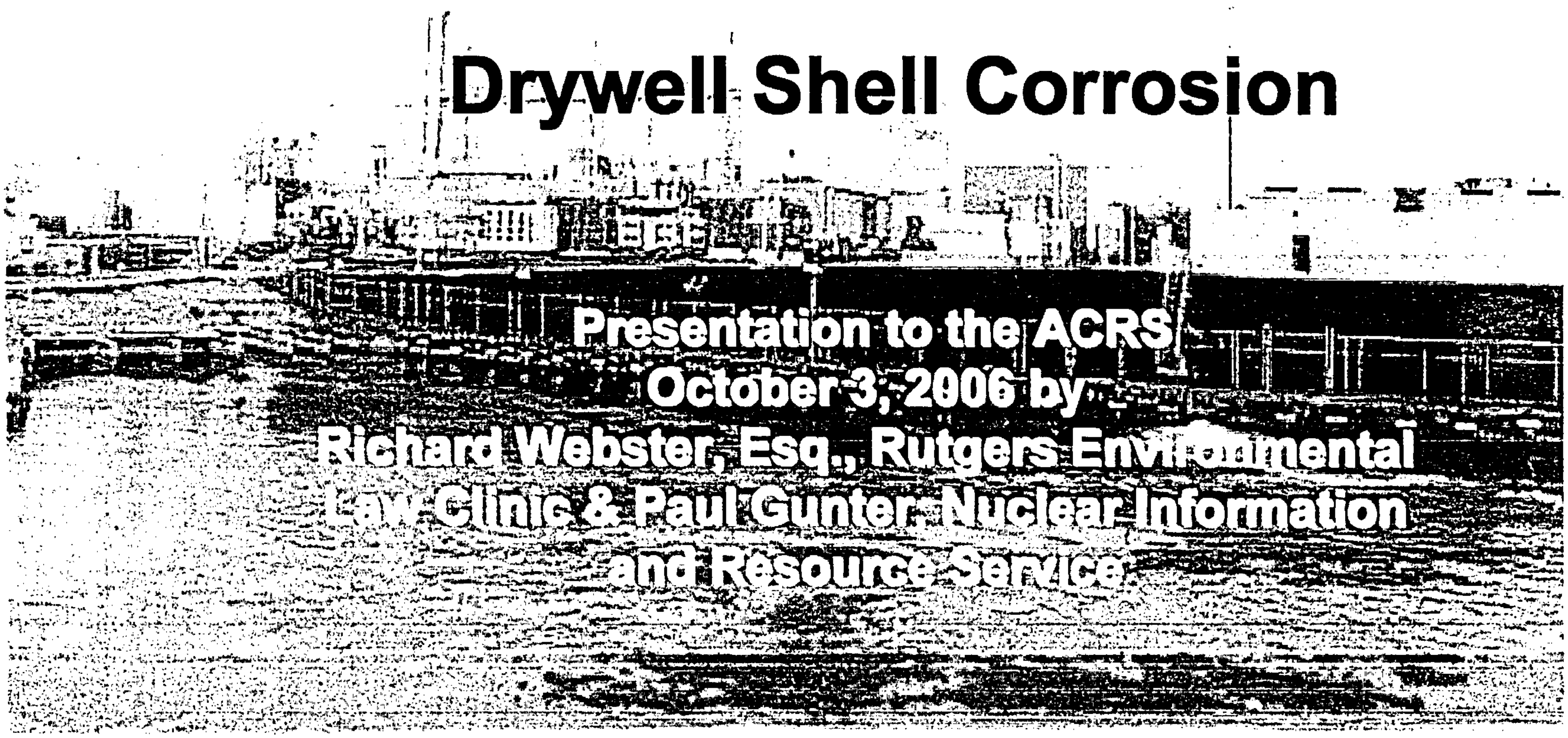
Estimated Thicknesses in the Lower Sphere



BACK

Oyster Creek Nuclear Generating Station License Extension:

Drywell Shell Corrosion



Presentation to the ACRS
October 3, 2006 by
Richard Webster, Esq., Rutgers Environmental
Law Clinic & Paul Gunter, Nuclear Information
and Resource Service

Oyster Creek
Containment Corrosion

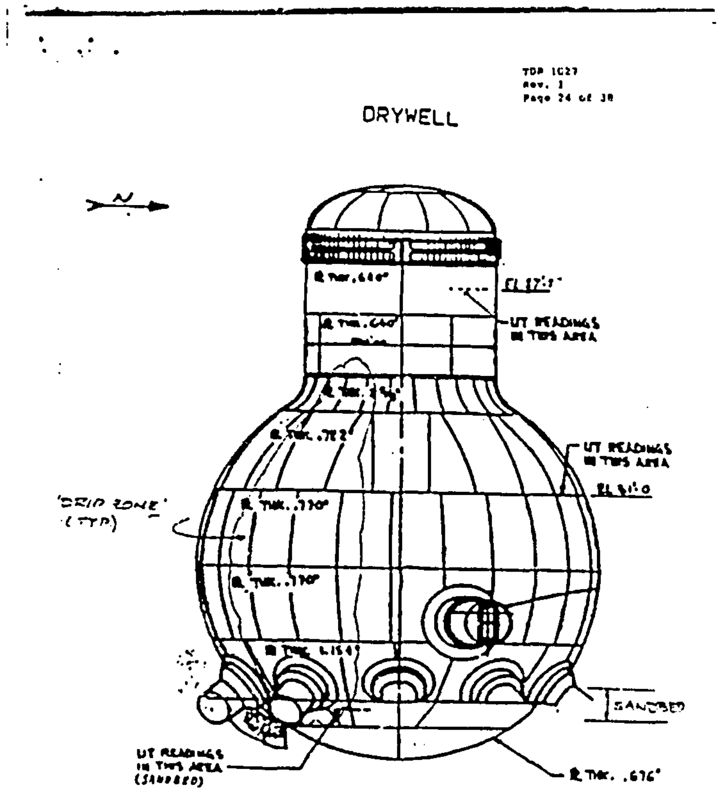
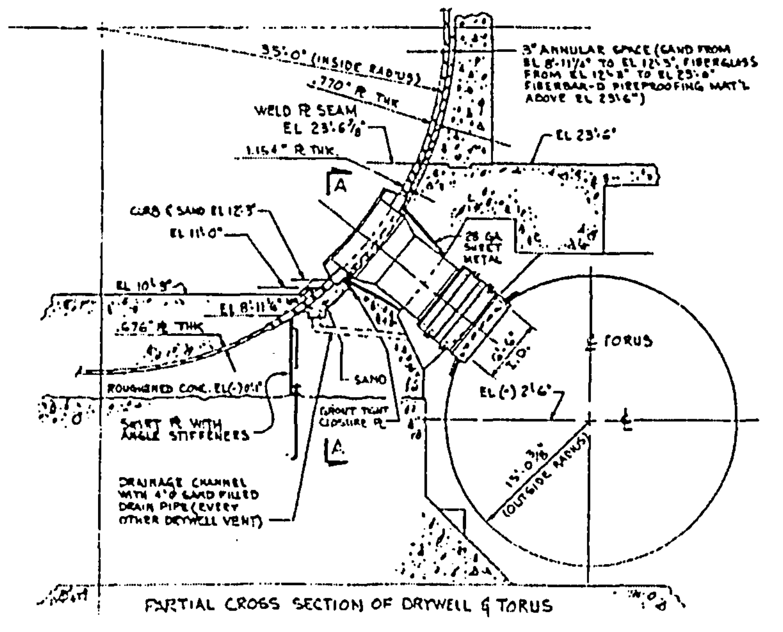


FIG. 2
ILLUSTRATION OF DRYWELL STRATA



Oyster Creek
Containment Corrosion

SUMMARY OF 14R OUTAGE UT THICKNESS MEASUREMENTS

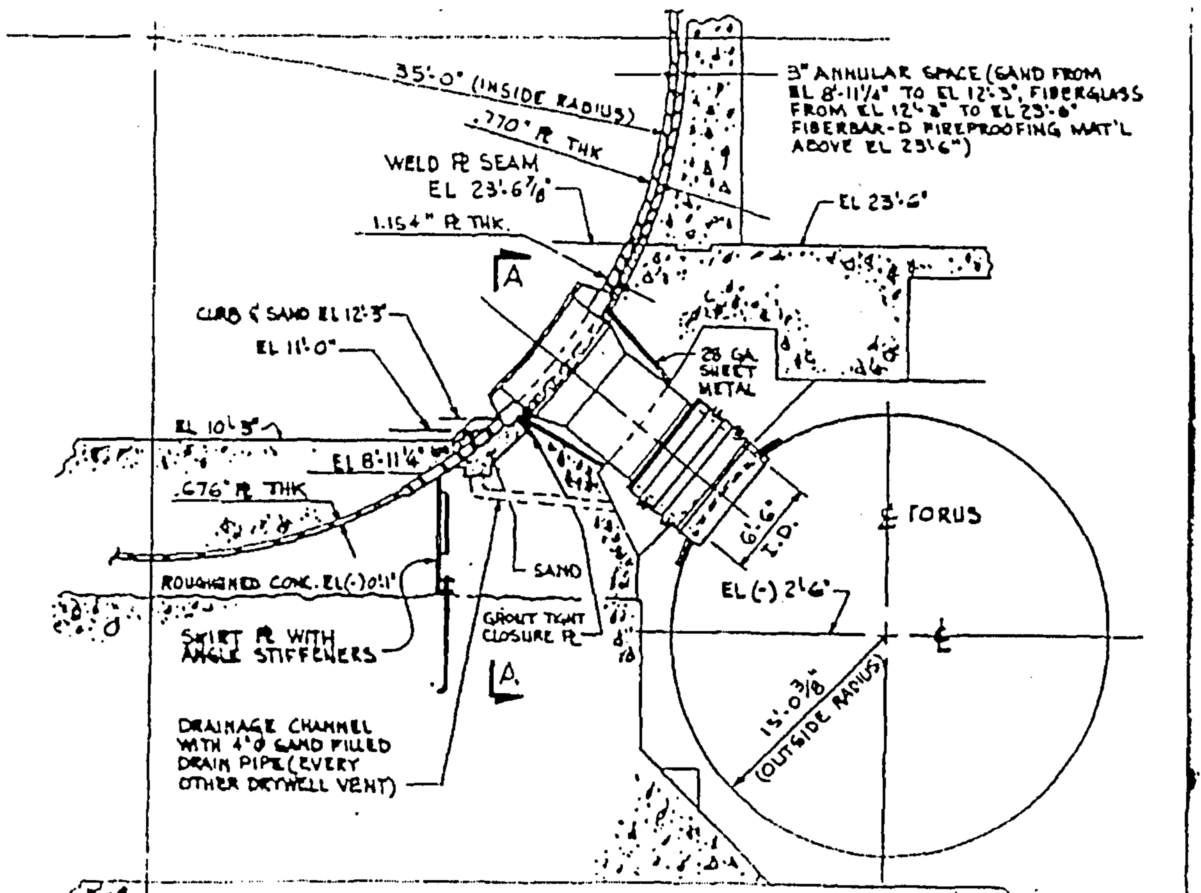
(TAKEN FROM INSIDE DRYWELL)

	Vessel Thickness (inches)			
Drywell Region	As Designed (inches)	Minimum Required at 1.1 Smc (inches)	Current Thinnest (12/92) (inches)	Previous Thinnest (7/91) (inches)
Cylinder	0.640	0.580	0.614	0.612
Upper Sphere (El. 51' to 65')	0.722	0.650	0.691	0.695
Middle Sphere (El. 23' to 51')	0.770	0.670	0.743	0.745
Sand Bed	1.154	0.736	0.800	0.803

Identified Concerns

- Possible corrosion in the embedded region
  - concern covers both current safety and potential for future undetected degradation
- Sandbed region
  - whether the drywell liner meets safety margins now; and, if so
  - whether any significant degradation in the future would be detected before safety margins are violated – subject of contention

Oyster Creek Containment Corrosion



PARTIAL CROSS SECTION OF DRYWELL & TORUS

Embedded Region in 1992

- When sand was removed in 1992 the sand bed floor was unfinished, water had ponded on the floor, and the floor had deep craters, probably due to corrosion of rebar
- Until 1992 no seal was present between the shell and the concrete to reduce penetration of water into gaps
- Moisture from groundwater has not been ruled out

Corrosion Possible

- Conditions in the embedded region from the early 60s through to 1992 were favorable for crevice corrosion, which could then self-accelerate
- Since 1992, it has been assumed, but not verified that the elastomer seal has kept the embedded region dry
- Assumption of dry conditions since 1992 not valid because seal could be leaking and water could be coming from below

Effect of Sand Removal

- Removal of sand could have accelerated corrosion in the embedded region because of differential aeration, if wet conditions persisted
- Corrosion rates in the sandbed region do not bound corrosion rates in the embedded region
- Steel thickness in the lower embedded region was nominally 0.676 inches and corrosion rates could be up to 0.33 inches per year

Necessary Actions

- Comprehensively check current thickness of metal in the embedded region
- Monitor for wet conditions in the embedded region using electronic detectors
- If water is present, must sample and trace source
- Need to establish acceptance criteria and an adequate aging management program, need objective data where experts disagree

Sandbed Established Safety-based Acceptance Criteria

- Most critical constraint is buckling
- Uniform criterion - 0.736" wall thickness
- Single point criterion - no point should be less than 0.49 inches
- Small area criterion - one square foot per bay may be less than 0.736 inches, but must be greater than 0.536 inches
- All based on modeling of 36 degree slices of shell that inherently assumed axial symmetry and spherical shape.

Problems With Established Criteria

- Sandbed is far from uniform, some bays were much more corroded than others with a dimpled "golf ball" surface
- Symmetry assumption prevented model simulating anti-symmetric buckling
- Assumption of spherical shape not justified – shell was welded together in situ in the 1960s, could be far from spherical
- Derivation of the small area criterion was not rigorous – did not see if shapes other than a square could be more critical – e.g. horizontal gash

Measured Shell Thickness

- Last UT measurements taken with procedures that are not in question were carried out in 1992
- Results taken from both inside and outside
- Smallest measured result was 0.603 inches from inside and 0.618 inches from the outside
- Area that is less than 0.736 inches recently estimated at 0.68 ft. sq., but no account taken of uncertainty or failure to measure all thin areas
- Each measurement is uncertain by 0.03 inches. AmerGen accepted results that showed up to 0.05 inches increase in thickness

AmerGen Accepted "Anomalous" UT Measurements

- May 3, 2006, Dr. Rudolf Hausler:
  The AMGT (average minimal general thickness) for each grid decreases from 1992 to 1994, but then *increases* in 1996. "This is of course physically impossible; metal simply does not spontaneously get thicker."
- Hausler, "I interpret this as a systematic error in the UT methodology employed."
- June 20, 2006, AmerGen admits that 1996 UT results were anomalous. "In at least one case, the increase is as much as 50 mils in a two year period."
- 1994 results not validated – were similar problems with procedures
- AmerGen relied in part on the 1994 and 1996 results to claim corrosion in sandbed was zero

Margins Established in 1992

- Single point margin overestimated at 0.11 inches by operator
- Single point margin estimated by Dr. Hausler at around 0.06 inches
- Small areas margin overestimated at 0.07 inches by operator
- Small areas margin estimated at around 0.03 inches by Dr. Hausler based on possible expansion of area thinner than 0.736 inches

Inadequate Spatial Scope

- Hausler, June 23, 2006 – Much of sandbed is inaccessible from inside:
  - Initial investigations before sand removed measured shell from the inside shell "at lowest accessible locations"
  - Interior concrete floor & curb 2 ft. higher than exterior floor leaving about 2/3 of sandbed region not tested.
  - Interior floor removed in 2 bays & found similar thinning below floor level confirming area should not be omitted from UT
- Both Hausler and Stress believe much more spatially comprehensive UT thickness measurements are needed to accurately represent current state of vessel

Simplistic Treatment of Acceptance

SUMMARY OF 14R OUTAGE UT THICKNESS MEASUREMENTS

(TAKEN FROM INSIDE DRYWELL)

	Vessel Thickness (Inches)			
Drywell Region	As Designed (Inches)	Minimum Required at 1.1 Smc (Inches)	Current Thinnest (12/92) (Inches)	Previous Thinnest (7/91) (Inches)
Cylinder	0.640	0.580	0.614	0.612
Upper Sphere (El. 51' to 65')	0.722	0.650	0.691	0.695
Middle Sphere (El. 23' to 51')	0.770	0.670	0.743	0.745
Sand Bed	1.154	0.736	0.800	0.803

Current Margins Unknown

- Acceptance criteria not updated yet
- Recently discovered that water has been draining from the sandbed over the last eight years
- Visual monitoring of epoxy coat is inadequate to detect small pinholes, coat could mask corrosion, and coat is beyond its anticipated life
- UT measured area was not adaptive to thin areas at edges, not representative, is only 3 sq. ft. out of 300 sq. ft., and misses known areas less than 0.736 inches
- Single UT measurement uncertainty is very close to margins, but operator failed to fully account for uncertainty
- Insufficient data to calculate area below 0.736 inches

Predictions About The Future

- Present situation very poorly defined
- Predictions about the future are therefore highly uncertain
- To determine appropriate monitoring for the future in terms of spatial scope and required accuracy need to know current margin to a high degree of certainty – must use most accurate techniques as proposed by Stress
- To determine monitoring frequency need to adequately monitor conditions, estimate worst-case corrosion rate, and account for uncertainty

Proposed UT Program Is Inadequate

- Spatial scope too small - areas of the shell less than 0.736 inches thick would not be systematically identified and tested
- Statistical techniques used in data analysis are flawed
- Coating integrity not adequately maintained
- Monitoring for water is inadequate
- Initial UT monitoring frequency is too low if corrosive conditions are present
- Must build in fail-safe checks

Inadequate Spatial Scope

Hausler, June 23, 2006:

- **AmerGen proposes to measure the same locations measured in 1992, 1994, 1996**
- **Many areas below 0.736 inches are not proposed to be monitored at all**
- **AmerGen must devise a systematic approach to identify and measure all areas thinner than 0.736 inches**

Proposed Statistical Techniques Are Flawed

- Potential for future corrosion not estimated when no corrosion measured
- Erroneous assumption of linearity over time. Even under constant conditions pit corrosion can accelerate
- Erroneous assumption of unchanged conditions
- Use of 95% confidence interval - no justification for the assumption that failing to detect violation of safety margins 1 in 20 times is adequate – must do analysis of safety significance
- Erroneous use of normal statistics and data filtering
- Failed to look systematically at uncertainties in measurements
- Unable to estimate worst-case corrosion rate due to lack of data

Maintaining Coating Integrity

- Visual examination may miss small holidays and pinholes
- Visual examination must be augmented by industry standard objective measurements
- When wet conditions prevail, monitoring frequency must increase to at least quarterly until more certainty prevails
- Response to coating failure must be complete renewal of coating and comprehensive UT measurements within one quarter

Monitoring For Water Is Inadequate

- Recent announcement that operator failed to monitor sandbed drains for 8 years and then dumped collected water without testing dramatically illustrates problems with a purely visual approach
- Now no way of knowing when the leakage occurred, exactly which areas of the shell were wet, or where the water came from
- Having moisture monitored electronically provides verifiable records that show moisture variation in space and time
- Detection of water must trigger comprehensive checks of coating integrity within a quarter

UT Monitoring Frequency

- Cannot decide on UT monitoring frequency until safety margins and worst case corrosion rates are known
- Must make conservative assumptions, and assume other programs are missing something
- Recent experience shows that we cannot rely only on committed inspections alone to drive UT monitoring. Must have fail safe intervals.

Second Possible Failure Mechanism

Hausler, June 23, 2006 points out:

- Chloride induced fatigue cracking is possible
- It will be necessary to examine both the corroded areas and susceptible areas for the existence of stress corrosion cracks in the drywell liner
- Nothing yet proposed to resolve this issue

Conclusions

- Not even a current reasonable assurance of safety
- Know that the proposed monitoring program is inadequate
- More measurements are currently scheduled this month. If they were comprehensive, many of the current safety questions could be answered
- At best, conclusions about future safety of the shell in the SER and the inspection report were premature
- Need to discard all the invalid assumptions that have accumulated and conduct an analysis that is as rigorous and quantitative as possible based on comprehensive data and careful consideration of uncertainty

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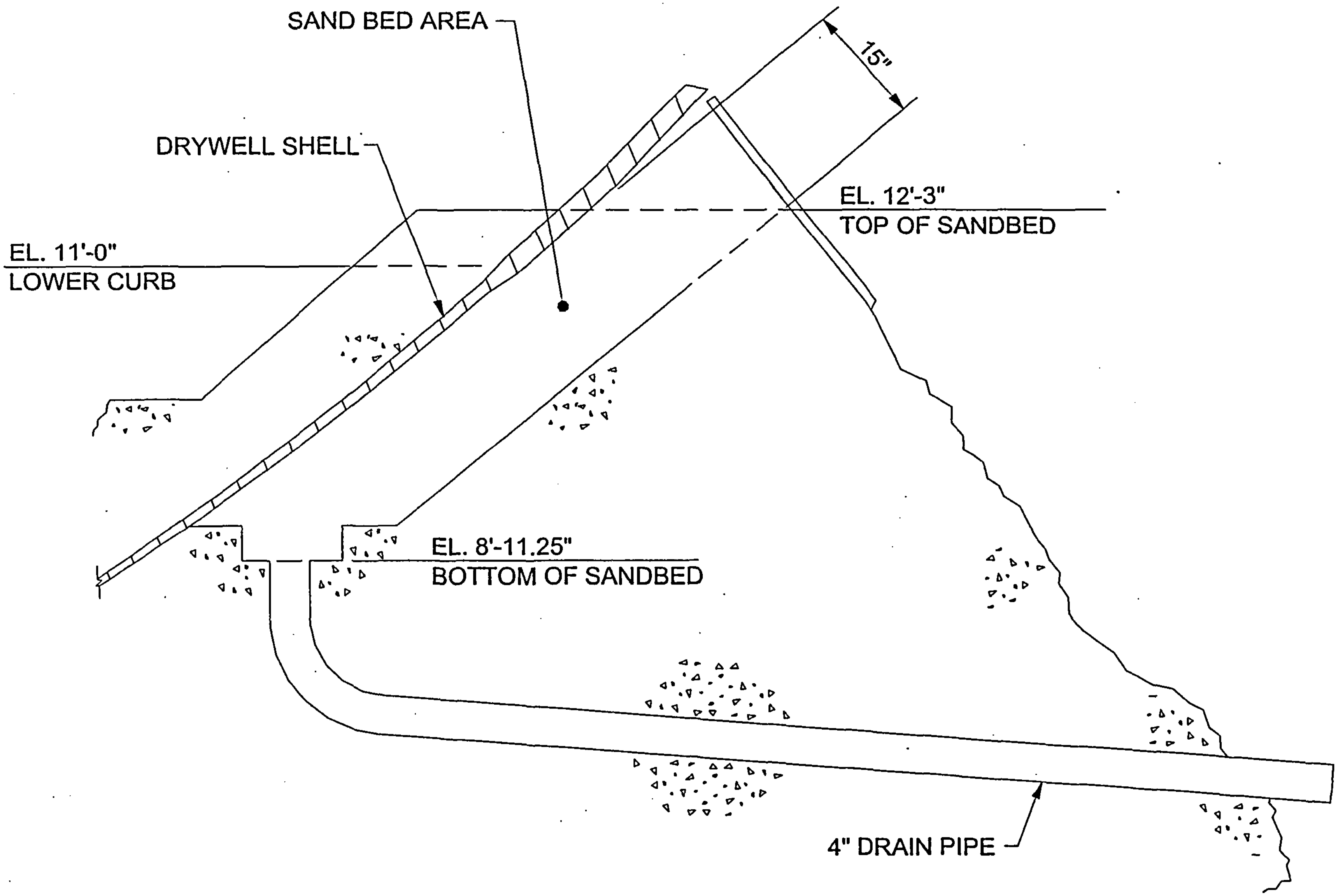
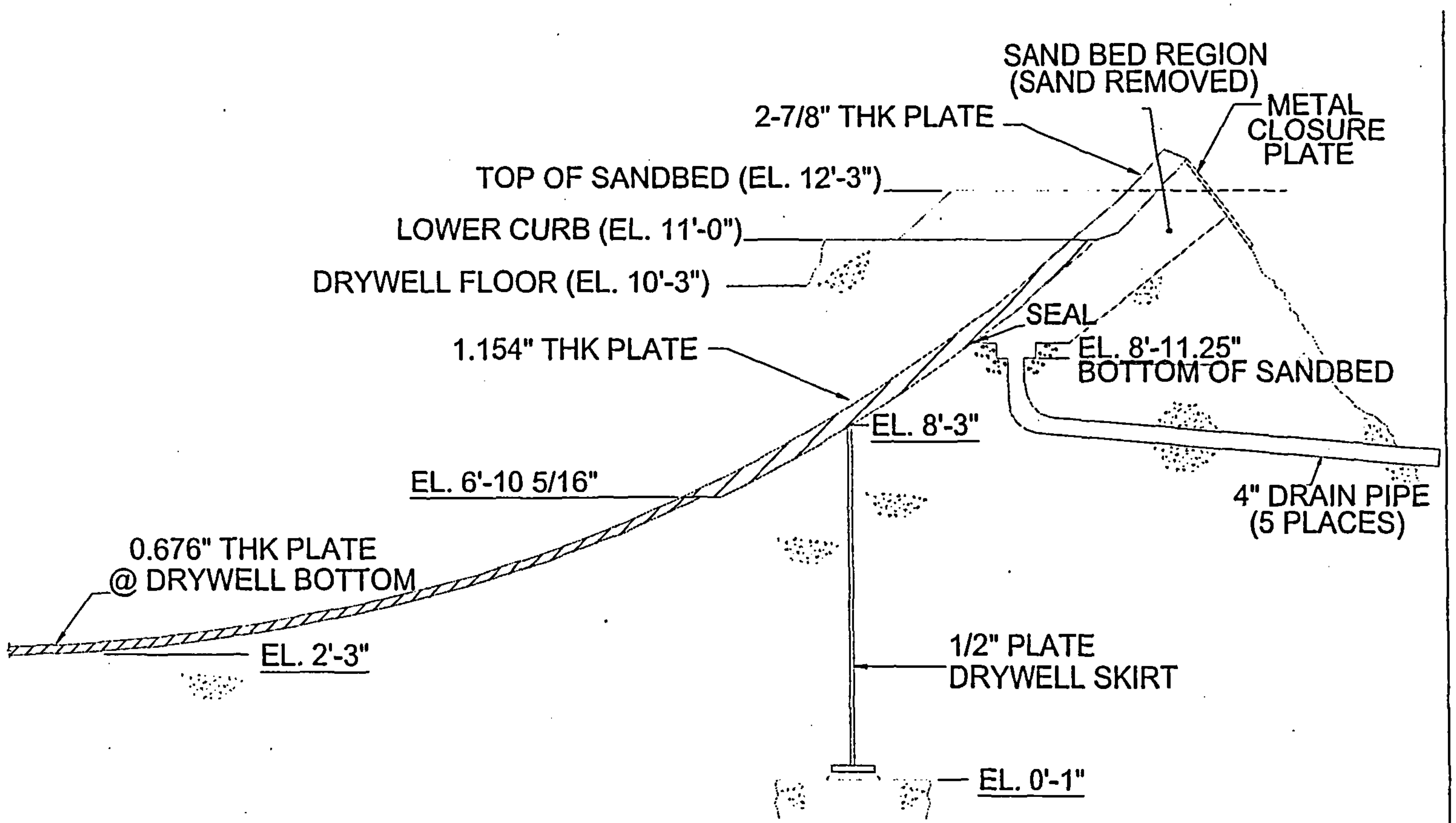
Sand Bed Region



Lower Drywell Shell



SECTIONAL VIEW OF SAND BED REGION