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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

March 6, 2008

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on March 6, 2008, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

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

1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 550TH MEETING

5 ADVISORY COMMITTEE ON REACTOR SAFEGUARD

6 (ACRS)

7 + + + + +

8 THURSDAY

9 March 6, 2008

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11 ROCKVILLE, MARYLAND

12 + + + + +

13 The subcommittee met at the Nuclear

14 Regulatory Commission, Two White Flint North, Room

15 T2B3, 11545 Rockville Pike, at 8:30 a.m., William A.

16 Shack, Chairman, presiding.

17 PRESENT:

18 WILLIAM A. SHACK CHAIRMAN

19 MARIOV. BONACA VICE CHAIRMAN

20 SAID ABDEL-KHALIK MEMBER AT LARGE

21 GEORGE APOSTOLAKIS MEMBER

22 J. SAM ARMIJO MEMBER

23 SANJOY BANERJEE MEMBER

24 DENNIS C. BLEY MEMBER

25 MICHAEL CORRADINI MEMBER

1 PRESENT: (CONT.)

2 OTTO L. MAYNARD	MEMBER
3 JOHN D. SIEBER	MEMBER
4 JOHN STEKAR	MEMBER
5 SAM DURAISWAMI	DESIGNATED FEDERAL OFFICIAL
6 CHARLES BROWN	NRC STAFF
7 GARY HAMMER	NRC STAFF

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

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

2 (8:11 a.m.)

3 OPENING REMARKS

4 CHAIRMAN SHACK: The meeting will now come

5 to order.

6 This is the first day of the 550th meeting

7 of the advisory committee on reactor safeguards.

8 Here in today's meeting the committee will

9 consider the following: license renewal application

10 for the James A. FitzPatrick Nuclear Power Plant;

11 license renewal application for the Vermont Yankee

12 Nuclear Power station; selected chapters of the WER

13 associated with the ESBWR design certification

14 application; a subcommittee report regarding the

15 license renewal application for the Wolf Creek

16 Generating Station; and preparation of ACRS reports.

17 A portion of this meeting related to ESBWR

18 may be closed to protect information that is

19 proprietary to General Electric-Hitachi nuclear

20 energy.

21 This meeting is being conducted in

22 accordance with the provisions of the Federal Advisory

23 Committee Act. Mr. Sam Duraiswami is the designated

24 federal official for the initial portion of the

25 meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's session. We have several people on a bridge phone line listening to the discussions related to the Vermont Yankee license renewal. To preclude interruption of the meeting, the phone line will be placed in a listen-in mode during the presentations and committee discussions.

A transcript of portions of the meeting is being kept, and it is requested the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so they can be readily heard.

I begin with some items of current interest.

Mr. Peter Wen joined the ACRS staff as a senior staff engineer on March 3rd, 2008. He has been with the NRC since 1982 working in several areas including event assessment policy and rulemaking issues and license renewal. Also he worked in Region 1 for six years.

Prior to joining the NRC he worked for Westinghouse for four years performing safety analysis of nuclear systems and Basco Services for four years working on nuclear plant design and construction.

1 Mr. Wen has B.S. and M.S. degrees in
2 mechanical engineering from the Taiwan CD University
3 and M.S. degrees in aerospace and nuclear engineering
4 from the Georgia Institute of Technology.
5 Welcome aboard.
6 (Applause)
7 CHAIRMAN SHACK: Mr. Gary Hammer who has
8 been with the ACRS staff for 18 months is leaving on
9 March 18th to join the component integrity performance
10 and testing branch in the Office of New Reactors.
11 During his tenure on the ACRS staff he has
12 provided outstanding technical support to the
13 committee and reviewed numerous regulatory and
14 licensing matters including the ESBWR design
15 certification application, several license renewal
16 applications, digital I&C and fire protection matters;
17 dissimilar mold metal weld issue; and several
18 regulatory guides and generic letters.
19 His dedication, professional attitude,
20 hard work and attention to details, in depth knowledge
21 of regulatory matters, and willingness to assist
22 others are very much appreciated.
23 Thank you, and good luck in your new job.
24 (Applause)
25 CHAIRMAN SHACK: Our first item of business

1 is the license renewal of the FitzPatrick Nuclear
2 Power Plant, and Mariov will lead us through that.
3 FITZPATRICK LICENSE RENEWAL APPLICATION PRESENTATION
4 VICE CHAIRMAN BONACA: Good morning.
5 We are here to review the final SER and
6 the license renewal application of the James
7 FitzPatrick NVP.
8 The license renewal subcommittee met in
9 September 5th, of 2007, to review the SER with open
10 items. At the time there were two open items. One
11 had to do with fluence calculations that supported a
12 number of TLAs, and the other open item was the
13 environmentally assisted fatigue. The - both open
14 items have been closed. The final SER has been
15 received. And we are here to review it together with
16 the staff and the licensee.
17 During the subcommittee meeting we
18 reviewed the aging management program for the
19 containment. There is a Mark I containment, including
20 shell and torus. And we had a number of questions
21 relating to some pitting identified by the licensee in
22 the torus. I believe the licensee has dedicated quite
23 a few slides today to address this issue, and because
24 that is an area where the subcommittee has a number of
25 questions.

1 With that I will turn to Dr. P.T. Kuo of
2 the staff.
3 STAFF INTRODUCTION
4 MR. KUO: Thank you, Dr. Bonaca, and good
5 morning to all members.
6 My name is P.T. Kuo for the record. I'm
7 the director of the division of license renewal.
8 I also would like to introduce my staff
9 who are responsible for carrying out this review.
10 To my left is Ronnie Framovich. She is
11 the branch chief for the project management branch
12 too, and to her left is Tommy Le who is the project
13 manager leading the review of this application. And
14 to his left is Glenn Meyer who is the team leader for
15 the Region 1 inspection, for the license renewal
16 inspection, at the plant.
17 Sitting in the audience we also have a Dr.
18 Ken Chang. Can you show your hand please? He is the
19 branch chief of the audit review of branch one who is
20 responsible for the mechanical and the materials
21 engine review area.
22 And we also have Dr. Raj Auluck who is the
23 audit review branch chief two. His area of
24 responsibilities are the structural and electrical
25 engineering areas, plus scoping methodology review.

1 (Telephone interruption)

2 MR. KUO: We also have a technical - we

3 also have technical reviewers.

4 CHAIRMAN SHACK: Do we need this now or is

5 this just for Vermont Yankee?

6 (Telephone interruption)

7 MR. KUO: As Dr. Bonaca described, the

8 staff has completed the technical review of the

9 FitzPatrick licensing application, and we have

10 forwarded to the committee the final safety evaluation

11 report last month. And we have resolved two open

12 items listed in the report to our satisfaction.

13 This morning we are going to brief the

14 committee with the result of our review. And the

15 presentation will be led off by the applicant first,

16 and the staff's presentation follow.

17 With that, if there are no questions, I

18 will turn over the presentation to the applicant

19 first.

20 ENTERGY INTRODUCTION

21 MR. DIETRICH: Good morning. I'm Pete

22 Dietrich, the site vice president at James A.

23 FitzPatrick. And I'd like to thank you, Mr. Chairman,

24 and the members of this committee for the opportunity

25 to present our license renewal status to you this

morning.

I'd like to introduce the members of our team. I'll begin with the gentleman at the front table, moving from left to right: Gary Young is a manager in our business development and license renewal group.

Next to him is Alan Cox, technical manager, also focusing primarily on license renewal. Steve Bono is a director of engineering at James A. FitzPatrick and will be the lead for our presentation this morning.

Next to him is Joe Pechacek, our manager of programs and components engineering at the plant.

Immediately to my right here at the table is Brian Finn, our nuclear safety assurance director, and Jim Costedio, our licensing manager.

And sitting in the front row on this side Rick Plasse who is our licensing lead; Larry Leiter who is one of our technical leads at the facility; Thomas Moskalyk, structural lead; and Artie Smith who is our RSI engineer.

We figured for our discussion this morning specifically regarding the torus pitting these were the individuals to bring with us to answer any questions that the full committee has.

1 And with that I'll turn it over to Steve.

2 MR. BONO: Good morning. Again, thank you

3 for the opportunity.

4 Just a quick agenda. Again I'm Steve

5 Bono. I'm director of engineering at FitzPatrick.

6 We'll go through a brief site description,

7 licensing history and some major improvements that we

8 have done to the station; plant performance; and then

9 also the making of our license renewal project.

10 We do as previously mentioned, we do have

11 a special presentation based on our site committee

12 topics that we'll go over our torus and our torus

13 monitoring and the corrosion that we are monitoring in

14 our torus.

15 We have some specific details. We were

16 asked to bring some data in how we are evaluating the

17 conditions that we have.

18 Just a quick briefing on the site.

19 General Electric is our NSSS supplier; also a turbine

20 generator supplier, and Stone & Webster was our AE and

21 constructor.

22 We are a BWR-4 vintage plant with a Mark

23 I containment, and we'll speak a lot about our

24 containment later.

25 Rated at 2,536 Megawatts thermal which

1 equates to about 880 megawatts electric, we are a
2 once-through cooling system with Lake Ontario as our
3 heat sink, and located on the shores of Lake Ontario.
4 And right now our staff complement is about 660
5 people.
6 So just a brief licensing history.
7 Construction permit issued in May of 1970. Operating
8 license in 1974, and we began commercial operations
9 July 28th, 1975.
10 As far as changes to our license,
11 significant changes, in 1996 we did do a 4 percent
12 power uprate, and uprated our license. In November of
13 2000 the license was transferred from the New York
14 Power Authority to Entergy, owner/operator of the
15 facility, and we submitted our license renewal
16 application on July, 2006, and as noted our current
17 operating license expires in October of 2042.
18 Some major improvements we made to the
19 station: listed some here to give just kind of an idea
20 of the types of upgrades that we do. I'm not going to
21 go through all of these in detail. Many of these
22 dealt with changes in the industry going through
23 hydrogen water chemistries in conjunction with things
24 to improve the asset.
25 I'd more like to point out that the

1 processes that we identify as major capital
2 improvements in a 15-year plan, we call that our asset
3 management plan. So we look ahead 15 years.
4 Some highlights as we look forward for our
5 asset management plan.
6 CHAIRMAN SHACK: Those look like hardware
7 changes I'd make if I was planning a sizable power
8 uprate. Is that in the works?
9 MR. BONO: The question is, is power uprate
10 in the works for FitzPatrick? I can tell you we are
11 embarking on a feasibility study right now. We need
12 to know the results of that feasibility study before
13 we can commit that power uprate is immediately in our
14 plans.
15 Some of these items, turbine rotor
16 replacements, some of that was due to steam path
17 losses, so when you see those they would appear to be
18 gauging for the future. But we had in our HV turbine
19 we were monitoring by a phased array, we had some
20 indications, and in our low pressure turbine rotor we
21 had some steam path losses.
22 So those were the driving influences for
23 those replacements, although they do, as you record,
24 they do match well with if we were going to upgrade
25 the facility.

1 But some highlights as we move forward, we
2 are looking at the age of some of our large motors.
3 That is an issue that we have plans to resolve, motor
4 degradation over the next couple of years.
5 Here we're looking at a research pump
6 overhauls, both pump and motor, as original plant
7 equipment. We're at the point where those are aging.
8 Condenser retubing, just being on the
9 shores fo Lake Ontario, that's a frequency established
10 to go and retube our condenser.
11 And then also a scheduled transformer
12 replacements with our main transformers and our aux
13 transformers.
14 MEMBER ARMIJO: What is the condenser
15 tubing material?
16 MR. BONO: Right now the condenser tubing
17 material is two part; the higher tubes up in the steam
18 path are titanium, and the other tubes are brass, an
19 admiralty brass material. So with that comes certain
20 chemistry concerns that we matter. Right now all
21 below any established chemistry guidelines or limits.
22 But we will reevaluate the material as part of the
23 retubing to give us better chemistry performance.
24 CHAIRMAN SHACK: So the material to retube
25 has not been chosen as of yet?

1 MR. BONO: The material to retube has not
2 been chosen at this point.
3 Any other questions on our master
4 management plan or looking forward?
5 Current plant status, plant is operating
6 today, plant is operating today at 100 percent power.
7 It's been operating for 117 consecutive days.
8 Just big picture, we are in a cycle. We
9 started up from our refueling outage in the fall of
10 2006, and we have a refueling outage scheduled for
11 this fall.
12 Coming out of that refueling outage we did
13 have a 250-day run which is the longest for a
14 FitzPatrick history to come out of an outage with that
15 length of run. We view that as a measure of the
16 quality of the work we do, and also the scope of the
17 work we do to maintain the equipment systems
18 functioning well.
19 So some of the items of interest in this
20 outage. Some we've covered specifically in our asset
21 management plan. But one is our main transform
22 replacements, and we are tracking that as an end-of-
23 life item. So we are replacing those transformers.
24 Our core spray motor replacements, our
25 core spray system, one of our ECCS systems, is

1 original plant motor; we're monitoring that. No known
2 degradation right now, but that is just more of
3 managing the aging.
4 And then we have a yard breaker, again no
5 degraded condition in our switch yard. But the
6 breaker is sized to prevent single faults, and right
7 now the duty on that based on changes in the grid, we
8 need to change that to meet the conditions of our ISO
9 agreement with our grid suppliers.
10 And then we have some screen house
11 upgrades. This last fall we went through a period
12 where we saw some environmental changes, and we had
13 some algae intrusions that we had seen at FitzPatrick
14 historically.
15 We have made some upgrades to the facility
16 to address that. But we've got some more upgrades
17 that we are planning, and also to replace our screens
18 from the age and condition of the screens.
19 So there are some screen house upgrades
20 that we'll do as an asset management improvement.
21 In our license renewal project we do have
22 a project team that is experienced. It's multi-
23 disciplined, and it's also an Entergy fleet team, so
24 it utilizes both a corporate process but also our own
25 onsite technical lead and onsite resources.

1 The benefit of doing this as a fleet is,
2 we've incorporated lessons learned from the other
3 applicants, and we have some of the Entergy fleet that
4 is further in the process than we are for license
5 renewal. So we've incorporated lessons learned from
6 that. And we also get feedbacks from their audits and
7 their inspections.
8 So learning becomes a continuing process
9 within the Entergy process, and that continues even
10 after our original amendment submittal. An example of
11 that is another facility had some scoping concerns
12 over spatial effects. Based on that feedback we went
13 and did additional walk downs at FitzPatrick and we
14 confirmed that we had done the proper scoping.
15 So that was a way we took a lessons
16 learned from another facility and applied it back even
17 though our amendment had been in to make sure we had
18 no additional concerns.
19 VICE CHAIRMAN BONACA: Those were the
20 scoping issues at the BY?
21 MR. BONO: Those ere the scoping issues at
22 Vermont Yankee. So we'll hear more about that in BY's
23 presentation.
24 We do some internal reviews, both a safety
25 review committee and quality assurance as well as our

1 own peers, using our Entergy processes. And all
2 internal comments are resolved prior to submittal of
3 the amendment.
4 As part of our project we did review our
5 application and evaluate against the goal. We
6 identified that of the 36 programs, 10 were
7 consistent. Twenty were consistent with some
8 exception or enhancement, and then six were plant
9 specific.
10 We're tracking all of the commitments in
11 an Entergy commitment tracking system that has
12 oversight and requires elevated levels of management
13 closure, or approvals, before they can be closed.
14 VICE CHAIRMAN BONACA: The majority of
15 programs have had exceptions. Could you comment on
16 the complexity of dealing with that? Because if I
17 looked at them and the corespondents, with the NRC,
18 the IRIs and all the discussions going on is another
19 world.
20 Did you find Gall too prescriptive, too
21 narrow?
22 MR. COX: Let me try to answer that. The
23 exceptions were fairly minor - my name is Alan Cox, by
24 the way. I think I introduced myself.
25 The exceptions we had again in a lot of

1 cases were fairly minor, things such as the code year.
2 I believe at the VY presentation we went through and
3 tried to categorize these things, and I think we had
4 very similar exceptions in the FitzPatrick case.
5 Steve mentioned there were 20 programs
6 with enhancements or exceptions. A lot of those were
7 enhancements instead of exceptions, so it's making the
8 program consistent with the Bell report.
9 Again, I don't think we had a lot of
10 trouble dealing with it. Some of the things were
11 cases maybe where the GALL was prescriptive in terms
12 of code year or addition. Some of them were the same
13 exceptions that we talked about that you heard about
14 yesterday.
15 The standards for diesel fuel monitoring,
16 it's just a little bit of ambiguity in GALL if you
17 will, because it represents two stacks when one of
18 them may be all that applies to your particular plant.
19 In general there were a few exceptions,
20 but they didn't present any major problems for us.
21 MR. BONO: And as I mentioned, we have 25
22 commitments at the end of our evaluation. There are
23 36 aging management programs. We currently have 17
24 programs in place without enhancements. Nine programs
25 that are in place but will require some enhancement.

1 And we have 10 new programs.

2 One aspect of being a fleet here and with
3 boiling water reactors of similar vintage, we are
4 looking at the commitments from the other stations in
5 developing programs in kind of a fleet approach.
6 We'll be able to use the resources from both Pilgrim,
7 Vermont Yankee and ourselves to come up with programs
8 that we can write program documents and implement as
9 a fleet.

10 Just to go over as stated our draft SER
11 was issued in July, 2007 with two open items . Those
12 items were reactor vessel fluence. An update on that
13 issue: we did revise our calculations, and they've
14 been updated to meet Reg. Guide 1.190. Those were
15 being approved through our processes, and submitted in
16 November. And those have been reviewed and accepted.

17 In the environmentally assisted fatigue
18 area, we have established a commitment where we will
19 comply using our fatigue monitoring program, using the
20 NRC approved version of the code. So we will refine
21 our analysis of the cumulative usage factors, and then
22 establish corrective actions to prevent exceeding any
23 design limits during the period of extended
24 operations.

25 So we've established that as a commitment.

1 That will be done two years prior to the period of
2 extended operation.
3 Final SER was issued in January of 200.
4 And as noted both of those items have been closed, so
5 it was issued with no open items.
6 MEMBER BANERJEE: How are your steam dryers
7 doing?
8 MR. BONO: We do monitor our steam dryers
9 using our vessel internal program.
10 MR. PACHACEK: Lee me just - my name is Joe
11 Pachacek. I'm engineering programs and components
12 manager.
13 Our steam dryer overall is doing very
14 well. We have completed a very detailed inspection
15 based on better as-built drawings. It's been one of
16 the challenges in the industry identifying all the
17 welds that come back. We did do our last outage, an
18 as-built on the dryer, completed our inspections.
19 We do have several indications. The last
20 outage we actually did a repair, it was on an upper
21 vertical weld where we had several pieces of metal
22 stuck together.
23 Overall though compared to what's been
24 seen in the industry our dryer is in very good
25 condition.

1 CHAIRMAN SHACK: Those indications you
2 attributed to SCC?
3 MR. PACHACEK: I don't - Ms. Gallic, can
4 you comment on that, whether it was a GSCC?
5 MR. COSTEDIO: I believe those indications,
6 I believe they are fatigue related.
7 MEMBER ARMIJO: At the last subcommittee
8 meeting we had a lot of discussion on that, whether
9 they were IGSCC or fatigue related. And there was
10 some skepticism on the part of the committee members
11 on how could you tell with just a visual surface
12 inspection whether something was IGSCC or fatigue.
13 I'm not sure it really matters since you
14 will be monitoring the components anyway. But at some
15 point it wouldn't hurt to have General Electric or
16 whoever made the assessment for you to give you a nice
17 white paper on why they believe it's IGSCC in a few
18 cases.
19 MR. PACHACEK: That is a good comment, and
20 we'll capture that comment and follow up on it. Thank
21 you.
22 CHAIRMAN SHACK: I mean if you are doing a
23 condition assessment, the crack growth rates are going
24 to be quite different.
25 MEMBER ARMIJO: Right, but in the final

1 analysis, is sit enough to make a difference from your
2 inspection to your -
3 CHAIRMAN SHACK: Well, you might have to
4 inspect more frequently if you thought you were
5 dealing with fatigue rather than IGSCC.
6 MR. PACHACEK: And just to clarify a point,
7 too, that the NSSS providers, since General Electric
8 was very involved in it and actually performed the
9 assessment of the last indication we saw on the
10 operator was the dryer, and they did make a
11 recommendation to repair it.
12 That indication was fully excavated and
13 weld repair was effected.
14 MEMBER ARMIJO: Okay, just on the issue of
15 your reactor vessel fluence, after all this was said
16 and done, and you finally have a fluence calculation
17 that the staff agrees is correct, where did you wind
18 up compared to the original fluence calculations?
19 Were the original fluence calculations that you
20 submitted much more conservative? And could you give
21 me kind of a ballpark level of -how different were the
22 two analyses?
23 MR. BONO: What I do have is, I have all
24 locations. I'm not sure I can fully answer your
25 question, but I can turn it over to my technical

staff.

I do have information that all areas were considered with the exception of one areas, the lower intermediate shell, and the location is shell two, the surface fluence was 3.11 e^18th was the condition we ended with, but all other areas, our existing calculations were more limited than the revised.

MEMBER ARMIJO: That was the only one where the original estimate was nonconservative?

MR. BONO: The original was 3.05 e^18th; we went to 3.11.

(Laughter)

MR. BONO: Everything else moved in the other direction.

MEMBER ARMIJO: Okay, I don't worry about that.

MR. BONO: The change, pretty minute. But that was the only one that had a change in the other direction; I'll say that.

MEMBER ARMIJO: Okay.

MR. BONO: Any other questions on our open item?

As we talked about in our subcommittee meeting, we had lengthy discussion on our torus. Again this is more to depict the Mark I containment.

1 Obviously the area that we'll be talking about is the
2 torus.
3 The torus has a 30-foot cross-section
4 diameter across the torus. I've got some data as we
5 approach this that will show the indications that
6 we're monitoring, their locations and where they are
7 below water level.
8 VICE CHAIRMAN BONACA: Before you get to
9 the torus you may want to say something to the whole
10 committee regarding the condition of the shell and the
11 program you have. I mean, do you have a plan to do
12 that?
13 MR. BONO: Yes, I have a plan to go into
14 detail on the condition of the shell, torus shell.
15 VICE CHAIRMAN BONACA: That's only the
16 torus. I'm talking about the drywall. Because then
17 we had a subcommittee present information about a
18 drywall that was positive, clearly indicated that it
19 was in good condition, and you justify your aging
20 management program, particularly you have a leakage
21 monitoring system and so on and so forth.
22 MR. BONO: We have a leakage monitoring
23 system where any leakage when it reaches a certain
24 threshold is enunciated. We have done - fluoroscopic,
25 thank - fluoroscopic inspection in our sand drain

areas and found no moisture.

And we do a caulk seal inspection every refuel outage. And that has - we've got no known degradation of the caulk seal.

VICE CHAIRMAN BONACA: And you have had no bellow leakage?

MR. BONO: No identified bellows leaking events at FitzPatrick.

VICE CHAIRMAN BONACA: Okay.

MR. BONO: And like I said, our inspection of the sand rains indicate no evidence of moisture. We've done boroscopic inspections. Most recently, in 2007 we've done a boroscopic inspection of that area.

VICE CHAIRMAN BONACA: For the benefit of the other members of the committee, I mean we reviewed this in detail, and we got a positive impression. So we emphasized that the presentation to the full committee should focus mostly on the torus. But the committee has -- members had said that the shell program was good.

MR. BONO: Tom or any other technical people, anything you'd like to add there? Any questions?

Focusing in on our torus was the issue where we were asked to bring more information, more

1 data. We do have a ton of work regarding our
2 containment inspection, in service inspection program.
3 It does implement the IWE code provisions.
4 As we note here our requirements from ASME
5 Section 11, the 2001 edition, through the 2003
6 addendum.
7 So we do have a program that is built off
8 the code requirements. Some different inspection
9 criteria. I wasn't going to go through a lot of
10 these. I was going to kind of focus more on what
11 we're seeing.
12 But we do do our general visual once every
13 period, our wetted surfaces once every interval, and
14 our event system once again 100 percent once every
15 interval.
16 Moisture barriers, 100 percent during each
17 inspection period. Containment surface areas, we do
18 a detailed visual; 100 percent of surface areas
19 identified. And then we do have a surface area grid
20 where we use ultrasonic testing, and I'll go into this
21 in much greater detail.
22 But we do 100 percent of the minimum wall
23 thickness locations that we have identified. And then
24 we've established each of those based on the code
25 sections referenced there.

1 VICE CHAIRMAN BONACA: First of all, the
2 previous slide, you mentioned accessible surface area
3 once every period. And then you talk about once every
4 interval.
5 Could you explain what period and
6 intervals are?
7 MR. PACHACHEK: Arturo Smith, if you would
8 address the question regarding intervals and
9 inspection frequency please.
10 MR. SMITH: I'm not sure I understood the
11 question. Could you repeat that please?
12 VICE CHAIRMAN BONACA: You have the
13 statement below those bullets, once every period.
14 Below that it says, 100 percent once every interval.
15 And again, interval. Would you explain to the
16 committee what period and intervals are?
17 MR. SMITH: Those intervals-period is in
18 accordance with the code, which is 3-1/3 rd years.
19 Each interval is 10 years based on the ISI program.
20 And it's broken up into three periods within that 10
21 years.
22 FitzPatrick currently has five years
23 within an ISI interval, and we have broken that up
24 into two outages, one in the period, one in the second
25 and two in the third.

1 So the period is equivalent to 3-1/3
2 years. An interval is equivalent to the 10 years.
3 VICE CHAIRMAN BONACA: Okay. Now you -
4 this is a standard IWE program, but you have
5 identified some level of pitting throughout the torus.
6 Could you describe that, and also how your program is
7 adopted to that?
8 I mean when you have findings typically
9 you enhance your program, right?
10 MR. BONO: I think we will go through that
11 as we move forward. I do have a slide that depicts
12 the location of our fitting, the magnitude of it, and
13 then also how we go about - that those identified
14 areas increase monitoring.
15 MEMBER BANERJEE: What is the material of
16 the torus, carbon steel?
17 MR. BONO: Carbon steel.
18 MEMBER BANERJEE: So this is what, pitting
19 that you see in the carbon steel? What is the reason
20 for the pitting?
21 MR. BONO: Water.
22 MEMBER BANERJEE: Yeah, but water and what?
23 MR. PACHACHEK: Wet surface, yes.
24 MR. MOSALYK: The torus is coated with
25 carbo-zinc 11. It's an inorganic zinc coating. The

1 inorganic zinc depletes over time, and the result of
2 the depletion, pits form in certain locations.
3 MEMBER BANERJEE: Do you have an idea what
4 has happened to that zinc coating over a long period
5 of time? Has it tinned, or has it just tinned in
6 specific spots? Or what has happened there?
7 MR. MOSALYK: Well, it has thinned over
8 time. During 1998 when we had a torus drain down, and
9 desludging a bit at that time, there was a very
10 extensive inspection performed of the entire torus,
11 lower section, wetted surfaces.
12 One particular area of interest where
13 there was a water zinc depletion, there was an
14 inspection done of that entire area, a pitting
15 inspection done of that entire area, and the pitting,
16 there was some pitting in that area, not very
17 significant, about zero four, about inch-deep pits.
18 So it did not reduce the shell much in that area at
19 all.
20 Other areas we segmented the torus into -
21 we have 16 bays. We have five shell plates in lower
22 sections for each bay, and we segmented each one of
23 those five shell plates into six sections. So we have
24 about 480 sections, that we actually inspected and
25 determined defects in those areas.

1 So we have a clean map of the lower
2 section of the torus. It's kind of a baseline map
3 that was used for subsequent routine inspections.
4 MEMBER BANERJEE: How do you determine the
5 pit depths?
6 MR. MOSALYK: The pit depths in 1998 were
7 determined with visual pit gauge readings.
8 Inspections were done for all the segments, all 480
9 segments, using pit depth gauges.
10 Subsequent to that during - we've been
11 using ultrasonic examinations in the areas of
12 interest, the pitted areas of interest.
13 MEMBER BANERJEE: How big are these pits in
14 diameter?
15 MR. MOSALYK: The diameter of the pits?
16 Well, they vary somewhat. We have not gotten to a
17 point where we have needed to characterize the pits in
18 a lot of detail because we are still well above our
19 normal design limits. We have a limit for general
20 thickness for the torus. And at this point even the
21 deepest pits are still well above that point.
22 MEMBER BANERJEE: What is that point?
23 MR. MOSALYK: Our design point is point
24 five zero three inches. We have a nominal shell
25 thickness of .632 inches. Specification, the material

1 specification, the A516 Grade 70 plate steel is
2 allowed to be provided in thicknesses up to point zero
3 six thicker than the nominal.
4 We are finding that many many of our
5 plates, for the most part almost all of our plates,
6 the actual plate thicknesses that were supplied are
7 well above that point. And we determined that by
8 ultrasonic examinations.
9 MEMBER BANERJEE: So did I hear you right
10 that the pits can be as much as half an inch deep?
11 CHAIRMAN SHACK: No, a tenth.
12 MEMBER BANERJEE: What did I hear?
13 CHAIRMAN SHACK: A tenth, maybe.
14 MR. MOSALYK: Our pit depth, our actual pit
15 depth to date has been .076 inches, tracking from -
16 yeah -
17 MEMBER BANERJEE: Point zero seven six.
18 MR. MOSKALYK: Correct.
19 MEMBER BANERJEE: And your current depth
20 is, the largest pits is point zero four you said? I'm
21 totally confused. Please repeat. What have you
22 found? What is the limit? And what is the pitting?
23 MR. BONO: Okay, what we have found is, our
24 maximum pit depth of all the areas we've mapped and
25 all the areas we've ultrasonically examined is .076

1 inches.

2 MEMBER BANERJEE: Okay, and what is the

3 limit?

4 MR. BONO: Our limit is .503 inches. That

5 is our design requirement for general thickness.

6 MEMBER BANERJEE: That is half an inch,

7 right?

8 MR. MOSKALYK: That's the plate thickness.

9 MR. BONO: That is the required plate

10 thickness based on design analysis.

11 PARTICIPANT: What Pedro is asking is, what

12 is the maximum pit depth that you can tolerate.

13 MR. BONO: Okay, the maximum pit depth we

14 can tolerate.

15 MEMBER BANERJEE: Exactly.

16 MR. BONO: Okay, the maximum pit depth we

17 can tolerate, what, nominal thickness - we know our

18 plates are thicker than that, but if you took the

19 nominal thickness and subtracted .503 it would be .129

20 inches. That would be from nominal.

21 I think we have a slide coming up that

22 goes through a lot of this, so you can visualize it.

23 MEMBER BANERJEE: Okay, that'll be -

24 MEMBER MAYNARD: The pit depth is as

25 important as how much metal do you have left. Your

1 wall thickness can vary, so it's not so much the pit
2 depth, because you may - it be occurring in a thicker
3 or it could be in a thinner. It's how much metal is
4 left below the pit.
5 MEMBER BANERJEE: Yes, what I'm interested
6 in is understanding what margin you have, and how long
7 it's taken you to eat that margin out, you know, sort
8 of extrapolating that experience. So you are going to
9 talk about this?
10 MR. BONO: I think we have a slide coming
11 up that presents the data in a way that will - that
12 visualizes it better that I think will help in this
13 area.
14 So I think, Tom, we can go through a lot
15 of the data when we get to that slide, so we do -
16 MEMBER BANERJEE: So let's defer it.
17 CHAIRMAN SHACK: Well, you are also
18 comparing at this point to nominal, and you could
19 actually have much greater localized depth
20 information.
21 MR. BONO: And we have found that our plate
22 thickness, although nominal as Tom presented, like I
23 said it's as high as 10 percent above nominal in many
24 locations. So that's why the UT measurements becomes
25 a very accurate way of monitoring where we stand

1 compared to the design limit.

2 MEMBER MAYNARD: I think when we get to

3 that point what we need to talk about is, what is the

4 minimum wall thickness required, and what is your

5 current minimum wall thickness that you have. That's

6 where you get how much margin you have.

7 VICE CHAIRMAN BONACA: The other issue is,

8 you know, how many pits do you have in a certain area.

9 Because you may have just one location, and so the

10 wall is still solid and capable; and you have a

11 pinpointed one. Or you may have significant pitting

12 in an area; then you worry about - so those are pieces

13 of information you'll want to give us.

14 Now I know you do have a slide to address

15 the specifics of that.

16 MR. BONO: That's correct. I think a lot of

17 this will come together. We've got a slide that I

18 think represents this data in better detail. We've

19 just got a couple of sundry slides I need to work

20 through to get us there.

21 From a summary statement, we haven't

22 identified any interior, exterior surfaces areas that

23 have substantial corrosion or pitting.

24 I say substantial corrosion or pitting, as

25 kind of a measure of when we would meet the code

1 required threshold for augmented inspections. So we
2 have not reached any of those thresholds.
3 We have no areas that are excessive wear
4 from abrasion or erosion that's caused a loss of the
5 coatings, deformation, material loss. And I think Tom
6 explained why we are seeing the pitting based on the
7 zinc depletion in our coding system.
8 VICE CHAIRMAN BONACA: So let me understand
9 the mechanism now. You have this coding depletion,
10 and if it goes beyond a certain amount of depletion,
11 you expose the metal. And then you have pitting
12 forming from that.
13 And it seems to me that certainly you are
14 going to monitor new areas where you may have that
15 happening, and I think you are addressing that later.
16 But also I would like to know what your corrective
17 actions are. Because I mean if I understand it you
18 have left the uncovered material exposed to the water,
19 so you must have some idea.
20 So I trust you have a monitoring program.
21 But the question I have in my mind is, is your
22 corrective action appropriate. What are you waiting
23 for before you record those portions? I mean that -
24 if - answer that whenever you get there, but that's
25 something I need to understand.

1 MEMBER BANERJEE: Also, for me I need to
2 understand the mechanisms. Is it a zinc oxygen redox
3 couple that's forming? Or how is it - you know zinc-
4 oxygen makes a little battery. So if you walk me
5 through that it would be useful.
6 MR. BONO: And when we get there, Tom, I'll
7 ask you to help us with some of the technical issues.
8 We have identified 29 locations, so it was
9 asked how many locations we had. We've got 29
10 locations on the interior surface of the torus.
11 Again, it was referenced, and they are below the code
12 threshold for augmented inspections.
13 What we have implemented is kind of an
14 increased monitoring, which we do more frequent
15 examinations based on these locations so that we can
16 understand the rate and how much margin we have in our
17 plate thickness.
18 MEMBER ARMIJO: Just to make sure I
19 understand, are all these pitting locations at the
20 waterline, below the waterline, above the waterline,
21 or all over the place?
22 MR. BONO: I think when we go to the next
23 slide, I think this might help to visualize it. This
24 is a picture looking down on the bottom half of our
25 torus. So these are the plates. Our torus is

segmented in 16 bays. There are five plates per bay, and then we've sectioned each plate into a six-section grid that we can use for monitoring.

So you can see in these locations that as you move on the inner or outer diameter of the circles here you're getting closer to the water level, because you are looking down on the bottom.

And as you're in the middle of the diameter, then you are looking at the bottom of the torus. So we're looking down on the bottom half of the torus.

MEMBER CORRADINI: Just so I understand, so you're unwrapped it, so if I look at the inner radius I'm at the bottom of the floor. So if I look at the outer radius of the donut I'm at the top of the torus?

MR. BONO: This is - imagine this is like a cross-sectional view looking down on the torus.

MEMBER BANERJEE: The plan view.

CHAIRMAN SHACK: The middle of the donut is the bottom.

VICE CHAIRMAN BONACA: My understanding, and tell me if I'm correct, is that the pitting was in the weathered area?

MR. BONO: Yes, this is all - the water level is about one foot from the center line of the

1 torus.

2 VICE CHAIRMAN BONACA: I was just asking

3 the other question.

4 MEMBER ARMIJO: Yeah, so you are not seeing

5 any pitting above this.

6 MR. BONO: Areas above the torus when we

7 operate our containment system is inerted with

8 nitrogen. We don't have the environment that really

9 produces corrosion above water level. That is

10 inspected 100 percent every outage we do a visual.

11 MEMBER ARMIJO: Is the whole torus coated?

12 MR. BONO: Yes.

13 MEMBER ARMIJO: All surfaces, whether it's

14 below water, above waterline?

15 MR. BONO: Yes. The entire course of the

16 torus is coated with the same Carbozin system, four to

17 nine mils thickness, original application.

18 MEMBER BANERJEE: So point zero four nine

19 inches; is that it, the thickness?

20 MR. BONO: The thickness, four to nine mils

21 for original dry thickness application.

22 MEMBER BANERJEE: So some of these pits

23 have actually gone through the full thickness of the

24 coating?

25 MR. BONO: Of the coating.

1 MEMBER BANERJEE: Yeah, do you see any
2 acceleration over time of the pitting, or has it been
3 sort of uniform over time?
4 MR. BONO: I think to answer that I need to
5 go through a little bit more of the history and see if
6 we can answer that through the presentation.
7 In 1998, as Tom said, we did 100 percent
8 visual, and we did fit gauge measurements of all these
9 locations.
10 What you see on the left of the donut is
11 kind of our inspection period with each mark, and then
12 also as an example above that you can see how we
13 designate an area.
14 So it'll be bay followed by plate, and
15 then the actual UT exam thickness reading.
16 So as Tom discussed, our plate nominal
17 thickness is .632 inches with a designed minimum
18 thickness of .503 inches for the lower half of our
19 torus.
20 Now the plate nominal thickness -
21 CHAIRMAN SHACK: But again that would be
22 general corrosion. So you could have even localized
23 deeper than that. That would be a conservative
24 estimate of your margin.
25 MR. BONO: Yes, if I understand your

1 comment is that when we say the plate design thickness
2 minimum, that's the entire torus. And we apply that
3 design requirement to a localized area because we feel
4 that's conservative.
5 And as Tom displayed, we have seen
6 variations as high as plate thickness of .69 inches.
7 So -
8 MEMBER ABDEL-KHALIK: What's the design
9 basis for the .503 minimum thickness?
10 MR. BONO: Tom, question is the design
11 basis for the .503 inches, the design basis? What are
12 the assumptions?
13 MR. MOSKALYK: The design basis is based on
14 ASB Section 3 code and is the number of load cases you
15 consider. The most limiting that is used to establish
16 that number if membrane and bending, membrane stress,
17 bending stress, combination produces .503. There are
18 other combinations that would produce thicker results,
19 but that is the most limiting.
20 MEMBER ABDEL-KHALIK: Is the set point for
21 the water level in the torus, has that ever changed?
22 MR. BONO: Not to my knowledge. Larry?
23 No, the set point has not changed; maintained the same
24 torus water level through -
25 MEMBER ABDEL-KHALIK: Does the water get

1 stagnant in the torus or does it move around?

2 MR. BONO: Other than, you know, we do a

3 lot of surveillance testing where we run our systems

4 that might draw suction or discharge into the torus,

5 I wouldn't necessarily say the water level is

6 stagnant, because we do do a lot of surveillance

7 testing, required surveillance testing of our ECCS

8 systems.

9 MEMBER ABDEL-KHALIK: So what is the

10 frequency of stirring it up, roughly? Once a year?

11 Twice a year?

12 MR. BONO: We run some of our safety

13 systems quarterly that would stir this up. At a

14 minimum I would tell you that the steam discharges in

15 the torus, quarterly, we run those safety systems that

16 use the steam that would discharge in the torus.

17 MEMBER STEKAR: Do you have a suppression

18 pool cleanup system that's normally running?

19 MR. BONO: No, we do not have a torus

20 cleanup system. We monitor torus sludging. We do an

21 evaluation. And then we schedule a de-sludge of our

22 toruses during outages.

23 So I can go through the schedule here in

24 a minute. I will point out that right now our most

25 limiting location - and as we said, we apply our most

limiting localized area as if it were across the whole torus - our most limiting location would give us remaining surface life out to 2026. So we have that.

We do have in our asset management plan provisions that we would address this before we reach design limitation.

MEMBER ARMIJO: That is assuming a linear continuation of where you are now?

MR. BONO: That's assuming a linear continuation. We do have a schedule, and it's listed on there, right there, as we go back.

We are going back to some of these ultrasonic that would give us more of an ultrasonic to ultrasonic point to give us - so we could refine that. And if that projection changes we'll take corrective action

MEMBER BANERJEE: The point of my question was, did you see some acceleration in the finding of your pits? And since when did you start this monitoring program? How long have you had it in place?

MR. BONO: We've had this monitoring program since the 1998 drain down where we identified these pits.

MEMBER BANERJEE: So in 1998 you found some

1 pits. And since that time you found more pits, right,
2 or have you?
3 MR. BONO: To my knowledge we haven't
4 identified any new locations since 1998. 1998 was our
5 last torus drain down, removed the water. We can do
6 underwater inspections, but that was the last
7 opportunity where we had the water dry.
8 CHAIRMAN SHACK: Was that your first drain
9 down?
10 MR. BONO: No, we had down drain downs
11 prior to '98 when we had done the Mark I containment
12 modification.
13 CHAIRMAN SHACK: Which was when?
14 MR. BONO: 1979 and 1983.
15 MEMBER BANERJEE: But then you had some
16 repairs in 2005?
17 MR. BONO: I'm sorry?
18 MEMBER BANERJEE: You had some repairs in
19 2005. Did you have to drain the torus when you fixed
20 that break?
21 MR. BONO: No, we had a torus indication
22 based on stresses from our IPSE discharge line, which
23 was the - in the subcommittee presentation we had a
24 thru-wall indication in our torus because of a very
25 localized stress was our IPSE steam line. And the

1 manner in which it discharged into the area without a
2 sparger on it.
3 So we've gone, we've taken corrective
4 action at the design deficiency, put the sparger in.
5 But we had to repair the area. We actually did not
6 have to drain down to do that. We were able to do an
7 underwater repair.
8 VICE CHAIRMAN BONACA: Right, but so what
9 you said before however is that you have not inspected
10 new areas.
11 MEMBER BANERJEE: It's not that you haven't
12 found; you haven't tried in the last 10 years.
13 MR. PACHACHEK: Tom already talked about
14 the size of the UT grids that we do that would
15 essentially provide an enhanced inspection area,
16 similar to what we discussed at the subcommittee
17 meeting.
18 MR. MOSKALYK: We performed a thorough
19 inspection in 1998 of the entire torus, the entire
20 wetted surface of the torus. And that provided a
21 baseline for our future inspections.
22 From that point we categorized the number
23 of pits, there were 29 locations we categorized for,
24 we eventually prioritized future inspections for those
25 locations.

1 Of course the deepest pits we inspected
2 with ultrasonic first, and we are now working on
3 priority twos and priority threes which are more
4 shallow pits.
5 We do reinspections of the areas of the
6 deepest pits. We'll be repeating inspections for our
7 deepest pits this coming refueling outage.
8 MEMBER BANERJEE: So the ultrasonics that
9 you have been doing have been looking at, say, how
10 these pits are changing with time? You are doing
11 that?
12 MR. MOSKALYK: That is correct.
13 MEMBER BANERJEE: So are you finding any
14 acceleration rather than a linear behavior with regard
15 to both the depth of the pits as well as the number of
16 the pits over time?
17 MR. MOSKALYK: We've got the pits, we have
18 performed - we are just now going to be performing
19 ultrasonics in the same location a second time. So we
20 had visual data from 1998. We performed ultrasonics
21 in a number of areas. We are going back to repeat
22 several areas for a second time. So from a standpoint
23 of ultrasonic inspections and measuring using the same
24 method, we will just be performing our second
25 ultrasonic this coming outage in the deepest pit

1 areas.

2 So that'll establish an actual pit growth

3 rate. We have the pit gauge measurement from 1998 and

4 ultrasonic from, if you look at the schedule, some

5 2004, 2006 locations, and then we'll have a second

6 ultrasonic so we can better establish and refine that

7 pit growth or loss of material rate, and then we can

8 refine our extended service life.

9 VICE CHAIRMAN BONACA: So what you are

10 saying is that you have not in every location repeated

11 your ultrasonic testing yet?

12 MR. BONO: Right, we have the original pit

13 gauge measurements. We have ultrasonics, and in the

14 fall, this outage, you can see we've got scheduled

15 repeats from areas in 2004 as well as our most

16 limiting bay that we identified in 2006, we are going

17 back in.

18 VICE CHAIRMAN BONACA: You are planning to

19 develop a rate, a progression, that you will use in

20 your program? I mean is it defined in your program

21 that you will do that?

22 MR. BONO: Yes, we have an engineering

23 evaluation that we have a calculation that we will

24 refine, and that's what - like I said, we take the

25 minimum thickness and apply that generically to the

1 whole torus. We feel it's conservative. And then
2 that comes up with the remaining surface life. And
3 then we have plans to take corrective action prior to
4 the service life.
5 VICE CHAIRMAN BONACA: But the question I
6 have in my mind, still, as you said, that in the worst
7 location you project 2028 for the possible failure.
8 MR. BONO: 2026, that's correct.
9 VICE CHAIRMAN BONACA: Reaching the
10 criterion. So for that one you seem to have developed
11 a rate of progression which you are using.
12 MEMBER BANERJEE: Assumed a linear rate.
13 VICE CHAIRMAN BONACA: Okay, a linear rate.
14 Now the question I have is, when are you going to take
15 action? I mean what criteria do you have for
16 intervention to mitigate this situation?
17 MR. BONO: We do have an approved coating
18 program, Tom, that is an underwater repair for areas.
19 We do have that approved. We do have that ability to
20 do that.
21 Maybe you can go into more - we've got
22 priorities established in our calc, and we are looking
23 at where we would hit design thickness, and then we
24 would plan back from that to do a coating repair.
25 MR. MOSKALYK: We do have a qualified

1 coating system for underwater repairs if we need to do
2 that. As a matter of fact we applied that coating
3 system to the area which we repaired near the IPSE
4 sparger discharge that same system. That system is
5 used by a number of plants; it's been effective. And
6 that would be our plan for these areas.
7 CHAIRMAN SHACK: How big are your
8 ultrasonic grids? When you're looking at these
9 things, how much of an area are you looking at?
10 MR. SMITH: How we set up these grids, we
11 have these pit locations, or at least these degraded
12 areas that we've found. And then around that we'll
13 open up a 3X3 or 2X 2 and then we'll scan these 100
14 percent. We don't actually take point to point
15 readings, but we actually scan 100 percent of this,
16 although it is gridded, so we'll know if we find any -
17
18 MR. BONO: So we have a three foot by three
19 foot grid, and we will do 100 percent scan in that
20 grid.
21 MEMBER ABDEL-KHALIK: We are covering a lot
22 of surface.
23 MEMBER MAYNARD: But you are not recording
24 each - and you are recording a result of those scans.
25 If you find an indication in that area that you would

1 go back and do more specific at that point?

2 MR. SMITH: That is exactly what we would

3 do. We define that, and then what we would do is take

4 specific readings around it to get a rate of the

5 thickness in that area to see if there are any other

6 instances of it occurring.

7 MEMBER SIEBER: The scans are from the

8 outside in?

9 MR. BONO: Correct.

10 MEMBER SIEBER: So the surface prepped and

11 all that kind of stuff does not disturb it?

12 MR. BONO: That is correct.

13 MEMBER ABDEL-KHALIK: These original

14 measurements were done with a depth micrometer?

15 MR. BONO: The 1998 measurements, that's

16 correct.

17 MEMBER ABDEL-KHALIK: How do those compare

18 accuracy-wise with the ultrasonics?

19 MR. BONO: Tom, do you have that

20 information.

21 MR. MOSKALYK: Pretty close. Our deepest

22 pit that we determined in 1998 was point zero eight

23 inches. Deepest pit in our subsequent inspections

24 using ultrasonics we established a .076. It appears

25 that the visual pit depth gauge measurements appear to

1 be a little more conservative from the standpoint of
2 showing a little bit deeper pits.
3 MR. PACHACHEK: Just if I may too, just to
4 clarify a previous question that was asked, whether or
5 not our program includes requirements to take any new
6 - any changes in the UT data as far as pit depth and
7 incorporate that into the program, the answer is yes.
8 So we would redo the calculation to
9 reproject from in-service life whenever we have any
10 new information that's gained as a result of doing UTS
11 on the shell.
12 VICE CHAIRMAN BONACA: And you have
13 identified the corrective action that you will
14 implement?
15 MR. BONO: That is correct. And we would
16 also track that in our corrective action tracking
17 system.
18 MEMBER BANERJEE: If necessary you could
19 record the whole thing, right?
20 MR. BONO: If necessary, that's correct.
21 MEMBER BANERJEE: So what you are really
22 doing, you are using these 29 locations as leading
23 indicators.
24 MR. BONO: That is correct. We are using
25 those as leading indicators, and as I stated, we're

1 applying that to the whole torus for getting remaining
2 service life.
3 MEMBER BANERJEE: So this is part of your
4 aging management programs?
5 MR. BONO: This is part of our containment
6 in service inspection program, that is correct.
7 MEMBER BANERJEE: And you have sort of
8 identified certain things that would lead to you need
9 to repair ceratin areas, and eventually perhaps even
10 recoat the whole thing if necessary, as part of your
11 program?
12 MR. BONO: That's correct, that's part of
13 the program. That's why we project the remaining
14 surface life so we can take that corrective action
15 before we hit any design limit.
16 CHAIRMAN SHACK: Of course as you mitigate
17 each of these areas with a protective coating you've
18 lost a leading indicator.
19 MR. BONO: That is correct. Now one thing
20 I should point out, in 2010 we will be doing a torus
21 de-sludge operation that will - we will also 100
22 percent underwater inspection. And that is also the
23 best opportunity to patch any areas, when we have a
24 de-sludge operation.
25 CHAIRMAN SHACK: Now the 100 percent

1 underwater that's a visual? You go in with a
2 boroscope, basically?
3 MR. PACHACHEK: Divers.
4 MR. BONO: Divers.
5 MR. PACHACHEK: Divers that are qualified
6 in accordance with the necessary ND programs for
7 visual inspections.
8 MEMBER SIEBER: But it is still a visual.
9 MR. PACHACHEK: It is visual.
10 MEMBER ABDEL-KHALIK: But the logic of this
11 whole program assumes that all the sort of pitted
12 locations had been identified in '98?
13 MR. BONO: We are using the pitted
14 locations in '98 as kind of a leading edge indicator.
15 In 2002 - or I'm sorry, 2010 when we do the de-
16 sludge, obviously, we will have new data that we will
17 then use as inputs into our evaluation.
18 VICE CHAIRMAN BONACA: And that will tell
19 you if you have additional locations that are
20 developing. Now that would also be the opportunity to
21 determine in fact that you have identified leading
22 indicators, that have some other location where you
23 have something happening and you don't know.
24 MR. BONO: That is correct.
25 MEMBER BANERJEE: I guess this is a very

1 nonlinear process, because once you go through that
2 zinc, things start to move much more quickly right?
3 Or not?
4 MR. BONO: I don't know that I can say
5 that. What I can tell you is that we've got the - we
6 use the pit depth measurements to an ultrasonic to
7 establish a rate, then we'll go back with another
8 ultrasonic and refine our rate.
9 We are using a linear right now because we
10 have two points. But as we get more data we'll revise
11 that, and we'll be able to project a much more
12 accurate rate.
13 MEMBER BANERJEE: But just from the point
14 of view of logic, the coating is there to prevent the
15 initiation. Once you go through the coating things
16 are going to go much faster, right? You would think
17 so.
18 MEMBER SIEBER: If you get pitting, the
19 coating has already lost its integrity.
20 MR. BONO: You will begin corrosion from
21 the point of the loss of the coating.
22 MR. LEITER: This is Larry Leiter from
23 FitzPatrick System Engineering. The advantage of zinc
24 is that it serves as a sacrificial anode, and so it
25 will to some extent fill in its own gaps. The zinc

1 coating doesn't have to be continuous. Minor flaws
2 don't - minor flaws can personally correct themselves.
3 They will redeposit. What happens though is that the
4 pit that forms that has penetrated through the coating
5 now behaves as a pit and corrodes in that manner.
6 MEMBER BANERJEE: What I known of zinc
7 electrodes, you start to get dendrite formation on
8 deposition.
9 MR. LEITER: You can.
10 MEMBER BANERJEE: So how is this coating
11 repairing itself?
12 MR. LEITER: It's the - you have the large
13 expanse of zinc, the entire coated area, so it can
14 deposit back in.
15 MEMBER BANERJEE: Explain this to me in
16 some detail. Is this a common thing that you expect
17 this to repair itself by electrodeposition?
18 MR. BONO: Our program monitoring is using
19 these as leading edge, and then we establish a rate
20 through the ultrasonic.
21 MEMBER BANERJEE: Yeah, I see what you are
22 doing, which is fine. But I would have thought that
23 the rate would accelerate, I mean just looking at the
24 physics of what is going on, or the chemistry in this
25 case.

1 But Bill is much more of an expert on
2 this.
3 MEMBER MAYNARD: I need to take a step back
4 here and make sure I understand.
5 When we're talking about a pit depth, are
6 we talking about a pit in the coding or a pit in the
7 actual metal?
8 MR. BONO: Metal.
9 MEMBER MAYNARD: Okay, so when we are
10 talking about a pit, we've already gone through the
11 coating?
12 MEMBER BANERJEE: My understanding is that
13 the pitting starts because you have lost the coating.
14 MR. BONO: That is correct.
15 MEMBER SIEBER: There is no mechanism to
16 accelerate that, once you've breached it.
17 MEMBER MAYNARD: The other thing, on your
18 program for corrective action, does it require action
19 before exceeding all your margin? Or does it require
20 action before say 80 percent of your margin is gone?
21 MR. BONO: Right now, Tom you can correct
22 me if I'm wrong, but it requires corrective action
23 before exceeding the design margin. I don't know that
24 we have a threshold established at 50 percent or 70
25 percent of design margin.

1 We obviously are looking at the
2 opportunity to do a torus repair, torus coating, is in
3 refueling outage, so we'll be projecting years so we
4 could plan and execute that activity.
5 MR. MOSKALYK: The inspections we do in
6 2008, reinspecting 10 locations that had been
7 previously inspected, and that information will
8 provide us with a pit growth rate. From that point we
9 can make determinations as to what corrective actions
10 we would take when it would be appropriate.
11 MEMBER MAYNARD: If it's not in your
12 program I would suggest that you at least consider -
13 you don't want to be in a situation where you are
14 projecting right on the limit, and you go to that
15 limit and you go in there and find out you had
16 exceeded it a little bit. A lot of programs, you
17 really take action before you reach the limit.
18 VICE CHAIRMAN BONACA: Absolutely. I mean
19 that - you know, that is an essential element of any
20 aging management program is in fact when you start
21 your corrective action how do you mitigate this
22 situation.
23 We are projecting by linear extrapolation
24 that you are going to go through, you are going to
25 exceed the limit.

1 MR. BONO: We'll get to it, a localized
2 area on that where the pit would be less wall required
3 that our design of the entire torus.
4 VICE CHAIRMAN BONACA: You don't want to
5 get that close.
6 MR. BONO: I understand. I understand the
7 input, and I said we can refine the program to add a
8 criteria at what point to take corrective action.
9 We're projecting in a manner to plan and execute this
10 I think that we account for that. We don't plan on
11 going into an outage to get these types of
12 measurements, and obviously if we have to we'll take
13 action.
14 But we are trying to project it in a
15 manner that we will do it before we reach design
16 limits.
17 MEMBER BANERJEE: But minimum thickness is
18 based on your projected local loss?
19 MEMBER SIEBER: As we pressurized it.
20 MR. BONO: That is correct. The design
21 minimum, .503 plate thickness, is based on - assumes
22 some loads, and that's based on our local loads.
23 MR. MOSKALYK: Primarily based on pressure
24 and hydrodynamic loads. So the hydrodynamic loads are
25 evenly distributed. They are not a local condition.

1 CHAIRMAN SHACK: No, he meant loca or main
2 steam line break. What axis is the limiting load.
3 (Simultaneous speakers)
4 MEMBER BANERJEE: Why do you assume it to
5 be evenly distributed? Because you are getting bubble
6 collapse, right, where you are injecting. And this
7 bubble collapse gives you very strong pressure waves.
8 So why do you assume it to be uniformly
9 distributed?
10 MR. MOSKALYK: Well, uniformly distributed
11 because the condition would be for the downcomers into
12 each of the bays. The downcomers are evenly
13 distributed throughout the entire torus.
14 MEMBER BANERJEE: How many downcomers do
15 you have?
16 MR. MOSKALYK: Forty-eight parts, 96.
17 CHAIRMAN SHACK: Does this thing lose the
18 nitrogen inertia in an outage? Or is it always - when
19 does it become oxygen saturated or air saturated?
20 MR. BONO: During outages.
21 CHAIRMAN SHACK: During outages.
22 MR. BONO: During outages we do an above-
23 water-level inspection and our containment -
24 CHAIRMAN SHACK: Is open to the atmosphere?
25 MR. BONO: - is open to the atmosphere and

1 de-inerted.

2 CHAIRMAN SHACK: So you pick up air every

3 fueling outage then?

4 MR. BONO: Every two years, and then when

5 we re-inert.

6 MEMBER ARMIJO: When you re-inert, do you

7 do any kind of sparging of the water to get rid of

8 dissolved oxygen and CO2 from the water, exchange it

9 with the atmosphere in the gas phase if you will?

10 Because without oxygen you are not going to have any

11 corrosion.

12 So is there anything in your plan to

13 actively keep the water as minimally aggressive as

14 possible?

15 MR. BONO: I don't - you guys, I'll ask my

16 technical team to back me up, but I don't know of any

17 - where we planned a sparging of the torus. We do do

18 - as I described before, we do do quarterly

19 surveillance testing where we do stir up the torus,

20 and we do have alutions like that. But it's not what

21 I would call a plan.

22 MEMBER ARMIJO: So you don't transfer the

23 benefits of inerting from the gas phase into the water

24 phase where you have the problem?

25 MR. BONO: Not in the planned fashion I

1 think you are asking.

2 MEMBER SIEBER: You still have dissolved

3 oxygen in the water to some extent?

4 MEMBER ARMIJO: You'll have some. But if

5 you took advantage of the nitrogen you did have you

6 might save yourself a lot of grief later on.

7 The other issue is, do you have - is the

8 worst pitting concentrated under the sludge area, away

9 from the sludge area? Where is the problem more

10 severe, or most severe?

11 MR. BONO: I don't know that we could say -

12 we could correlate that. And Tom, I don't know if

13 you can help. I don't know that there is any

14 correlation to sludge location and pitting location.

15 MEMBER ARMIJO: But just tell me, where are

16 your deepest pits, and where are they on that map?

17 MR. BONO: It's in the indigo bay is one

18 that we identified in 2006. Again, you say deepest

19 pit, we use the minimum wall thickness; that's our

20 least amount of wall thickness. And we are going

21 back, we identified that in our 2006 outage, and we

22 are going back to that location in our coming outage.

23 MEMBER ARMIJO: Where would that be on this

24 map?

25 MR. PACHACHEK: It would be here.

1 MEMBER ARMIJO: Of that's near the bottom.
2 Potentially it could be a sludged area.
3 MR. BONO: Potentially; I don't know that
4 we have a correlation that would suggest that.
5 MEMBER BLEY: The orange spots here is your
6 schedule for doing the inspection? Or the locations?
7 You don't have a map like this of where you found the
8 pits?
9 MR. BONO: These are the locations.
10 MEMBER BLEY: Oh, those are where the pits
11 are? So you can tell, they are not all down in the
12 bottom.
13 MR. BONO: That is correct.
14 MEMBER ARMIJO: But the point is, you ought
15 to know where your most severe problem is, and you
16 ought to know the mechanism that is causing the
17 pitting, and it's not generalized, so it's not a
18 homogeneous environment there underneath that water
19 level.
20 And the question comes up, do you have any
21 kind of a chemistry model for this torus either by
22 your contractors, consultants that are telling you,
23 this is from a first principle, this is where your
24 problem will be most severe. This is what you should
25 do to monitor it or actually mitigate it without

1 waiting umpteen years to get to the edge of a cliff.

2 And it just seems like there is a lot more

3 information that you could get to protect this course

4 rather than just monitoring and inspecting it once in

5 awhile.

6 MR. BONO: We do not have a chemistry model

7 to answer that question. And during our 2010 de-sludge

8 operation I think we'll get the kind of data you're

9 looking for as far as locations compared to conditions

10 in the torus at locations.

11 MEMBER BANERJEE: What is the sludge,

12 generally? The composition of the sludge?

13 MR. BONO: You guys can you help me there,

14 the composition of the sludge?

15 MR. MOSKALYK: I don't know, it would be

16 corrosion products.

17 MEMBER BANERJEE: Zinc and iron oxides.

18 Some carbonates?

19 MR. MOSKALYK: I don't know about

20 carbonates.

21 MEMBER BANERJEE: Oxides maybe?

22 MR. MOSKALYK: Oxides, correct.

23 MEMBER BANERJEE: Well, carbon dioxide. It

24 would be interesting to know.

25 Because does the - do these react with

1 boric acid and things?

2 CHAIRMAN SHACK: There's no boric acid.

3 MEMBER BANERJEE: But they inject during

4 the - in an accident.

5 MR. BONO: We have some accident scenarios

6 where we inject boric acid.

7 MEMBER BANERJEE: Clearly -

8 (Simultaneous speakers)

9 MEMBER SIEBER: Once you do that, you'll be

10 doing a lot of other things.

11 MR. BONO: It hasn't been done at

12 FitzPatrick, nor do we plan on doing it.

13 MEMBER SIEBER: This represents 30 years of

14 degradation.

15 MR. BONO: That is correct.

16 MEMBER BANERJEE: The reason I'm asking

17 about the sludge, of course you de-sludge, is, are

18 there any potential reactions between the boric acid

19 and the sludge? The Germans have identified some

20 reactions.

21 MEMBER SIEBER: There is no boric acid.

22 MEMBER BANERJEE: No, during the injection.

23 CHAIRMAN SHACK: He's got an accident going

24 on, and he's putting in the boric acid.

25 MEMBER BANERJEE: I'm worried about the

1 long term cooling of this system.

2 MEMBER SIEBER: After an accident?

3 CHAIRMAN SHACK: After an accident, yeah.

4 MEMBER BANERJEE: I'm always worried about

5 accidents. Not worried otherwise. So what happens

6 now? You've got boric acid in there. You've got this

7 sludge.

8 MR. BONO: I'm not aware of any

9 interaction. I'm not prepared.

10 MEMBER SIEBER: Actually, the degradation

11 that would occur due to the boric acid, the transient

12 pressures the container.

13 CHAIRMAN SHACK: I think he is worried

14 about generating some gases.

15 MEMBER SIEBER: The chemical reaction.

16 CHAIRMAN SHACK: Or reacting the sludge

17 with the boric acid.

18 MEMBER BANERJEE: We are drawing from the

19 sump to cool the system.

20 MR. BONO: Yes, it's a make up water source

21 through a strainer, ECCS systems have a strainer

22 designed to ensure we get net positive suction into

23 the ECCS systems.

24 MEMBER BANERJEE: You are going to talk a

25 little bit about the strainer system as you go on or

1 not?

2 MR. BONO: I had not planned on it. Again

3 our presentation was focused on managing the aging in

4 this condition of the torus.

5 MEMBER BANERJEE: Are these disc strainers

6 that you put in?

7 MR. BONO: They are disc-type strainers for

8 the ECCS strainers, that's correct, for our safety

9 systems.

10 MEMBER MAYNARD: They did cover that in

11 detail in the subcommittee meeting, and we went over

12 that a lot.

13 MR. BONO: We talked about the strainer

14 system because of the thru-wall indication we had.

15 Again, we covered that because - to show that that was

16 a design flaw, not an aging condition that needed to

17 be managed.

18 MEMBER BANERJEE: Anyway, if there is a

19 problem it'll be a generic problem. It's not your

20 problem.

21 MEMBER ABDEL-KHALIK: Typically when you do

22 these sludge removal operations, how much sludge are

23 you talking about? Tens or hundreds of kilograms?

24 MR. BONO: Tom, do you have that data as

25 how much, when we do a de-sludge operation? It is

1 based on ECCS strainer loading, and -

2 MR. MOSKALYK: Total sludge weight? Dry

3 weight of sludge will be approximately 3,000 when we

4 do the de-sludge in 2010?

5 MEMBER BANERJEE: Three thousand what?

6 MR. MOSKALYK: Three thousand pounds,

7 approximately 3,000 pounds dry sludge weight.

8 MEMBER BANERJEE: It's a lot.

9 PARTICIPANT: Is that physical process, or

10 do you have to acid clean to get that stuff out?

11 MEMBER BANERJEE: It plugged up the

12 strainers before.

13 MR. MOSKALYK: It's silty.

14 MR. BONO: It's like a - it's silty, so

15 it's filtering. And then when we dry the filtering is

16 the weight that Tom is talking about.

17 MEMBER BANERJEE: This was evenly

18 distributed in the submerged depths, what thickness of

19 metal would it correspond to, 3,000 pounds?

20 MR. BONO: Oh, the 3,000 pounds.

21 MEMBER BANERJEE: Just the mass balance,

22 evenly.

23 MEMBER SIEBER: That's not all metal.

24 MEMBER BANERJEE: Well, it's oxygen and

25 metal. Take out the oxygen. So remove the oxygen

1 from the mass.

2 CHAIRMAN SHACK: It's coming from

3 somewhere, right.

4 MEMBER BANERJEE: So what would be the

5 thickness of that? Do we have an idea of that? Three

6 thousand pounds, so let's say an oxide. You could

7 back-calculate it, right? Is this just a mil or two

8 or what is it?

9 MEMBER MAYNARD: If it's generalized.

10 MEMBER SIEBER: That's not all coming off

11 the torus there. That's coming basically out of your

12 entire steam system, feedwater system, everything.

13 MEMBER BANERJEE: That's true.

14 VICE CHAIRMAN BONACA: In the next slide

15 you make a statement regarding inerted nitrogen.

16 Could you -

17 MR. BONO: Just - I think it's a point we

18 made earlier that our containment, 95 percent, other

19 than every two years, is inerted, with the nitrogen

20 environment so that the systems above water level are

21 not prone to a corrosion or a corrosion atmosphere.

22 And then again just a summary statement

23 that our system, we look for the monitoring of these

24 surfaces, and we mitigate any degradation and coding

25 issues.

1 As I said before we take a localized area
2 and we apply it to the whole torus when we calculate
3 our remaining surface life.
4 MEMBER ABDEL-KHALIK: How many data points
5 do you expect to have for the depth of these pits
6 before the end of the current license period, 2014?
7 MR. BONO: We list our schedule there. We
8 will have 100 percent underwater visual in 2010.
9 MEMBER ABDEL-KHALIK: No, but I'm trying to
10 extrapolate as far as pit growth rate. How many data
11 points do I have at the worst location to be able to
12 extrapolate, to get anything better than linear?
13 MR. BONO: At the worst location we will
14 have the pit depth measurement, we've got one
15 ultrasonic. We've got an ultrasonic in 2008. The
16 results of that will prompt us that, you know, if
17 required we will do a two-year inspection to refine
18 that number of points and project out that.
19 So we'll have one every two years between
20 now and 2014.
21 VICE CHAIRMAN BONACA: By the way, on a
22 separate note, I mean we are going to have a
23 presentation from the staff, and the inspectors looked
24 at this problem so we'll hear about it.
25 MEMBER BANERJEE: When you say linear

1 extrapolation is it linear from the time the pits were
2 found, which is '98? Or linear from year zero?
3 MR. BONO: We have a linear from year zero,
4 but we refine that as we get - so we have the pit
5 depth; we have the ultrasonic; we'll have an
6 additional ultrasonic; so we'll refine that.
7 MEMBER SIEBER: Well, you started off with
8 a nominal thickness which may be large or small.
9 MR. BONO: And again with the localized
10 area and the way we do our ultrasonic, we've got a
11 good idea of the actual plate thickness.
12 MEMBER BANERJEE: The main thing is that
13 you will find the problem hopefully before anything
14 develops. This is the assurance we need.
15 MR. BONO: Right, and again, in 2010 we
16 will have 100 percent underwater visual that will
17 identify all areas.
18 MEMBER BANERJEE: So this thing is not
19 going to fall apart under a loss of coolant accident?
20 MR. BONO: I would not - I can say that
21 this will not fall apart during a loss of coolant.
22 MR. COX: I think there is one key point
23 that I wanted to point out here that we've kind of
24 been beating around, the criteria is based on the
25 measurement of a pit. So when we get to the minimal

1 wall thickness for that pit we are not out of margin,
2 and it's not - I'm not able to easily quantify it, but
3 there's a large margin in the fact that you are
4 looking at a pit and applying that depth or that wall
5 thickness as if it applied to the whole area in that
6 bay of the torus.
7 MEMBER SIEBER: You have a membrane type
8 calculation.
9 MR. COX: And again that is not clearly -
10 not something I can clearly give you a qualification
11 of and tell you what percent margin that is. But it's
12 a very large margin.
13 MR. MOSKALYK: Local fitting, if you look
14 at the local condition, we use AS&E code case, N480,
15 and it provides guidance as to how establish the
16 minimum thickness requirements at pits. And pit
17 lengths, so there are characteristics of the pits, pit
18 lengths and depths are used in that calculation.
19 And you can go much lower than that
20 depending on the characterized - you know, the
21 dimensions of the pit.
22 We are not using that. We don't expect to
23 be using that. But that is - that still provides a
24 code allowable method fo accepting pits below your
25 minimal wall.

1 VICE CHAIRMAN BONACA: We need to move on
2 now.
3 MR. BONO: We have one more slide, and it's
4 kind of a summary to a lot of what I've just
5 presented.
6 We do do general examinations monitoring
7 torus surfaces. We evaluate those conditions in an
8 approved engineering process of calculation, and we
9 extrapolate a localized area to the entire torus.
10 And then when we do our de-sludging in
11 2010 we will do another 100 percent underwater visual.
12 And then we monitor those points using
13 ultrasonics in our program.
14 VICE CHAIRMAN BONACA: Any questions for
15 the applicant?
16 There are none. I thank you for the
17 presentation. And we will hear from the staff now.
18 MR. BONO: Thank you.
19 MEMBER BANERJEE: You got away without a
20 diagram showing all these thicknesses.
21 MR. BONO: I think the best data we have is
22 what I provided.
23 MEMBER BANERJEE: But I was just saying a
24 diagram of these things. I'd like to see the
25 thickness of the wall, the pits, minimum, something

1 like that. Something.

2 NRC STAFF REVIEW SUMMARY

3 MR. LE: Good morning, Chairman, Dr. Shack.

4 My name is Tommy Le, and I'm a senior

5 project manager in the division of license renewal,

6 Office of Nuclear Regulatory Commission.

7 With me today I have Mr. Glenn Meyer,

8 he'll be coming up soon. And I have Mr. Roy Matthew,

9 who is a team leader for the NRR audit team. And then

10 in the audience I also have a scoping team leader, Mr.

11 Billy Rogers.

12 With that introduction I would like on

13 behalf of staff I'd like to thank you, Mr. Pete

14 Dietrich, the vice president, of FitzPatrick Nuclear

15 Power Plant and his management staff and engineering

16 staff for having hosted the staff several audit

17 inspections and many conference calls in the facility.

18 And of course we finished the audit before

19 three feet of snow that came about after.

20 On behalf of the staff I would like to say

21 that I appreciate enormously the staff who had

22 reviewed the FitzPatrick license renewal application.

23 And it's to their credit that the information is now

24 compiled in the safety evaluation, the open SER, open-

25 item SER we issued back in July, end of July, 2007.

1 And we issued the final SER on January 24 of this
2 year.
3 With that I would like to first go over a
4 summary of what we did during the September 2007
5 sector meeting. During that time we reported to the
6 subcommittee that the audit team had compiled 346
7 audit questions, and the technical staff have 118 IEI.
8 And the -with the audit evaluation and input from the
9 audit and safety review we issued the SER with the
10 open item on July 31st, 2000 with two open items, no
11 confirmatory item, and three standard license
12 conditions.
13 MS. FRANOVICH: Tommy, this is Ronnie
14 Franovich with the NRC staff. I can't find Glen out
15 there, so why don't you go on to your slides on the
16 NRC staff's evaluation, and then we'll come back and
17 cover the regional inspection when he gets here.
18 MR. LE: Thank you.
19 Along with that I would like to go on to
20 section two, scoping and screening review. And that
21 would be on slide #9. The scoping and inspection team
22 have performed the audit, and the conclusion fo the
23 audit team was that the application information had
24 included scoping and screening methodology that are
25 consistent with the requirement of 10 CFR 54.4 and

1 54.21(a)(1).

2 The onsite audit was performed during the
3 week of September 25 to 29 of 2006. And the staff
4 concluded that the SSC was within the scope of license
5 renewal and the subject of aging management review
6 consistent with the requirement of 51.4 and
7 54.21(a)(1).

8 On Section #3, this is the heavy work for
9 the NRR audit team. And we reviewed a total of 26 AMP
10 program, with 18 men in a program, of which we had 26
11 existing AMP and 10 new AMP. Two of the 10 new AMP
12 were at the finding of the staff, and communication
13 and two were added.

14 For the consistency with the law the
15 applicant have planned consistent quantity, consistent
16 with either exception, enhancement, in the six plant-
17 specific program. The result of aging management
18 review is that the audit team come up with 346 audit
19 questions. And all questions except two were resolved
20 onsite during the interfacing with the applicant
21 engineering staff. Two questions of which were
22 converted to IEI, one became a new aging management
23 program that we needed, and the other became an open
24 item.

25 The two open which I will return to during

1 the subcommittee meeting was, one was the fluence
2 calculation, and the other was environmental assisted
3 corrosion.
4 And so we will resolve that in Section #4.
5 At the end of the AMP and AMR audit there were a total
6 of 25 commitments submitted to the staff.
7 MR. KUO: Tommy, just to correct the
8 record, you said environmentally assisted the
9 corrosion. It is not. It is environmentally assisted
10 fatigue.
11 MR. LE: Oh, yes, I'm sorry. Yes, thank
12 you, Dr. Kuo. With all these dignitaries it kind of
13 make me humble.
14 (Laughter)
15 MR. LE: Section #3 conclusion based on the
16 review of the AMR and AMP the staff concluded that the
17 applicant had demonstrated that the effect of aging
18 was adequately managed so that the intended function
19 would be maintained consistent with the CLB for the
20 period of standard operation.
21 At this time I would like to turn over to
22 Mr. Glenn Meyer, who will talk abo9ut the regional
23 inspection, and then I will finish up with the Section
24 #4 PRAA.
25 MR. MEYER: Good morning. I apologize for

1 my late arrival. I was checking with my peers on
2 torus corrosion.
3 But I led the inspection that was done in
4 April of 2007. We basically had two purposes. We
5 addressed the scoping of non-safety related structure,
6 systems and components, and we also looked at the
7 implementation of aging management programs.
8 Within the scoping area our focus was
9 those non-safety SSCs whose failure could affect
10 safety components.
11 We looked at both the spatial interaction
12 and structural interaction; did the review by means of
13 reviewing the application drawings, looking at the
14 program procedures that they had, doing considerable
15 walk-downs of considerable areas that were safety and
16 non-safety to confirm the thoroughness of the job they
17 had done.
18 We did find some components and portions
19 of systems that they agreed needed to be added to
20 within scope, and there was an application amendment
21 to accomplish that.
22 Overall the spatial interaction was
23 generally thorough. The structural interaction was
24 sound, and we concluded that the scoping and screening
25 within our area of review met the regulatory guidance

1 and properly supported Entergy's license renewal
2 application.
3 MEMBER BLEY: May I?
4 MR. MEYER: Sure.
5 MEMBER BLEY: I wasn't at the subcommittee
6 meeting. Can you tell me a little more about what you
7 look for in the spatial and structural interaction?
8 MR. MEYER: All right. On your license
9 renewal they have non-safety systems and components -
10 VICE CHAIRMAN BONACA: Seismic? Go ahead,
11 I'm sorry.
12 MR. MEYER: Two over one can be part of it,
13 but the bulk of it tends to be, or spatially, would be
14 fluid systems that are in the vicinity of safety
15 systems and their failures, the fluids could affect
16 the safety systems.
17 And then a second component is the
18 structural part where they have attachments, typing
19 that is non-safety but it's attached to a safety
20 system, and the structural design includes structural
21 supports on the non-safety part. So they have to
22 extend the license renewal boundary into some part of
23 the non-safety system.
24 VICE CHAIRMAN BONACA: And then from what
25 you've told us you just found a few areas where they

1 had to look a little further than they had. No
2 inconsistencies means where they looked it seemed
3 okay.
4 MR. MEYER: Right. The general approach
5 was sound. We found a few areas that they had to
6 amend.
7 The second area was aging management
8 programs. And we looked at 22 programs to take a look
9 at the program implementation, both in terms of the
10 programmed procedures they have, the operating
11 experience evaluations, the records of prior
12 corrective actions that they have identified and
13 addressed to get a sense of how effective the programs
14 were or would be; also talk to the cognizant people in
15 terms of their understanding; and also went into the
16 plant and looked at systems as evidence of how the
17 programs were working.
18 And it was a mix of existing and proposed
19 programs.
20 Regarding aging management we concluded
21 that their aging management program support the
22 conclusion that aging effects will be managed. We are
23 part of the process, the regional administrator letter
24 to NRR, the NRR office director in January stated our
25 determination that Entergy had demonstrated the

capability to manage the effects of aging during the period of extended operations.

VICE CHAIRMAN BONACA: With regard to the torus, the inspection report says in fact that you have evaluated their aging management program, right?

MR. MEYER: Uh-huh.

VICE CHAIRMAN BONACA: And what is your judgment on that?

MR. MEYER: We do look at the - it's controlled by the ASME code, so we have periodic inspections under the current license where we go in and look during outages at the inspections they perform; the conclusions they draw, and the records and evaluations.

Our review during license renewal concluded that they're meeting their existing commitments. And part of their application for saying what they're going to do looks to be effective.

So it is something we periodically look at, and we also look at during license renewal, and found that the FitzPatrick program has been generally effective and met the regulations.

MS. FRANOVICH: Dr. Bonaca, if I could add, the staff, the technical staff and headquarters makes a determination of the program's acceptability. So

1 the tech staff from NRR may be able to answer that
2 question on how we determined the program was
3 effective.
4 Really the regional inspection looks at,
5 is it consistent with what they told us in the
6 application.
7 VICE CHAIRMAN BONACA: Okay.
8 MR. LE: Thank you, Glenn. Any questions
9 for Glenn?
10 I would go on with the report to the full
11 committee, the staff review of Section four TLAA.
12 TLAA, the plan specific safety analysis that involved
13 time limiting assumptions defined by the current
14 operator and must be listed in -- it was Section
15 54.21(c)(1) of any plan specific TLAA bay assumption,
16 a code requirement of 54.21(c)(2).
17 The - we - the staff look at the criteria
18 that all the SSC involved should be in the scope of
19 license renewal as both requirement of 54.14(a),
20 consider aging effect, involving the time limit
21 assumption defined to an operating term determined by
22 the applicant by making a safety determination, and
23 involve the conclusion and provide the basis for
24 conclusions related to the capability of the SSC to
25 perform the intended function and code requirement of

1 54.4(b).

2 And lastly they had to contain or

3 incorporate by the reference in the current licensing

4 basis.

5 With that criteria in mind, the staff

6 reviewed the TLAA and we identify two open item that

7 was reported to the subcommittee. One had to do with

8 reactor vessel fluence, and the original submittal

9 were not adhering to the reg guide 1.;190, and

10 mentioned previously by the applicant.

11 And so the staff identified this as an

12 open item on November 5th, of 2007. The applicant

13 provided the staff with a new calculation based on the

14 guidance of reg guide 1.190, and the NRR staff we had

15 Dr. Lambert Lewis who had looked at it, and he

16 concluded the methodology acceptable, and the new

17 value that is presented in the new report, bounded by

18 the initial value, and for that open item that we have

19 in the question, we would answer.

20 The second open item is the

21 environmentally existing fatigue, and this now has

22 been resolved. During the review the applicant had

23 provided the staff with commitment 20. In that

24 commitment the applicant had committed to comply with

25 10 CFR 54.21(c)(1)(iii) that mean that they will have

1 an aging management program to manage this
2 environmentally assisted fatigue.
3 With that we resolved the two open items,
4 and so for Section conclusion, the staff conclude that
5 for 10 CFR 54.3, the TLAA had listed adequately as
6 amended, and for 54.21(c)(1)(I), analysis remain valid
7 for the period of standard operation, or PEO, and for
8 (ii) the analysis projected by the end of the PEO and
9 for (iii) aging effect was adequately managed for the
10 period of standard operation.
11 And so the staff also concluded that
12 sufficient supplement to SAR had also been provided as
13 a requirement of 54.21(d). And the applicant had no
14 plan-specific exception called for in 21(c)(2).
15 In the next slide is the nominal standard
16 three license condition that the staff has imposed on
17 every renewed license once approved by higher
18 management.
19 The first license condition would require
20 the application to include the UFSAR supplement
21 required by 54.21(b) in the next UFSAR update as
22 required by CFR 58.71(e) following the issuing of the
23 renewed license.
24 The second license condition require
25 future activity identify in the UFSAR supplement to be

1 completed prior to the period of standard operation.

2 The third license condition require that

3 the applicant in the reactor vessel that are removed

4 or tested will meet the requirement of the ASME 185-

5 82, that they stay practical for the configuration of

6 the specimen in the capsule.

7 Any changes to the capsule withdraw

8 schedule, including spare capsules, must be approved

9 by the staff prior to the implementation. All

10 capsules placed in storage must be maintained for

11 future insertion. Any change to the storage

12 requirement must be approved by the staff as required

13 by Appendix A to Part 50.

14 With that overall conclusion, the staff

15 say that there is reasonable assurance that the

16 activity authorized by the renewed license will

17 continue to be conducted in accordance with CLB, and

18 that any changes made to the FitzPatrick Nuclear Power

19 Plant CLB in order to comply with 10 CFR 54.29 in

20 accordance with the act and the commission's

21 regulations.

22 With that the staff conclude its briefing

23 to the full committee, and we have a technical expert

24 standing by if you had any questions.

25 MS. FRANOVICH: Dr. Bonaca, at this time if

1 you would like the staff member who was responsible
2 for reviewing the torus aging management program is at
3 the table, Hans Ashar. He can address why the staff
4 determined that that program was acceptable.
5 CHAIRMAN SHACK: Good, let's hear that.
6 MR. ASHAR: I am Hans Ashar from the
7 Division of Engineering, NRR. I heard a number of
8 questions from the CRS members, and I'm trying to
9 grasp everything that was being asked, and I'm trying
10 to answer some of these questions if not all of them.
11 First thing as far as the torus corrosion
12 is concerned, let me give a slight history on how it
13 is, in the industry in general.
14 First time we heard about the torus
15 corrosion was 1988 or so, where Nine-Mile Point had
16 uncoated torus, and it was getting corrosion, and they
17 informed us about the corrosion. And we looked into
18 it based on what we understood from that particular
19 plant.
20 But as we went along in 1992, 1993, the
21 IWE program was not available even at that time
22 because we had not endorsed it. We heard about a
23 couple of other plants where they said they had coated
24 torus and still it was getting corrosion in a few
25 spots.

1 And we started looking at more and more
2 plants. And we said, hey, the tori in most of these
3 plants has some kind of corrosion. As a matter of
4 fact I have seen a couple of plants where the numbers
5 of pits in the torus is higher than 9,000.
6 And how-
7 CHAIRMAN SHACK: The coated plants?
8 MR. ASHAR: They are coated. They are
9 coated, yes.
10 This brought us to quite a bit - this
11 happened to a number of other plants that we already
12 reviewed before, that actually FitzPatrick has only 29
13 locations where they are to monitor, they can monitor,
14 isolate it. They don't have to have a plan and
15 everything worked out.
16 But when there are a lot more locations we
17 have reviewed them, and we have said that, hey, your
18 program - now I'm going to come to what are the items
19 you - basic requirements that addresses this
20 particular idea.
21 First thing the IWE requires that whenever
22 they find corrosion or corroded areas, whether it is
23 a drywall, a containment, BWR containment, BWR, it
24 doesn't matter, IWE allows them to have a 10 percent
25 corrosion of any kind without any questions asked.

1 Okay, this is the acceptable criteria in IWE.

2 If they go over 10 percent they are to do

3 engineering evaluation or take corrective actions,

4 okay. Now, in case of torus in drywell shell in

5 Oyster Creek, you heard a lot about drywell shell

6 corrosion, what happens is that they normally do the

7 engineering evaluation. And that is where they come

8 out with certain criteria and say that, hey, we are

9 going to meet - this is my minimum required thickness.

10 I'm going to meet it before it gets to that particular

11 point.

12 IWE also requires them to monitor those

13 areas where corrosion have been found through two

14 successive inspections to make sure that the thickness

15 is there and not progressing, and they are to take -

16 if it is progressing they are to make sure that the

17 corrosion rate is established, and then they can

18 propose the particular corrective action and take the

19 corrective action at that time.

20 Now when I looked at the program, the IWE

21 program in FitzPatrick case, I saw that they told us

22 in operating expedience that there are three locations

23 that they found a little slightly higher than design

24 thickness requirement. And I looked at the figures,

25 I so the corresponding IWE requirements, and I said,

1 hey, the program if it is to be appropriate, the way
2 they are handling and monitoring the particular areas
3 are quite okay.
4 And that was my basis for accepting the
5 IWE program that FitzPatrick has given to us. We have
6 some few questions on that, but they satisfactorily
7 answered those questions.
8 VICE CHAIRMAN BONACA: What you are saying
9 is that the IWE program contains the typical criteria
10 that you would expect in an aging management program?
11 MR. ASHAR: That is correct.
12 VICE CHAIRMAN BONACA: Altering intervals,
13 et cetera. So that is helpful. Thank you.
14 MR. MATHEW: Let me follow up - this is Roy
15 Mathew - the bore gives guidance regarding how you
16 manage the torus and drywell corrosion. It says you
17 have to use two aging management programs, which is
18 in-service inspection IWE program, and also the
19 leakage monitor program for CFR Appendix J.
20 So we reviewed these two programs, and
21 following that we reviewed their operating experience
22 too. Since they follow the goal guidance, and the
23 program is consistent with our guidance, we don't have
24 an issues.
25 VICE CHAIRMAN BONACA: Okay.

1 MR. MEYER: And I would like to add from
2 the inspection perspective, we did look at the
3 containment in-service inspection program. I believe
4 the inspector is Michael Modus who has spoken to you
5 on other occasions, and has a lot of experience in the
6 field. His writeup in the report said, the torus
7 degradation has been occurring for several years.
8 However Entergy has performed appropriate inspections,
9 analysis and repairs to demonstrate the structural
10 integrity of the torus. Entergy's program contains
11 requirements to continue inspections of the
12 containment, evaluations of the observed degradation,
13 and prediction of remaining service life during the
14 original license period and throughout the period of
15 extended operation.
16 He said that - you know we do in Region 1
17 have a number of Mark I containments, many of which
18 were built without coding and are dealing with similar
19 issues. And what we see from FitzPatrick tends to be
20 better than some of the other approaches. They are
21 all acceptable, and we feel that FitzPatrick has done
22 an appropriate job.
23 VICE CHAIRMAN BONACA: Good, thank you.
24 Any other questions for presenters? If
25 not, I give the meeting back to you.

1 CHAIRMAN SHACK: We are just a little bit
2 ahead of schedule, five minutes. But we'll go ahead
3 and take our break until 10:45.
4 (Whereupon at 10:22 a.m. the
5 proceeding in the above-
6 entitled matter went off the
7 record to return on the record
8 at 10:44 a.m.)
9 CHAIRMAN SHACK: I think we can come back
10 into session.
11 Our next topic is the final review of the
12 license renewal application for the Vermont Yankee
13 Nuclear Power Station.
14 And Dr. Bonaca is lucky enough to lead us
15 through this again.
16 FINAL REVIEW OF LICENSE RENEWAL APPLICATION FOR
17 VERMONT YANKEE NUCLEAR POWER STATION
18 VICE CHAIRMAN BONACA: It was kind of hard
19 to keep FitzPatrick and Vermont Yankee apart.
20 We met a month ago to review the
21 application for license renewal for Vermont Yankee.
22 And I believe we covered pretty much every item of the
23 agenda having to do with license renewal.
24 There was one remaining item that was left
25 because of the time; we did not have a final SER. And

1 it has to do with the environmentally assisted fatigue
2 calculations.
3 I would just summarize very briefly what
4 has happened since. Entergy has chosen to address
5 environmentally assisted fatigue by demonstrating that
6 CUF and the most sensitive locations would remain
7 below one throughout the period of extended operation
8 considering both mechanical and environmental effects.
9 The analysis performed by the licensee are
10 supported also by assumptions that will be monitored
11 and verified during the period of extended operation.
12 The analysis performed by the licensee had
13 confirmed that in all locations CUF is going to be
14 below one throughout the period of extended operation.
15 This staff however has challenged the use of the
16 simplified methodology used by the licensee for those
17 locations which exhibit geometric discontinuities or
18 no symmetric loads such as the feedwater nozzle for
19 example or the circulation out that nozzle and the
20 coarse spray line nozzle.
21 At the request of the staff the licensee
22 has performed an analysis for the limiting location
23 which is the feedwater nozzle, using the methodology
24 at our command which is using ASME code Section 3.
25 The analysis has confirmed that CUF will be below one

1 okay through the period of extended operation.
2 However I believe assuming the same environmental
3 multiplier, the result with more analysis show a
4 higher value of CUF though below one. And so the
5 staff has requested the licensee to perform also the
6 corresponding analysis for the two additional cases
7 where there are geometric discontinuities or no
8 symmetric loads and essentially the locations are the
9 circulation outlet nozzle and the coarse spray line
10 nozzle.
11 Today I believe the licensee wants to
12 present their methodology and make the case for the
13 analysis they performed originally. I believe the
14 issue so far as the SER is closed in the sense that
15 they have committed to perform the two additional
16 analyses as requested by the staff.
17 But we will hear both from the licensee
18 and the staff about this contention and it's an
19 important issue because it may affect other licensees
20 that have performed calculations before using the same
21 methodology used by Vermont Yankee.
22 We would like to introduce and turn over
23 to PT Kuo.
24 MR. KUO: Thank you, Bonaca.
25 Yes, this is indeed the last issue for the

1 Vermont Yankee license renewal application review.

2 It has taken a long time, longer than what

3 we would like to, but I think at this point we believe

4 that the applicant has done what we have asked for,

5 and we are satisfied with what they have done.

6 We have supplemented our SER with our

7 writeup. It's just I believe a week or so ago. And

8 sent it to the committee members.

9 I believe that right now with the

10 additional calculations the applicant has done we

11 consider this issue is resolved, and the applicant

12 will first give you the story of how it is resolved,

13 and the staff will also give you the reason, the basis

14 of why we think this is acceptable.

15 Thank you.

16 With that, applicant, please, take over.

17 MR. DREYFUSS: Good morning.

18 Thank you, Dr. Bonaca, Mr. Chairman,

19 members of the committee.

20 My name is John Dreyfuss. I'm the

21 director of nuclear safety assurance for Vermont

22 Yankee.

23 Before we get going with the presentation

24 I do want to make sure that we introduce our Vermont

25 Yankee and Entergy team here.

1 First, I'd like to recognize Ted Sullivan,
2 our site vice president.
3 MR. SULLIVAN: Good morning. I'd like to
4 thank the committee for allowing us to be here today
5 to continue the discussion on our license renewal
6 application. And I'd like the team to identify
7 themselves, and then we'll turn it back over to John.
8 John's our lead spokesperson.
9 MR. MANNAI: David Mannai, licensing
10 manager, Vermont Yankee.
11 MR. RADEMACHER: Norm Rademacher,
12 engineering director.
13 MR. FITZPATRICK: Jim FitzPatrick, design
14 engineer.
15 MR. STEVENS: Gary Stevens, structural
16 integrity associates, consultant to Entergy.
17 MR. GOODWIN: Scott Goodwin, design
18 engineer.
19 MR. METELL: Mike Metell, license renewal,
20 project manager.
21 MR. YOUNG: Garry Young, manager of license
22 renewal for the Entergy fleet.
23 MR. COX: Alan Cox, technical manager,
24 license renewal.
25 MR. LOCK: Dave Lock, I'm part of the

1 Entergy license renewal team.

2 MR. DREYFUSS: All right, very good. Good

3 morning.

4 Next slide, Beth, please.

5 For the agenda for today we will go

6 through the environmentally assisted fatigue. And we

7 do recognize the last time we were here we went

8 through the rest of the SER and application and talked

9 about a lot of different issues.

10 Our focus here on our presentation is as

11 requested on the fatigue issue.

12 So we'll go through an overview of that,

13 some of the timeline, how we got to this point. We'll

14 talk about some of the bases, and go through both the

15 evaluation that we performed where there were

16 challenges from the staff, and confirmatory analysis.

17 And just from a nomenclature standpoint,

18 I did want to mention, a number of different terms

19 have been tossed out. What we will refer to during

20 the course of our presentation, we had original

21 analyses, for the license renewal we performed re-

22 analysis. I think we referred to that in the SER; you

23 may have seen the simplified analysis. So we've

24 called it a re-analysis.

25 And then the confirmatory analysis that we

1 did I think is also referred to variously as the
2 updated analysis. So for us re-analysis and
3 confirmatory and we'll step through that as we go
4 through the presentation.
5 I think the key thing to talk about is
6 that for the license renewal the confirmatory analysis
7 that we performed for the feedwater nozzle is the
8 calculation of record for license renewal.
9 Additionally we'll talk about the license
10 condition. We do have a license condition where we
11 will perform calculations, confirmatory calculations,
12 for the remaining two nozzles that were the subject of
13 the challenges, and we will perform those calculations
14 prior to two years prior to entering into the extended
15 period of operations.
16 Next slide.
17 From an overview standpoint we did, as far
18 as the full scope of environmentally assisted fatigue,
19 we did the locations that are identified in the
20 governing NUREG 6260, and that was the focus and the
21 basis for the calculations that we did do.
22 Our original piping was designed to the
23 B31167 code so therefore we did not have the
24 calculations. That is what drove why we had to do
25 these calculations.

1 From a timeline standpoint in September we
2 completed the re-analysis as well as all the rest of
3 the work that we did on environmentally assisted
4 fatigue. There was an audit by the staff of those
5 calculations in October. And really during the course
6 of that timeframe, from October through January of
7 2008, a lot of questions back and forth, and a number
8 of different RAIs and audits that were performed
9 questioning the approach that we had taken.
10 And the key challenge was how we treated
11 stresses at the blend radius for these three
12 particular nozzles, coarse spray, reactor recirc and
13 feedwater.
14 So what we'll do during the course of the
15 presentation is, we'll talk about what we did on that
16 reanalysis, and provide you with the basis for that.
17 We will also talk about what we did on the
18 confirmatory analysis as well.
19 We did complete - we had requested a
20 public meeting. And that public meeting was held on
21 January 8th, where we defined what approach we took
22 with the reanalysis method. At that meeting we also
23 said that we were working on a confirmatory analysis
24 for the feedwater nozzle.
25 We did complete that analysis on the

1 nozzle and submitted that on February 14th - I'm
2 sorry, January 30th, Ray. And NRC, Dr. Chang, did an
3 audit of that calculation on Valentine's Day of 2008.
4 We also submitted an amendment that
5 provided some chemistry data. That was one of the key
6 questions on how we treated the chemistry effects, and
7 how it may have influenced environmentally assisted
8 fatigue.
9 So as far as basis for the evaluation, we
10 are consistent in our approach, consistent with the
11 Gall report. We did evaluate the specified locations
12 as I mentioned in the NUREG 6260, and the Fen
13 methodology that we used was appropriate and was
14 driven by the two cited NUREGs there for the different
15 materials, carbon steel and stainless.
16 Additionally we did use our as-built
17 drawings to do our analyses. We used the design.
18 MEMBER ABDEL-KHALIK: How different are the
19 as-built drawings from the design drawings?
20 MR. FITZPATRICK: There is additional
21 thickness for - this is Jim FitzPatrick - the shell
22 has additional thickness in it from the design for
23 rolling, like a quarter inch, and the nozzles have a
24 little additional thickness from the original design
25 provided on the fabrication drawings.

1 MEMBER ABDEL-KHALIK: And when were those
2 as-built dimensions acquired?
3 MR. FITZPATRICK: They are on the GE
4 drawings of the design before the plant started up.
5 MEMBER ABDEL-KHALIK: Thank you.
6 MR. DREYFUSS: We did use design transients
7 versus the actual transients, so did not take credit
8 for any - we used the conservatisms associated with
9 design transients.
10 We'll talk a little bit more about cycle
11 projections, but we did project cycles for 60 years.
12 We'll talk about some conservatisms that we have
13 inherent in those projections as well.
14 We also assumed -
15 CHAIRMAN SHACK: So when you say design
16 versus accident transient severity, it means you are
17 using the stresses from the design transient, not the
18 numbers of the design transient?
19 (Simultaneous speakers)
20 MR. DREYFUSS: And again we did assume full
21 uprate conditions for the 60-year period. We did do
22 the uprate in 2006.
23 MEMBER ARMIJO: From day zero uprated
24 conditions, and put those into all of these analyses?
25 MR. DREYFUSS: That's correct. Assume from

1 1972 up to this point and through the 60-year period.

2 Now we are going to talk about the

3 specifics of the evaluation itself, and Jim do you

4 want to talk on this a bit.

5 MR. FITZPATRICK: We used existing design

6 analysis for the RPB shell, the lower head, the

7 recirculant nozzles, and by the FEM to those existing

8 analysis, and for the fatigue analysis MB 3200 rules,

9 for three nozzles that entire original design fatigue

10 usage, we analyzed for new models, new analysis, for

11 the feedwater recirc outlet nozzles and the coarse

12 spray nozzles.

13 MEMBER ARMIJO: Was the feedwater inlet

14 temperature changed as a result of the uprate?

15 MR. FITZPATRICK: 372 to 392.

16 MEMBER ARMIJO: Now is that change in the

17 conservative direction as far as this analysis is

18 concerned?

19 MR. FITZPATRICK: It increases the stress

20 range from your normal operating down to your

21 injection. Delta T goes from, instead of 372 to 100,

22 it goes from 392 or 394 to 100. It's a small increase

23 in range.

24 MEMBER ARMIJO: Okay, thank you.

25 MR. FITZPATRICK: And then for the piping

1 we performed new ASME class I fatigue analysis for the
2 recirc RHR.
3 On the reanalysis of the three nozzles, we
4 used 60-year cycles projected based on design
5 transient severity and the cycle. So basically
6 reviewed our design spec, and updated BWR for thermal
7 cycle definitions.
8 We had new answers, find out what models
9 are developed for these three nozzles using the as-
10 built drawings and the material specs for each one of
11 these nozzles.
12 Heat transfer coefficients were based on
13 the design report and design specifications.
14 A thermal stress response in the
15 reanalysis was developed from a step change in the
16 temperature. And Green's function was developed from
17 that.
18 Using the Green's function we developed
19 thermal transients, stresses, for each set of the
20 design transients for each nozzle.
21 And we calculated component stress
22 differences. This is where the difference between -
23 we'll explain a little further on, but this is where -
24
25 CHAIRMAN SHACK: Let me just come back to

1 your Green's function. So you got your Green's
2 function essentially from a finite element analysis -
3 MR. FITZPATRICK: Yes.
4 CHAIRMAN SHACK: - with a step transient.
5 MR. FITZPATRICK: Yes, sir. And you pull
6 component stresses from there versus - it calculates
7 stress intensity. And that has led to some confusion
8 before.
9 Taking those, the thermal stresses, the
10 pressure stress intensities were directly from the
11 answers found with the models, and they were factored
12 to account for the actual pressure during the
13 transients, the unit load case and then factored up
14 for that.
15 Adjusting intensities to detached piping
16 loads were conservatively calculated and added to the
17 other stress intensities for each transient and each
18 temperature.
19 The maximum stress differences from the
20 temperature transients were combined directly with the
21 stress intensities from the pressure stresses, and the
22 detached piping loads.
23 And the ASME MB 3200 fatigue calculations
24 performed on the collective thermal transient stress
25 systems.

1 And that gets rid of the ASME CUI. Then
2 we used a bounding fatigue life correction factor for
3 all the transients, one bounding number applied to
4 that CUF for the entire 60-year operating period.
5 And then the environmental CUF is that
6 bounding factor times the CUF.
7 We had a list of -
8 CHAIRMAN SHACK: One other - every time I
9 read the analysis it says, axi-symmetric ANSYS model.
10 This is a nozzle on a cylindrical shell. Why is it
11 axi-symmetric?
12 MR. STEVENS: It's a simplification to -
13 obviously when you model a nozzle axi-symmetric you
14 treat, the vessel then becomes a sphere. So we also
15 had to apply a correction factor to account for the
16 ovalization of two intersecting cylinders.
17 And that's just a traditional way of
18 industry way of modeling these nozzles.
19 MR. FITZPATRICK: Did that answer your
20 question?
21 Some of the conservatisms in the analyses,
22 the major ones -
23 MEMBER ARMIJO: Just before you go on, the
24 bounding fatigue life correction factor, you say you
25 calculated from water chemistry conditions expected to

occur over the 60-year operating period. But you have had major changes with the water chemistry with hydrogen implemented many years after. So which is the water chemistry you used? Did you use the appropriate water chemistry for the normal water chemistry period, and a different water chemistry correction? Or the hydrogen water chemistry period?

MR. FITZPATRICK: Did both, and Gary can give you a detail on that.

MR. STEVENS: We actually broke the operating history up into three parts. The prior to hydrogen water chemistry, or normal water chemistry, where the factors, at least for the carbon and low alloy would be much higher and the oxygen content was higher.

Then we had the operation that was post hydrogen water chemistry implementation, with the historical duty if you will or availability of the system.

And then in the future and what that's projected to be. And that was based on water chemistry guidelines that the plants are following.

CHAIRMAN SHACK: And you used bounding strain rates for all these transients? Or you actually tried to estimate strain rates?

1 MR. STEVENS: We used bounding strain rates
2 for everything.
3 MR. DREYFUSS: And we will talk a little
4 bit more about chemistry during the course of the
5 presentation.
6 MR. FITZPATRICK: Some of the major
7 conservatisms in the nozzle reanalysis. The number of
8 transient cycles using analysis was greater than the
9 expected number of cycles for 60 years based on our
10 plant experience. For example, heat up and cool down,
11 there were 300 cycles - heat up cool down for the
12 feedwater nozzle includes heat up and then a turbine
13 roll. It's basically the major transient. We used
14 300 cycles of that. To date we've had 95 over 36
15 years of operation, and the original design was 200;
16 we don't even expect to hit that number, based on the
17 past history of 20 years of operation.
18 But the plant had more transients in the
19 beginning than they do in later life.
20 The transient severity is a conservatism
21 versus using actual transients. We used the bounding
22 values, the pressure and temperature of the EPU for
23 the entire life, and the bounding Fen multiplier. We
24 used values, the input stat, the temperature strain
25 rate, the sulfur content were chosen to maximize that.

1 And that multiplier was basically applied
2 to all transient stresses, and that was the reanalysis
3 method that we used.
4 MR. DREYFUSS: We talked about the
5 chemistry itself. Bottom line is we chose our
6 chemistry factors conservatively, and chemistry
7 effects have been conservatively factored into the
8 analysis that we did.
9 We did use the Fen factors from the cited
10 NUREGs. Additionally we selected the various
11 parameters that you see here in such a way as to
12 maximize the effects and maximize the contribution
13 that they had in terms of their effect on the
14 environmental factors.
15 So strain rates, temperatures, dissolved
16 oxygen, were all factored in that way.
17 CHAIRMAN SHACK: Of course there is no
18 conservatism in that sulfur number since your sulfur
19 probably is well over .015. In the materials you
20 actually have in the plant.
21 MR. DREYFUSS: Correct.
22 MR. STEVENS: Plus that particular
23 parameter tends to have less effect on the relations
24 than some of these, oxygen and temperature and strain
25 rate for example.

1 MEMBER ABDEL-KHALIK: Well, typically, how
2 long would these oxygen excursions last?
3 MR. FITZPATRICK: A couple of days when
4 there's the heating up, and you do a cycle flush, and
5 then you start heating the reactor up, conduits come
6 online. It takes awhile to get to the steady state on
7 the chemistry.
8 MR. DREYFUSS: The startup might be over an
9 18-hour period, but getting it back to a stable
10 condition will sometime take a day or two.
11 MEMBER ABDEL-KHALIK: So the different
12 between the value that you used and the analysis,
13 which is the mean plus one standard deviation, the
14 difference between that value and the nominal value
15 for dissolved oxygen, what would that be in
16 percentage?
17 MR. FITZPATRICK: It's a little different.
18 That number could be significantly higher, but there's
19 no transient occurring at that time. So looking at 60
20 years we tried to do a bounding number, a
21 representative number for all the transients expected
22 to occur over 60 years.
23 MR. CHANG: If I may interject something.
24 The staff did a focused review of what they did,
25 especially in the oxygen content and excursion.

1 Now this is a BWR, not a PWR. The PWR,
2 the maximum transients for the most critical
3 components is during the heat up and cool down. The
4 PWI especially the feedwater nozzle - now excursion of
5 the oxygen content occurred during the heat up, but at
6 that time there are no significant transients. So
7 even excursion rate is high, applied to - if you apply
8 to zero it's still zero. I don't mean zero; I mean
9 small number.
10 MEMBER ARMIJO: So these excursions, these
11 oxygen excursions, really had a very small
12 contribution to the number that you used for the Fen?
13 MR. DREYFUSS: Right, it did not
14 significantly impact it.
15 So the summary here is that the cumulative
16 usage factors at Vermont Yankee under all analyses
17 that we did perform do remain below one for the full
18 60 years of extended operation with margin.
19 I'll talk a little bit about the audit
20 that NRC performed of the calculations. And the key
21 challenges really were when we had done the analysis,
22 we did the feedwater coarse spray and reactive recirc
23 nozzle corners. The challenges were at the nozzle
24 corners, the blend radius as it's referred to as well.
25 And the methodology by which we treated

1 the stresses was really the key factor as Jim had
2 talked about as well. So we used component stresses,
3 stress difference versus the maximum stress
4 intensities. And what it comes down to is the
5 treatment of sheer stress and are you neglecting sheer
6 stress using this methodology.
7 That was the challenge. So we did submit
8 this amendment 33, based on or in response to an RAI.
9 And we documented the evaluation that we had performed
10 and the methodology by which we had treated the
11 stresses versus the component stress difference.
12 And we did essentially a sensitivity calc
13 that resulted in a change, a maximum difference
14 between the reanalysis that we had performed and the
15 sensitivity that resulted in a very small maximum
16 change, a .003 change which I think would have been
17 complete at that point. But we really only addressed
18 one element of the challenge.
19 And Gary, if you would explain a little
20 bit about that.
21 MR. STEVENS: Yes, I think what we really
22 addressed in that response was the effect of sheer
23 stress.
24 Another part of the challenge was on this,
25 it's been coined in several different ways, uni-axial

1 stress, one-D virtual stress. And I think what I'd
2 prefer to do is, we have a slide coming up where we
3 show the analyses we did side by side, and I can get
4 into a little more detail on that one.
5 But for the purposes of this slide, I
6 think we generally agree that we might have satisfied
7 the sheer stress issue, but we didn't satisfy the uni-
8 axial or one-D virtual stress issue. And we'll talk
9 about that in a few more slides.
10 MR. DREYFUSS: And Jim, if you could step
11 us through the approach that we did here on the
12 confirmatory calculation.
13 MR. FITZPATRICK: We did a confirmatory
14 calculation on one nozzle, a feedwater nozzle. It's
15 the controlling nozzle, because it is the most severe
16 in design transients; had the highest fatigue uses of
17 the three nozzles in question.
18 And we tried to put this, in simple terms,
19 basically it's cold return water and is the hot
20 vessel. That's why it is the more severe - the most
21 limiting nozzle.
22 A number of design transients at two to
23 three times the number of transients for the other
24 nozzles. All the injections occur at that nozzle,
25 versus the other ones feeling just the environment in

1 the vessel.

2 And industry experience has shown that the

3 fatigue usage is typically higher at the fatigue - at

4 the feedwater nozzle than any other nozzles.

5 We used the same ANSYS finite element

6 model, the same transients, the same cycles, and the

7 same water chemistry that is the previous nozzle

8 reanalysis.

9 And the confirmatory analysis, you combine

10 six stress components for NB-32, 16.2. The sheer

11 stresses are included for each stress.

12 And as the fatigue analysis was done for

13 NB-32 2.4 for all the stress pairs, and this is the

14 same methodology used in the reanalysis.

15 CHAIRMAN SHACK: What is the difference

16 between the confirmatory calculation and the

17 reanalysis?

18 MR. DREYFUSS: We are going to show that on

19 a slide. I make that very clear.

20 CHAIRMAN SHACK: Not the difference in the

21 results. What's the difference in assumptions?

22 MR. STEVENS: Should we go to that slide

23 now? So this slide has the two analyses in parallel,

24 the reanalysis, and the confirmatory calculation.

25 And what's in bold we'll talk about is

1 going to answer your question on what the differences
2 are.
3 And I don't mean to simplify this
4 calculation, and this analysis; it's done in six
5 steps. We've simplified into six boxes, which in no
6 way indicates that there are six simple steps to this.
7 It's an ASME code analysis, and there is a lot of
8 rigorous detail built into this.
9 So let's start at the left, and we'll kind
10 of go through these both in parallel. Because you'll
11 see a lot of the boxes are identical.
12 On the left we have 60-year cycles in
13 design transients. That was the same and identical
14 for both analyses. We assumed the same transients and
15 the same quantity; we didn't differ on those.
16 We built an ANSYS finite element model.
17 It was the same for both analyses. There was no
18 different in model at all.
19 The model how we used it was, and the
20 stresses we obtained, is where it was different, and
21 that's the next one. So for in both analyses we'll
22 take the simple part first, pressure stresses and
23 piping stresses - pressure stresses were determined
24 from that finite element model, pressure stress
25 intensity, and piping stresses were done by hand.

1 That was identical for both.

2 Now let's go to the first box, and here's
3 where we have the first difference. In the first
4 analysis rather than run all the transients, and we
5 have approximately 20 transients in the feedwater
6 nozzle - there's many and they are complicated -
7 rather than run all of those individually through the
8 finite element model, we used a Green's function to
9 generate the stress history for those transients.

10 That's - the Green's function is a well
11 known technique in most all college mathematical
12 textbooks. I don't think there is any controversy in
13 how the Green's function generates stresses. But
14 we'll talk about this uni-axial or one-D stress in a
15 minute, and that's really where the contention lies
16 there.

17 But in the first case, the reanalysis, we
18 used the Green's function to generate stress histories
19 for all those transients. That takes a significantly
20 less effort than running all those transients through
21 the finite element model.

22 CHAIRMAN SHACK: But this is purely an
23 elastic problem, right?

24 MR. STEVENS: That's correct, so Green's
25 functions would be appropriate for that. Everything

1 is linear.

2 Now in the second case, the confirmatory
3 calculation, we ran everything, all the transients
4 individually through the ANSYS finite element model.
5 So up to now the only difference is, we used a Green's
6 function in the first case to generate stress
7 histories; in the second case the ANSYS finite element
8 model.

9 To your point the two should be identical,
10 because everything is linear.

11 So how did we combine - moving on to the
12 fourth box - how did we combine and determine maximum
13 stress intensities? Here is where we get into some
14 esoteric differences between the two.

15 I'll take the easy one first, which is the
16 lower one, the confirmatory calculation. We basically
17 take for all those transients, we get six stress
18 components out of the finite element program, X, Y, Z
19 and three shears. And we combine those for NB 32 16.2
20 of the code, which for every peak and valley you take
21 differences, in those six stress components, and you
22 rotate those into principal stress differences, and
23 it's stress intensity. And you use that history,
24 resultant history, to calculate fatigue usage.

25 What did we do with the Green's function?

1 We'll move up to the reanalysis. The Green's
2 function, what we did there is, the Green's function
3 itself, the stress history we got out of the finite
4 element program, we could have had six Green's
5 functions to use to generate six stress histories, six
6 component stress histories for all the transients.
7 What we took out of the finite element
8 program was basically the maximum stress difference,
9 which is essentially equal to the stress intensity
10 from the finite element program.
11 So what we got from the Green's function
12 was a stress intensity history, and we used that to
13 integrate and come up with a stress intensity history
14 for all of the transients. So I think you can see
15 that the simplification here that was made, and there
16 are several, we are obviously by using the maximum
17 stress component difference we are ignoring sheer
18 stresses.
19 And in some of the responses to the RAIs,
20 and John mentioned on the one slide we showed the
21 sheer stresses were negligible.
22 But the other issue that we didn't address
23 in those RAIs is taking a single stress intensity
24 history and using that through a Green's function to
25 generate a stress intensity history for all these

1 transients.

2 Is that identical or proximate or close to

3 taking all the six stress component histories and

4 doing differences and rotations into a stress

5 intensity difference? I think there is where the

6 difference and the contention really lay was that

7 approximation.

8 Both of these analyses, the intent is to

9 do an ASME code fatigue calculation. There was never

10 any intent not to do so.

11 The difference in that step I think is

12 really key to our differences. And obviously doing a

13 confirmatory calculation was intended to resolve that

14 issue, proof that how close these were.

15 So after that step then we have a stress

16 intensity history that was computed differently in

17 each of the techniques. But given that stress

18 intensity history, the fatigue usage analysis was

19 performed identically between the two.

20 There is a type on the slide here. It's

21 not NB 32 24, it's 32 22.4.

22 MR. RADEMACHER: So that is 32 22.24?

23 MR. STEVENS: Correct. So that step is

24 identical between the two. And then the last step is

25 - we get a fatigue usage out of that fifth box that we

1 then apply environmental factors to.

2 In the reanalysis, the first one we did,

3 the maximum Fen was applied to the total usage, to

4 come up with the environmentally assisted fatigue

5 number.

6 In the confirmatory calculation a maximum

7 Fen was computed for each load there, where the only

8 thing that was taken into account was the temperature.

9 We took the maximum temperature of each load, put the

10 strain rate and the sulfur and all the other primaries

11 were the same. And good or bad the intention of that

12 difference there was to demonstrate yet another

13 conservatism built into the analysis.

14 So the only thing different in the last

15 step, which is the environmental fatigue evaluation,

16 was one Fen applied to total usage in the reanalysis;

17 multiple bounding Fens applied to each load pair in

18 the confirmatory calculation.

19 MEMBER ARMIJO: So the more conservative

20 treatment was in the reanalysis?

21 MR. STEVENS: For that step.

22 MEMBER ABDEL-KHALIK: How much do the

23 material properties change over the temperature range

24 let's say for the feedwater?

25 MR. STEVENS: I can't give you a specific

1 answer, but generally speaking there could be 10 to 15
2 percent variation I the material properties over the
3 range of temperatures we are looking at.
4 MEMBER ABDEL-KHALIK: And how is that
5 accounted for in the analysis?
6 MR. STEVENS: In the reananalysis we picked
7 bounding temperature properties. Because of the
8 Green's function use, everything - you do one run and
9 everything is constant. So we tend to take the
10 bounding material properties and heat transfer
11 coefficients.
12 In the confirmatory calculation the
13 material properties are varied with temperature input
14 to the finite element program as well as heat transfer
15 coefficients.
16 And you are really touching on one key
17 element here, if you take these - we have identified
18 really just three bold spots where these analyses are
19 different. We identified on an engineering level 20
20 differences in these two analyses, things like you
21 just mentioned, material properties; they were treated
22 differently. Heat transfer coefficients were treated
23 differently. Twenty differences between the
24 reanalysis and the confirmatory calculation really
25 that were levels of conservatisms built in to the

1 analysis, approximations using a simplified approach
2 versus a very detailed approach.
3 So we did not go through exhaustively a
4 parametric study to understand which of those 20 items
5 caused the differences between the two. We were
6 satisfied at the end that the final result we got was
7 the same, usage factor less than one with margin.
8 MR. DREYFUSS: Do you want to move on to
9 the results?
10 MR. CHANG: Before moving on, could I put
11 in a couple of comments?
12 I think Gary have summarized what you call
13 the reanalysis and what you call the confirmatory
14 analysis very nicely.
15 But I'd like to bring out a couple of key
16 points that can facilitate going right through the
17 heart of the issue.
18 Actually applicant submitted two
19 reanalyses. One was submitted by amendment 31 which
20 is dated 9/17. The second refined analysis was
21 submitted December 11th; that was submitted by
22 amendment 33.
23 So those two I call them just reanalysis.
24 And then there is a final confirmatory - you call
25 final confirmatory analysis submitted by amendment 34

1 on January 30, '08.

2 Now in our final SER, submitted to the

3 ACIS and it was issues, we call that analysis as

4 analysis of record for the feedwater nozzles. Why?

5 That's the point I'd like to point out. Missing this

6 phase, this is the opportunity, you may keep in mind,

7 reanalysis, analysis of record, which is not the case.

8 The - now let's call that analysis of

9 record. The analysis of record took all the unknowns

10 out of the place. You use six components, stress,

11 including sheer stress and nominal stress. Only thing

12 is you approximate the header effects by a spherical

13 header. That as Gary said is a very standard

14 industrial approach. We buy that.

15 The difference comes that the reanalysis

16 did not analyze every transient. From the base

17 transient case, and finite element results, from that

18 base case you project it to the other transient

19 stresses by the Green's function.

20 I don't dispute the Green's function

21 methodology at all; I love it. The only way is, how

22 do you apply it? Now you apply it by six components,

23 or you apply it by one-D virtual stress.

24 The reanalysis still have the one-D

25 virtual stress there. But the analysis of record do

1 not have that.

2 So let's for the time being call the

3 analysis of record close to the reality. The outcome,

4 you don't see it at the amendment 34. Because

5 amendment 34 seems to indicate the analysis of record

6 always give you a lower answer. That means the

7 reference analysis is conservative.

8 But that is deceiving, because if you use

9 the same Fen as you used in the refined analysis, the

10 CUF will be higher. As I report it, as the staff

11 report it in the final SER, that number, the CUF, will

12 be .893. It's not .353 anymore.

13 So in other words the analysis of record

14 gives you higher CUF for everything the same

15 condition.

16 In other words the refined analysis can be

17 conservative, can be not conservative; can be

18 conservative by a factor of two; and also can

19 underpredict by a factor of two.

20 For that reason we don't call that the

21 refined analysis or analysis of record. But for

22 Vermont Yankee the feedwater nozzle, the final

23 analysis, additional analysis, or whatever you call

24 it, still give you at least 10 percent margin to the

25 code CUF limits.

1 For that reason I feel comfortable. Now
2 as long as you make this as the analysis of record.
3 For the future if you want to adjust anything you base
4 it on that. You don't back to the refined analysis.
5 On the same basis if this can produce
6 results like this, the same or similar results can
7 also be produced. I'm not sure, because I didn't do
8 that analysis on the other two nozzles.
9 For that reason we asked them to perform
10 similar analysis for the other two nozzles. When all
11 this is completed, we have three analyses of record.
12 Those are fully justified.
13 VICE CHAIRMAN BONACA: What I would like to
14 point out, however, is that this calculation results
15 seems to be consistent with the one that was in the
16 SER. So we would like to understand it better.
17 In the SER you asked the licensee to use
18 the same maximum Fen.
19 MR. KUO: Right, what we consider that is
20 acceptable is what the applicant calls confirmatory
21 analysis.
22 VICE CHAIRMAN BONACA: Yes, but here in the
23 confirmatory analysis I see the result being 0.35, and
24 you are quoting .893.
25 MR. CHANG: Eight nine three, we have both

1 numbers reported in the SER, so it's on record that
2 the analysis of record, using the maximum Fen, you
3 will get .893. But you use 24 different values of Fen
4 which is appropriate, you will get .353.
5 In other words, the .353 is not wrong;
6 it's just compare the earlier analysis and the newer
7 analysis. The earlier analysis may not be
8 conservative. It depends on the final analysis which
9 we know is right and conservative.
10 CHAIRMAN SHACK: What you are arguing is
11 that his stress analysis could be nonconservative, and
12 he covers that up by using a conservative Fen, but
13 clearly his overall calculation is conservative but
14 he's piling it up in different ways, and I guess the
15 question is, is that always going to be the case?
16 It's certainly true in these two situations.
17 MR. CHANG: Normally staff do not second
18 guess what the future outcome will be. But since this
19 feedwater nozzle, the CUF, is five to 10 times higher
20 as compared to the others, I would imagine the other
21 two nozzles when you complete your analysis give us a
22 good foundation to work for the future. This number
23 will also be good.
24 MEMBER ARMIJO: I'm a little confused. The
25 mechanical analysis I think, the confirmatory

1 calculations were done by the methods the staff was
2 comfortable with and were done with a lot of
3 conservatism as pointed out in some of these charts.
4 In addition they applied a more realistic
5 Fen for different periods as opposed to the original
6 reanalysis approach. But still conservative.
7 So I don't know, and there's a big
8 difference in CUF, right, .35 versus .89, that's a
9 very big difference. So what does the staff consider
10 to be the official number for CUF for this nozzle?
11 MR. CHANG: .353.
12 MEMBER ARMIJO: Okay.
13 VICE CHAIRMAN BONACA: Because in the SER
14 you state very clearly that any request of the
15 licensee to use a maximum Fen, and you got the value
16 of .89, okay, still using the confirmatory calculation
17 now it ends out to .89, and you are saying because it
18 is higher than what you calculated with the reanalysis
19 which was .64, then the analysis of record has to be
20 the one with the higher value.
21 So here we are talking about apples and
22 oranges. I mean I'm trying to understand what is the
23 confirmatory calculation result, and what is the basis
24 for forcing them to use the highest Fen? I mean
25 that's probably the best question.

1 MR. CHANG: As many people call the fatigue
2 analysis, it's a black box. You can turn out
3 different results depending on the level of
4 sophistication that goes in there.
5 The first step we are trying to establish
6 is, is the Green's function methodology or the
7 confirmatory analysis methodology, which is correct.
8 We say the confirmatory analysis
9 methodology is correct. That's the purpose of
10 bringing the .893 up.
11 VICE CHAIRMAN BONACA: But you told me that
12 0.35 in the confirmatory analysis calculation is
13 conservative; that's what you said.
14 MR. CHANG: They are realistic.
15 Realistically speaking, the refined analysis do not
16 have to use Fen equal to 11 to all the transient
17 pairs. If you make every assumption the same,
18 confirmatory analysis will get you lower results.
19 MR. KUO: Just like you said, Dr. Bonaca,
20 comparing this two analyses here is comparing apples
21 and oranges, because the numbers involved are
22 different in terms of Fen.
23 For the reanalysis that they used, okay,
24 they used a bounding Fen value for all transient
25 pairs. But for the confirmatory analysis as they

1 called it they used Fen, maximum Fen for each
2 transient pair.
3 VICE CHAIRMAN BONACA: that is what I
4 understood. And you said you have to assume the same
5 Fen for both methodology if you want to compare
6 results.
7 MR. KUO: If they were to use the same
8 bounding Fen for all transient pairs, using the
9 methodology in the confirmatory analysis, the number
10 would have been .893.
11 VICE CHAIRMAN BONACA: Okay, that's why you
12 are talking about -
13 MR. CHANG: Dr. Bonaca, Robert Schu, who
14 used to be on my staff and is fairly involved on this
15 topic, he may supplement some of the points.
16 VICE CHAIRMAN BONACA: No, I understand
17 now. But go ahead.
18 MR. SCHU: May I say something? Because
19 basically when you are doing the fatigue analysis
20 you've got to calculate the stress. And right now the
21 stress implemented by the applicant is not correct.
22 Compare - it's not adequate, because everybody believe
23 the ANSYS result is adequate. So we asked the
24 applicant to compare their methodology with the ANSYS
25 analysis. The result, there is no way they can match.

1 So from that analysis record point of
2 view, their Green's function, any time they do a
3 Green's function analysis, they've got to redo the
4 traditional ANSYS analysis.
5 And actually the traditional ANSYS
6 analysis will create the correct results and that's
7 NRC accept.
8 MR. CHANG: The traditional ANSYS analysis
9 will create reasonable results. That result could be
10 higher; it could be lower. But that's reasonable.
11 That's correct. That's why we think our - that's will
12 be our future basis.
13 We want something to be correct.
14 MR. DREYFUSS: Garyk if we could summary?
15 MR. STEVENS: Okay, let's forget abou8t the
16 sixth box here, which is the environmental fatigue,
17 and let's look at the fifth box, which is, we've got
18 the stress history. We calculated fatigue. And let's
19 write some numbers down and put everything in
20 perspective.
21 CHAIRMAN SHACK: That is the CUF in error
22 if we just quite at the fifth box.
23 MR. STEVENS: We will compare apples to
24 apples here, which is CUF from each analysis prior to
25 an application of environmental factors.

1 Okay, the top box, the CUF for 60 years
2 from the reanalysis was .064.
3 The bottom analysis, fifth box, the CUF
4 for 60 years was .089. The difference between .025.
5 If we applied the same environmental
6 factor to both fo those numbers, the difference in the
7 magnitude would be identical to comparing those two
8 numbers. So if I decided the environmental factor is
9 11, and I applied them to both, the ratio of the two
10 would be the same.
11 So comparing apples to apples here, the
12 confirmatory calculation, .089 versus the reanalysis
13 of .064, as I mentioned before there were 20 some odd
14 differences built into these two calculations, any one
15 of which could have contributed to that difference.
16 The use of a single stress intensity
17 history could be one. The material properties varying
18 with temperature could be one. The heat transfer
19 coefficients varying. Any of them. We did not do
20 exhaustive analysis to determine which one contributed
21 how much.
22 So I think what the staff is saying is
23 that that increase is what has led them to the license
24 condition for the other two nozzles.
25 MR. CHANG: You are correct.

1 MR. DREYFUSS: This is what took from
2 September or so up to this point, going through this
3 and trying to address staff questions on it.
4 It became clear to us that a simpler
5 approach is to go with the confirmatory approach.
6 That is why we did that for the feedwater nozzle, and
7 we do have that license permission.
8 MR. CHANG: when all the three nozzles were
9 done, the three confirmatory analyses would become
10 three analyses of record; that's important.
11 MR. MANNAI: This is Dave Mannai, licensing
12 manager. I'd like to make one point, because I did
13 sense a little bit of concern on the part of the
14 staff, the ACRS committee. The bottom line is, we
15 agreed with the NRC in their request to make the
16 confirmatory analysis the analysis of record.
17 When we had performed the calculation and
18 then subsequently the NRC staff had ordered that
19 calculation, they looked at our methodology, and they
20 did not disagree with the fact that for the
21 confirmatory analysis that the maximum Fen factors had
22 to be chosen for each transient, but that was a more
23 realistic use of that calculation that was wholly
24 appropriate as Dr. Chang said a month ago.
25 And so if you stop in the middle of it

1 you'd say oh there is this big difference. But as the
2 analysts went through and our own folks reviewed that
3 and then subsequently the NRC staff reviewed it, there
4 were no concerns with the use of that calculation or
5 those assumptions that were used.
6 MEMBER ARMIJO: Okay, so there is no
7 disagreement with the staff on the use of bounding
8 Fens for each transient pair as the right way to go;
9 correct?
10 MR. MANNAI: Right.
11 MR. KUO: It is more realistic. The reason
12 that we want to make this so-called confirmatory
13 analysis as the analysis of record is to prevent
14 future readers getting the wrong impression. The
15 original reanalysis is still the right reanalysis that
16 we accept.
17 MR. CHANG: If you only read this analysis
18 result once, you want to read the right one. You can
19 skip all the intermediate steps.
20 MR. DREYFUSS: Okay, next slide.
21 These are the results, we've talked about
22 them. And the next slide.
23 I'll speak a little bit about the license
24 condition. As discussed, the confirmatory analysis
25 for the feedwater nozzle is complete. It is the calc

1 of record.

2 The reanalyses performed for coarse spray

3 and reactor recirc outlet you can see the CUFs

4 adjusted for environmental factors here. The .17 and

5 .08, we fully anticipate that as we perform the

6 confirmatory calculations, that we will again be below

7 one with plenty of margin, and that in fact the

8 feedwater nozzle is the controlling nozzle for us.

9 The license condition itself is, we will

10 perform the confirmatory analyses for coarse spray and

11 recirc outlet no later than two years prior to going

12 into the extended period of operation.

13 MEMBER ARMIJO: If you are already tooled

14 up for this analysis work, why don't you just do it?

15 MR. DREYFUSS: There is some additional

16 work to do, there's resources, there's modeling work

17 that needs to be done. We will be getting to work on

18 that. We just don't have those analyses complete yet.

19 Our intention is that we will be working

20 on these during the course of this year, and getting

21 that work complete.

22 VICE CHAIRMAN BONACA: Thank you for the

23 presentation. It was clear, and we begin to

24 understand what's happening here. And now we go to

25 the staff presentation, right?

1 MR. ROWLEY: Good morning. My name is
2 Jonathan Rowley, and with me I have Dr. Kenneth Chang.
3 And we will discuss the environmental fatigue issue as
4 it pertains to the Vermont Yankee safety evaluation
5 report.
6 Next slide. I'd like to give you a quick
7 recap of this discussion from the February 7th, HRS
8 meeting. We talked about the resolution of this
9 concern, and the included license renewal, the license
10 condition that we have applied to Vermont Yankee.
11 Next slide.
12 As you can recall Vermont Yankee revised
13 their application to use the fatigue model for their
14 management of fatigue for the extended period of
15 operation. The corrective action element of that
16 program allows them to do a reanalysis of components.
17 They submitted those reanalyses to the NRC that
18 included incorporated environmental fatigue on
19 September 17th, 2007.
20 We performed an audit of those reanalyses
21 on October 9th and 10th. We asked six audit questions
22 during that audit. One was not answered to our
23 satisfaction, so we made that an RAI; we sent that on
24 November 27th, 2007.
25 The response to that RAI came back on

1 December 11, 2007.

2 We had some discussions about this RAI.
3 There were some differences in nomenclature and other
4 things that we couldn't quite work out, so we decided
5 to have a face-to-face meeting on January 8th, which
6 was a public meeting on January 8th, 2008, at that
7 time they agreed to submit a confirmatory analysis of
8 the feedwater nozzle. Next slide.

9 That analysis was to include benchmarking
10 for the Vermont Yankee's feedwater nozzle using axi-
11 symmetric on that element model, taking full care of
12 all stress components of the nozzle using ANSYS code
13 for all defined transients; demonstrated that Vermont
14 Yankee specific benchmarking calculations bound the
15 coarse spray and the recirculation outlet nozzles,
16 calculated fatigue usage factors were done by ASME
17 code Section 3, and they can compare the results to
18 the previous calculations to determine if they were
19 conservative or not. Next slide.

20 On January 30th Vermont Yankee submitted
21 those what we called - a terminology change - updated
22 analysis, which is one and the same with the
23 confirmatory analysis. They proved to us that they
24 used the same parameters, same data, methodology, as
25 agreed upon.

1 And the last slide, what was stated during
2 the January 8th meeting; determined that the CUFs were
3 the safe ends and then rated lower than the previous
4 analysis.
5 Next slide please. Supplemental
6 information was submitted to us on February 5th to
7 demonstrate that the updated feedwater analysis bounds
8 the recirculation outlet nozzle, and it described how
9 the water chemistry effects were accounted into this
10 analysis.
11 Next slide. We performed an audit on
12 February 14th, Valentine's Day, and we discussed the
13 things listed here. And I would like Ken Chang to
14 talk about what we did at that audit.
15 MR. CHANG: I will not follow these slides.
16 Instead I will go through the process of how we
17 performed the audit.
18 The audit, the main purpose to address the
19 concerns expressed during the previous ACIS meeting.
20 So really it's the chemistry, effect of chemistry on
21 this EF analysis.
22 So we spent a good time of the day
23 reviewing the absorbed oxygen content, the strain
24 rate, the temperature, the surface content, those
25 parameters that they used in the confirmatory analysis

1 or the analysis of record.

2 Those parameters were properly used, like

3 the dissolved oxygen is average plus one standard

4 deviation. And then we asked about whether any

5 excursion was there, the excursion happened during the

6 heat up. During the heat up process we found that the

7 feedwater nozzle don't have any significant

8 transients, although it doesn't bound the oxygen level

9 during the heat up, so that doesn't really matter.

10 And we also looking at the strain rate, a

11 low strain rate to bound the value, to bound the Fen

12 value, was used all along.

13 And the temperatures, we assumed using 550

14 degree Fahrenheit for the nozzle, which is also

15 bounding.

16 For the surface content, for stainless

17 steel, surface content is not one of the parameters

18 evaluated by NUREG CR 5704. But for the carbon steel,

19 .015 percent was used to have the maximum impact on

20 the Fen.

21 We also look at how they performed this

22 confirmatory analysis. The confirmatory analysis and

23 the reanalysis use the same model, the axis-symmetric

24 finite element model, for which the branch site is

25 exact. You find the axis of symmetry. You do a

1 revolution around it. But on the header pipe, on the
2 header side, you can only simulate with either the
3 flat plate or with a sphere.
4 Normally people do simulate the header
5 effects by using a spherical header. The right way to
6 do is to use two times the actual radius for the
7 sphere. That way you simulate to accurately predict
8 the pressure stress.
9 For Vermont Yankee there was a model using
10 1.5 radius already done, so I don't dispute that,
11 since they adjust the pressure stress by another
12 factor of 1.33, four thirds. Now four thirds times
13 three halves, that's a factor of two. That is a
14 typical number being used by the ASME stress analysis
15 simulating the 3-D effects.
16 We also look into what Fen value we used.
17 That has been already discussed in quite detail. I
18 really fully endorse them of using 24 training pairs
19 to come up the total CUF, and 24 Fens were calculated,
20 one for each training pair. That is the most
21 complete analysis I've seen so far. I hope we can
22 make this as analysis of the future, as a general
23 case.
24 Now, the - another question was asked
25 during the early meeting was how was film coefficient

1 calculated? The film coefficient was calculated
2 correctly even including the gap between the thermal
3 sleeve and the nozzle wall. They estimated how does
4 the gap open or close, and calculated some film
5 coefficient to simulate inside of thermal sleeve,
6 between the thermal sleeve and the nozzle wall, and
7 after the nozzle wall. So that analysis was quite
8 accurate, and even by today's standards it's still
9 very good.
10 Other transients: the two analyses use the
11 same transients; otherwise you cannot compare.
12 Transients got to be the same. Cycle got to be the
13 same. Same training curves. Same number of cycles
14 was used in the refined analysis and in the
15 confirmatory analysis.
16 External piping loads, here is a little
17 deviation from the traditional MD 3200 analysis as
18 compared to this. Although Vermont Yankee did not
19 apply the external piping loads in a 3-D way, but they
20 calculated a stress intensity based on the external
21 load.
22 And that external load was added, that
23 stress intensity was added, to the stress intensity
24 calculated for the thermal transients. After that
25 stress intensity was calculated add on top, that is

1 known to be conservative.

2 K sub e, ASME code requires elastoplastic

3 cycling penalty factor. In old analysis normally

4 people have K sub e equal to one. We look into it,

5 and for the feedwater nozzle, K sub e the worst

6 combination K sub e equals to 1.115. So in other

7 words this 11.5 percent penalty on that underlying

8 stress before you go into the -- allow the cycle to

9 stress to the allowable cycle curve. That is also

10 appropriate.

11 Young's modulus, ASME curve, the fatigue

12 curve, is based on certain Young's modulus. When you

13 are performing analysis you have to adjust your

14 Young's modulus to the ASME code value. That was done

15 also properly.

16 Six stress components, although it's not

17 a true 3-D analysis, but six components was used. For

18 the thermal transients, those components, in

19 particular the unit stress giving small or big is

20 included in their confirmatory analysis. That is, to

21 us that's acceptable.

22 Seismic loading, seismic is one of the

23 transients. Seismic, you cannot put on the 3-D

24 analysis and put in six components, because you don't

25 even know what it is. However, the seismic loads are

1 small compared to similar transient loads. And
2 seismic loads, when seismic load occurs, the strain
3 rate is high, Fen is low. So by not considering the
4 seismic load in the combination, produce conservative
5 results.
6 Cycles: the two analyses use the same
7 cycles, the same transient cycles. That is
8 appropriate.
9 So based on these descriptions we felt
10 through deeper review and through the cooperation of
11 the applicant, by bringing two suitcases of material
12 into NEI, downtown office, we reviewed there; we are
13 very satisfied.
14 If you can make this as analysis of record
15 for the feedwater nozzle, we say, we have no further
16 questions.
17 On the same basis there are two other
18 nozzles, could result in a similar way. So we say, if
19 you perform this kind of confirmatory analysis as
20 described above, then you heard it twice already. You
21 heard it from the applicant; you heard from me. If
22 you do that kind of analysis for the two additional
23 nozzles, our confidence level also goes up for those
24 two nozzles. So the whole issue will be resolved.
25 Now I really want to thank the applicant

1 for performing this analysis, because this, let me
2 remind you, yesterday we talk about whether on the
3 nozzle, they are one location or two locations or
4 three locations which you need to study.
5 This nozzle, the plan radius is not at the
6 safe end. Yesterday you hear about safe end. You've
7 got to evaluate your pipe to the nozzle well, you've
8 got to evaluate the safe end. You've got to judge
9 whether you have similar sleeve or not. You've got to
10 evaluate the plan radius.
11 It happens to be for this nozzle the plan
12 radius is the highest to CUF location. Did you see
13 that yesterday? I don't. That's why we insist on
14 performing similar analyses for similar kind of
15 conditions and terrains.
16 That concludes my presentation.
17 VICE CHAIRMAN BONACA: Could you go to page
18 nine?
19 MR. CHANG: Page nine?
20 VICE CHAIRMAN BONACA: Here you are talking
21 about previous analysis. Is this the reanalysis?
22 MR. CHANG: Previous analysis means the
23 reanalysis. The September 19 and December 11.
24 VICE CHAIRMAN BONACA: Okay. We got an
25 explanation of what we meant by reanalysis and

1 confirmatory analysis. So the October analysis now is
2 the confirmatory analysis.
3 MR. CHANG: One and the same.
4 VICE CHAIRMAN BONACA: That's what I
5 thought.
6 MR. CHANG: Updated analysis, the
7 confirmatory analysis, and the analysis of record,
8 those three are equal right now.
9 MR. SHUN: I am sorry, Ken, why do you say
10 these three are equal? I thought they are different.
11 Reanalysis is reanalysis; normally reanalysis is -
12 they are not equal.
13 MR. CHANG: What Jonathan call is update
14 analysis, and what applicant call as confirmatory
15 analysis, we call them analysis of record.
16 MR. KUO: I would personally suggest, let's
17 not confuse the issue. We, at least from staff's
18 point of view, we stopped using the term, confirmatory
19 analysis. We have the analysis of record.
20 MR. CHANG: I agree.
21 VICE CHAIRMAN BONACA: Are we disagreeing
22 with the previous statement, that previous analysis
23 means reanalysis?
24 MR. ROWLEY: No.
25 MR. CHANG: For the feedwater nozzle, there

1 is only one analysis of record; that is submitted on
2 January 30, '08.
3 VICE CHAIRMAN BONACA: Still it says, the
4 confirmatory analysis which now has become the
5 analysis of record.
6 MS. FRANOVICH: If I may, this is Ronnie
7 Franovich, the reason that this has been such a strong
8 view by the staff is that we are establishing a new
9 licensing basis for license renewal, and so being very
10 clear on what the licensing basis is for this issue is
11 really important for the future regulation of the
12 facility.
13 I wanted to answer one question by the
14 gentleman, why wouldn't they do the analysis now for
15 the other two locations. The end of the current - the
16 period of extended operations really begins in 2012,
17 and so two years before that would be 2010. So it
18 won't be but for another couple of years th8at we will
19 get that analysis in for the other two locations.
20 Just wanted to clarify that too.
21 MR. ROWLEY: All right, next slide please.
22 Our conclusion is that the feedwater
23 analysis is the analysis of record, as performed in
24 accordance with ASME code Section 3, the coarse spray
25 and the reactor circulation nozzle analysis will be

1 performed according to the fourth condition which is,
2 next slide, that the licensee perform and submit to
3 the NRC for review and approval an ASME code analysis
4 for the reactor circulation and outlet nozzle and the
5 coarse spray nozzle at least two years prior to the
6 extended period of operation. This analysis shall be
7 the analysis of record for these two analyses.
8 VICE CHAIRMAN BONACA: Now on the
9 conclusion on the second bullet, did you say that the
10 CUF was calculated in accordance with ASME code
11 Section 3. But the analysis was also in conformance
12 with the ASME code Section 3?
13 MR. ROWLEY: The entire analysis - the
14 entire updated - well, confirmatory analysis, yes.
15 VICE CHAIRMAN BONACA: Yeah, the claim was
16 made that the original analysis was also conforming to
17 ASME code Section 3.
18 MR. CHANG: to be precise, that should be
19 performed according to the ASME code without using
20 Green's function methodology.
21 VICE CHAIRMAN BONACA: Yes, okay. They
22 stated the same thing. So that is not the
23 distinguishing attribute
24 CHAIRMAN SHACK: Well, just to defend the
25 poor Green's function here for a second, poor Mr.

Green, the Green's function is fine. It's how they combine the stresses after the use the Green's function that is the problem.

MEMBER BLEY: Calling that the Green's function method is not right.

(Simultaneous speakers)

CHAIRMAN SHACK: I did have a question, if I could ask Gary Stevens, this came up.

Does the location of the maximum fatigue usage change when you do the individual transients, decay Fen? You find that the actual location of maximum usage has shifted? You didn't look at that?

MR. STEVENS: We did. I'm trying to figure out the best way to answer your question without confusing the whole room.

The answer would be no, but what location we looked at we built into this going into the analysis. And there were several considerations.

First and foremost would be looking at what the original design analysis tells us about where the high usage location is. And that's an appropriate technique -

CHAIRMAN SHACK: Well, no, when we say high usage location, I mean are we talking nozzle or are we talking finite element location, et cetera.

1 MR. STEVENS: I'm not sure I understand
2 that question.
3 CHAIRMAN SHACK: You get a different usage
4 factor for every finite element in this whole axis-
5 symmetric model, and I'm assuming the number you are
6 quoting here is the highest usage factor for any given
7 element that you are looking at.
8 MR. STEVENS: That's right. We based our
9 selection process on really three things: maximum
10 stress, which is going to give us high usage factor;
11 we also need to look at different materials. Some of
12 these nozzles have stainless steel safe ends and low
13 alloy steel nozzle forgings which have different Fen
14 factors associated with them. And we also have to
15 look at chemistry, as in water chemistry.
16 An example there would be the feedwater
17 nozzle where the incoming feedwater stream, the oxygen
18 content is significantly different than it is in the
19 vessel. So the environmental factor for the safe end
20 would be drastically different than it is for the
21 nozzle forging.
22 All that was built together, and that's
23 why for each of these nozzles we take two locations,
24 the limiting location in the safe end, and the
25 limiting location in the nozzle forging. And that is

1 a composite of all those factors going together, that
2 collectively this gives us - between the two locations
3 we've covered the maximum possible usage factor for
4 the whole component.
5 If I - I would come up with a different
6 conclusion if the chemistry was constant for all
7 locations, the material was constant, I might pick one
8 location in a safe end, in a PWR for example,
9 especially where stratification loading is present,
10 and it drives you back to the safe end.
11 In this situation here, with different
12 materials and different chemistry, we chose to
13 evaluate two locations to bound it.
14 MR. CHANG: Dr. Chang. If I may supplement
15 what Gary says. You vary two locations, but when they
16 say safe end, actually they evaluate three locations
17 in the safe end; the pipe end, the pipe to nozzle
18 weld; and the transition. Consider, next to that
19 transition there is a thermal sleeve which can change
20 temperature diffusion pattern.
21 So one location covers three areas which
22 they did not advertise. I just tried to clarify.
23 MR. ROWLEY: So that ends our presentation
24 unless there are more questions.
25 VICE CHAIRMAN BONACA: Thank you for your

1 presentation. And are there any questions? Or
2 further comments?
3 I guess not, so I'll give it back to you.
4 CHAIRMAN SHACK: Gentlemen, I think we can
5 break for lunch until 1:15. And again I'd like to
6 thank the licensee and the staff for very interesting
7 presentations. It did help clarify an issue that was
8 quite confusing.
9 (Whereupon at 12:04 p.m. the proceeding in
10 the above-entitled matter went off the record to
11 return on the record at 1:15 p.m.)
12 CHAIRMAN SHACK: We can come back into
13 session.
14 Our next topic today are some selected
15 chapters of the SER associated with the ESBWR design
16 certification applications. And Dr. Corradini will
17 lead us through that.
18 MEMBER CORRADINI: Thank you, Mr.
19 Chairman. I'll just give a short reminder to the
20 Members about where we are in this. So the purpose of
21 this portion of the meeting is to review four chapters
22 of the design certification document and the
23 associated SERs that we have talked about in
24 subcommittees. Those chapters of the SERs are
25 chapters 9, 10, 13, and 16, with open items related to

1 the ESBWR design certification. G.E. Hitachi, Nuclear
2 Americas, GEH, which we'll keep on using that. I
3 can't pronounce them all together, is here to start
4 this off. Office of New Reactors, Amy Cubbage will
5 give us an introduction to the folks from GEH, who
6 will provide us presentations about those four
7 chapters.
8 To remind everybody, we had the
9 subcommittee meeting a while back, the week before
10 Thanksgiving. Since then we've had already another
11 meeting on another set of chapters and we're only
12 focusing on these four chapters which we'll go through
13 today, 9, 10, 13, and 16.
14 Other than that. I'll remind everybody
15 that the expectation is we will write a letter from
16 this as an interim letter, our second interim letter
17 back to the staff and to the Commission.
18 Amy?
19 MS. CUBBAGE: Thank you very much. Amy
20 Cubbage, lead project manager for ESBWR design
21 certification. As Mike indicated, we were here back
22 in November briefing these chapters to the
23 Subcommittee. We've chosen to structure our
24 presentations to focus on some of the key question
25 areas that the Subcommittee had. So rather than go

1 back through all the material that we presented, we're
2 going to focus on some of those key topics. G.E.
3 Hitachi will be presenting first today and then
4 followed by the staff.
5 Jim Kinsey from G.E. Hitachi.
6 MR. KINSEY: Again, as Amy mentioned,
7 we're here for a follow-up visit. We made a
8 presentation on these four chapters to the
9 Subcommittee earlier. We've captured the
10 Subcommittee's questions and comments and our focus on
11 the presentation today will be around those topics and
12 I'd like to turn it over to Peter Jordan from our
13 Regulatory Affairs Department to start our discussion.
14 MR. JORDAN: Thank you, Jim. Good
15 afternoon, Mr. Chairman, Members of the Committee. My
16 name is Peter Jordan. I am a lead engineer with
17 Regulatory Affairs on the ESBWR project. As Amy
18 mentioned, we have these four chapters which are
19 scheduled for discussion this afternoon and we do
20 understand we have a limited schedule, so we have
21 admonished our personnel to keep their remarks brief,
22 particularly to allow the Committee to have any
23 dialogue that they wish on these various chapters.
24 The presenters we have this afternoon are
25 starting at my immediate right is Mr. Mike Arcaro,

1 followed by Jack Noonan, Jerry Deaver, and Dan
2 Williamson.
3 As we mentioned, these are the four
4 chapters we intend to have discussion on. I would add
5 at this juncture we do not have a specific
6 presentation on Chapter 13, but we are prepared to
7 discuss any topics that the Committee wishes to have
8 some discussion on.
9 With that I'll start off with Mike Arcaro
10 who will provide some remarks on Chapter 9, the
11 balance of plan and auxiliary system.
12 Mike?
13 MR. ARCARO: Thank you very much. My name
14 is Mike Arcaro. I'm a principal engineer for Balance
15 of Plant Auxiliary Systems for ESBWR. I'll go over a
16 brief overview of Chapter 9 and answer any questions
17 or concerns you have. We also have some topics of
18 interest that came up in the Subcommittee that we'll
19 discuss.
20 Chapter 9, overview of auxiliary systems.
21 It provides a description of the axillary and balance
22 of plant systems required for ESBWR. These support
23 systems incorporate design features that are similar
24 to earlier vintage boiler water reactors with the main
25 difference ESBWR uses passive cooling for the first 72

1 hours, so the systems that were safety related are now
2 nonsafety related or written as systems.
3 Overview. Chapter 9 is broken down into
4 different sections. Section 9-1 is for fuel storage
5 and handling. 9-2 is the water systems. 9-3 is
6 compressed air and gas systems. 9-4 are all the
7 ventilation systems. And in addition to 9-4, control
8 room, habitability is also found in Chapter 6-4 for
9 control room habitability, interfaces with the
10 ventilation system.
11 Section 9-5 is those auxiliary systems
12 associated with fire protection. We also have a fire
13 hazard and analysis in 9-A. Support systems for the
14 diesels will be found Section 9-5 and also lighting
15 and communications.
16 A couple of topics of interest we wanted
17 to discuss today, the first one, hydrogen water
18 chemistry. Hydrogen water chemistry, GEH has made the
19 recommendation to customers that the best way to avoid
20 cracking, IGGCS, is to operate with as much of the
21 reactor in a reducing environment. And that's
22 obtained through noble chemistry and hydrogen water
23 chemistry application. Not all customers have
24 followed GE's recommendations and we do have plants
25 operating for extended periods of time without

1 indications of stress corrosion cracking.

2 The ESBWR uses similar material and

3 process selection as we see with those plants that are

4 operating. ESBWR design is less susceptible through

5 mitigating actions such as improved materials, welds,

6 either avoiding welds, avoiding welds in high-flux

7 areas, allowing accessibility for nondestructive

8 testing.

9 The ESBWR basic design provides provisions

10 for implementing hydrogen water chemistry. The

11 shielding is in place. The space allocation is in

12 place for installing the system. So right now

13 hydrogen water chemistry is an optional design for

14 ESBWR with recommendations that the customers do

15 implement it.

16 The second issue --

17 MEMBER ARMIJO: For a matter of record,

18 and I may not be up to date, but the sources I have on

19 the industry that all ESBWRs in the United States are

20 using hydrogen water chemistry or noble metal chemical

21 additions or some version. All the BWRs in Europe are

22 using some version. Mexico is using it. Taiwan is

23 using it. And with the exception of certain plants in

24 Japan are using hydrogen water chemistry. So the

25 experience based on which we're getting perhaps more

1 favorable IGS in heat performance seems to be
2 predicated on the use of this improved water chemistry
3 and so I'm just still a little puzzled by may be a
4 small handful of your potential clients --
5 MR. JORDAN: Large clients?
6 MEMBER ARMIJO: Deciding well, maybe we
7 don't want to use that. It's clearly an economic
8 decision, but I'm just curious if the information I
9 have is out of date or incorrect?
10 MR. TUCKER: This is Larry Tucker with
11 GEH. Do we want to address this now or after the
12 presentation?
13 MEMBER ARMIJO: Now. I would say if it's
14 short, now.
15 MR. TUCKER: We have Tom Caine here with
16 us today.
17 Tom, could you address the question,
18 please. Identify yourself for the record.
19 MR. CAINE: I'm Tom Caine, Manager of
20 Chemistry and Materials for GEH. To the question, as
21 far as implementation, all of the plants in the U.S.
22 are on hydrogen water chemistry. Most of them also
23 using noble chem.
24 In Europe, I believe none of the German
25 BWRs are on hydrogen water chemistry. Few, if any, of

1 the Swedish and Finnish plants are on hydrogen water
2 chemistry. Really, it's just the plants in Spain and
3 Switzerland who are either doing moderate HWC or noble
4 chem. with HWC.
5 MEMBER BANERJEE: Doesn't Forshmark use
6 hydrogen water chemistry?
7 MR. CAINE: There may be one or two in
8 Sweden, but across the board, most of them are normal
9 water chemistry and have not had major issues with
10 cracking, partly because of the material selections
11 done at that time and because of the geometries,
12 somewhat unique geometries of the licensee plants.
13 In Japan, a fair number, most of the
14 plants are on hydrogen. I wouldn't say that they're
15 necessarily at the right level of hydrogen because of
16 operating dose rate issues and they are still in
17 development activities to figure out the best way to
18 address that long term. They've done a lot of reactor
19 internal replacements, so it's not an urgent issue for
20 them.
21 So there's a fair number that are running
22 on normal R chemistry.
23 MEMBER CORRADINI: Does that help you,
24 Sam, for the moment?
25 MEMBER BANERJEE: Yes.

1 MEMBER CORRADINI: We can return to this.

2 MEMBER BANERJEE: I guess your point will

3 be why don't you --

4 MEMBER ARMIJO: I'm not sure it's a

5 regulatory issue, but it's kind of like the life blood

6 of a plant. And it's the most beneficial chemistry.

7 It's still surprising to me that she just simply says

8 that's the way a BWR should operate and hard wired

9 into your DCD and into your certification. But

10 apparently, there's no regulatory forcing function.

11 MEMBER CORRADINI: I think that's a proper

12 analysis.

13 MEMBER ARMIJO: That's where we are.

14 MEMBER CORRADINI: The other part of the

15 equation is that we're also making strides to improve

16 the durability of the internals too so I think --

17 MEMBER ARMIJO: But you know, you can't

18 solve the problem with just materials or just with

19 water chemistry or just with careful fabrication.

20 You've really got to do belt and suspenders so that

21 this new generation of plants doesn't have chronic,

22 infrequent, but painful cracking experience that we've

23 had in the past. I think it's the combination of good

24 water chemistry, good fabrication, and good materials

25 is your -- is the way you'll keep these plants

1 operating well without spending millions and millions
2 of dollars repairing broken things.
3 And one solution alone, I don't believe
4 will solve the problem.
5 MR. JORDAN: Okay, why don't you continue
6 with the air systems.
7 MR. ARCARO: Okay, the next topic of
8 conversation is instrument air quality and air
9 moisture and contamination. Under Rev. 4 of the DCD
10 we changed the configuration of the instrument air and
11 service air systems. The original configuration had
12 separate service air and instrument air systems and
13 the current configuration, the design enhancement
14 utilizes service air compressors to feed the
15 instrument air system through air dryers. And the
16 question was is there concerns with that.
17 To answer that, the service air
18 compressors are oil-free compressors. They're not the
19 reciprocating type compressors, but the modern oil-
20 free compressors. The instrument air, the service air
21 system is maintained at a cleanliness specification at
22 10 microns which is better than the ISA cleanliness
23 requirement.
24 The instrument air system is maintained at
25 a 3 micron downstream of the air dryers. It's got

1 continuous dew point monitor for moisture. The
2 concern was also that what would happen if you
3 operated extended period of time with the air dryer
4 out of service? And in order to do that, the air
5 dryers are designed for 100 percent capacity. We have
6 two of those. So you would have to have multiple
7 failures to get into a bypass mode where they're
8 bypassing service air around the dryer and that's not
9 a credible event and that wouldn't be how we would be
10 operating the plants.
11 So the current configuration meets the
12 requirements of the URD, Utility Design Manual. It's
13 the configuration that the existing plants are going
14 to and is an enhancement over the original, the
15 original system design.
16 Let's see. The next issue --
17 MEMBER BLEY: I understood everything you
18 said. As long as there's a -- you guys aren't
19 actually operating a plant and so the way you would
20 operate it isn't quite the issue. The people who do
21 operate it sometimes even with that kind of
22 configuration, for one reason or another have opened
23 those bypasses and sometimes have gotten moisture out
24 into the system. That was the concern. And I guess
25 just recording that for now, unless you had something

more to say.

MEMBER STEKAR: Operating experience has shown substantial problems with air dryers, regardless of the air dryer design. And instrument air systems operating for reasonably extended periods with the air dryers bypassed and that's just operating experience from a broad range of different plants, different system designs. It just happens. They're high maintenance, high failure rate complements.

MEMBER BLEY: And often people decide maybe I've got a problem with the dryer, let's just bypass it and see and then they leave it sit. And even though it doesn't sound like it happens, it does and it happens a lot. Well, enough that substantial problems have been seen and they can be tricky operational problems. That was our main point.

MR. ARCARO: I think the design mitigates that having 200 percent dryers by doing continuous moisture monitoring and by doing periodic testing, we test for contamination in the system.

MEMBER STEKAR: Every plant that I've ever looked at and done a risk assessment of has had two 100 percent air dryers and if you look at the fraction of time where both of them are out of service, it's a measurable fraction of time.

1 Everything you say in the design is
2 absolutely true and it applies to essentially every
3 operating plant that I've ever looked at.
4 MEMBER CORRADINI: I think the concern is
5 there. I don't think we can do much more of that on
6 this point. Is that a clear statement?
7 MEMBER BLEY: I think so for now. Maybe
8 this will come up later in some of the other.
9 MEMBER CORRADINI: Keep on going.
10 MR. ARCARO: The third topic was control
11 room habitability issues. I guess two separate topics
12 of discussion. The first is the passive heat sink.
13 Previous plants had safety-related control room
14 ventilation systems to maintain the required
15 temperatures in the control building, in the control
16 room. ESBWR uses a passive heat sink. When power is
17 available we have the recirc. air handling units that
18 maintain the space temperatures. If AC power is lost,
19 the nonsafety-related loads are dissipated and we use
20 passive means to remove the remaining heat loads in
21 the control building.
22 The question came up last time what have
23 we done so far as far as modeling and analysis of the
24 passive heat sink? We have a preliminary calculation.
25 It was done in contained software for the high

1 temperature applications and we used eco. sim. for low
2 temperature. So the question was what conditions have
3 we modeled for the control room heatup analysis?
4 The first condition was zero percent
5 exceedence value. That's the design condition for the
6 control room. That's using 117 degree dry volt
7 temperature. We modeled that condition for the period
8 0 to 2 hours, 2 hours to 72 hours, and then after 72
9 hours. We modeled a second condition for the
10 effective humidity on the control room heat up rate.
11 So on that condition we used 88 degree wet volt
12 temperature and 100 percent humidity and modeled that.
13 We also looked at the winter heat load. The concern
14 or question was what happens during the winter time
15 when you're at -40 degree design condition and you
16 have minimum heat loads in the control room? So we
17 also looked at that.
18 The analysis, the initial analysis shows
19 that we're within our limits for those three
20 conditions. We don't exceed the 50-degree heat up
21 which is the design constraint. The models are less
22 than 95 degrees after the period of time in question.
23 The limiting condition is the zero percent exceedence
24 value. So the condition with the humidity resulted in
25 a less limiting condition than zero percent.

1 During the winter time load, the control
2 room temperature went down to around 61-62 degrees, so
3 that's an acceptable value there.
4 MEMBER CORRADINI: If I might just
5 interrupt so I make sure, now this is -- because when
6 we were together before Thanksgiving, you guys were in
7 the midst of doing these calculations. Have these
8 been passed over to the staff?
9 MR. ARCARO: They are still in review at
10 GE.
11 MEMBER CORRADINI: Okay, fine. So the
12 staff has yet to see them.
13 MR. ARCARO: That's correct. And there is
14 an open RAI that we're answering with these questions.
15 MEMBER CORRADINI: Right. One follow-up
16 question then, relative to -- if I understood what you
17 said, is you used one computational pool for the hot
18 and one for the cold?
19 MR. ARCARO: That's right.
20 MEMBER CORRADINI: Why?
21 MR. ARCARO: The contain won't work with
22 negative numbers, so if we're analyzing a -40 degree
23 temperature --
24 (Laughter.)
25 MEMBER CORRADINI: Wait, wait, wait.

1 MEMBER STEKAR: You can have a great hit
2 that goes like this, but not like this.
3 MEMBER CORRADINI: You mean the bloody
4 thing is coated with degree C instead of degrees K, is
5 that what you just old me?
6 MR. ARCARO: My understanding was it
7 doesn't work for --
8 MEMBER SIEBER: A Y2K problem.
9 (Laughter.)
10 MEMBER ABDEL-KHALIK: How do the results
11 of this new calculation differ or compare to the
12 results that were presented back in November?
13 MEMBER CORRADINI: We didn't have results
14 back in November.
15 MEMBER ABDEL-KHALIK: They presented some
16 results and simple back of the envelope calculations
17 showed that this is nonsensical.
18 MR. ARCARO: Shows that it's what?
19 MEMBER ABDEL-KHALIK: That the results
20 were nonsensical. If this were to happen in the
21 middle of the summer on a very hot day, it wasn't
22 clear that you could ever meet this requirement of 117
23 degrees?
24 MR. ARCARO: I think the results show that
25 117 degrees, the heat up rate in the control room will

1 be less than the limit in the 72-hour period.

2 MEMBER ABDEL-KHALIK: Will we have the

3 opportunity to review the details of this new

4 analysis?

5 MS. CUBBAGE: First, the staff needs to

6 receive it. So that would be the first step. The

7 Staff, we're not planning to present on this topic

8 today because we don't have any new information from

9 when we were at the Subcommittee meeting, but yes, we

10 will come back with the resolution of this issue to

11 the Committee.

12 MEMBER ABDEL-KHALIK: If we want to see,

13 I'm sure the Staff will share it with us.

14 MS. CUBBAGE: We will be happy to provide

15 that, when it's submitted.

16 MEMBER ABDEL-KHALIK: One of the issues

17 that the staff raised as well in that the analyses

18 appeared to be inadequate when the results seemed to

19 be unreasonable.

20 MS. CUBBAGE: When the response comes in,

21 I'd be happy to provide it through the ACRS Staff and

22 we'll present our conclusions about it later.

23 MEMBER STEKAR: May I ask a couple of

24 questions? I want to ask one question and also make

25 a point of concern.

1 The question is do your heat-up
2 calculations for the control room just look at bulk
3 control room air temperature or do you look at
4 temperature within the various cabinets where the heat
5 loads and the sensitive equipment actually exist?
6 MEMBER BLEY: Actual temperature
7 conditions inside the cabinets.
8 MEMBER STEKAR: Within the cabinets, not -
9 - even if it's a lump, I think John's point is if you
10 have a heat-producing element somewhere and the
11 cabinets are going to have a delta T that you --
12 MEMBER BLEY: Cabinets have power
13 supplies.
14 MEMBER STEKAR: Right, right.
15 MEMBER BLEY: They're the heat generators.
16 MR. MARQUINO: This is Wayne Marquino of
17 GE. The calculations that Mr. Arcaro is referring to
18 are volt temperature calculations. The cabinet
19 calculations take that as an input and as part of the
20 EQ program for ESBWR, when we have the detailed
21 procurement of the equipment, we know how much is
22 going to be in each cabinet, then we do that
23 evaluation.
24 MEMBER STEKAR: That has not been done
25 yet, but the volt temperature would feed into that.

1 MR. MARQUINO: Yes, sir.

2 MS. CUBBAGE: An implementation of the EQ
3 program is post-design certification.

4 MEMBER STEKAR: The point is they don't
5 have the cabinet designs yet, so they're not quite
6 sure what's there.

7 The second item that I wanted to bring up
8 is that your presentation today has focused on the
9 control room habitability which is one area of concern
10 that we have.

11 We also or at least I have concerns
12 regarding room heat up in the remainder of the control
13 building, control building general areas that do have
14 safety-related cabinets in them. And possibly more
15 limiting might be the reactor building where there are
16 even larger -- the averters are out there and you have
17 more safety-related cabinets out in the reactor
18 building areas.

19 And I think we brought that up at the
20 meeting. The focus seems to keep coming back to the
21 control room which may or may not be the most limiting
22 location.

23 MEMBER CORRADINI: I think we mentioned
24 it. I think actually in the letter, as we've been
25 going back and forth in the draft, it's there.

1 MEMBER STEKAR: I just didn't want those
2 other two areas to get lost in the noise with the
3 focus on the control room and if indeed the control
4 room is evaluated as being acceptable saying the whole
5 problem is solved -- it's not.
6 MEMBER ABDEL-KHALIK: I guess I am just
7 concerned about the superficiality of this
8 presentation. There is nothing here on a technical
9 level for a committee of this type to evaluate or
10 review.
11 MR. JORDAN: Our approach --
12 MEMBER ABDEL-KHALIK: Simply your comments
13 that we have developed a model. We've done the
14 calculations and we've responded to the questions.
15 MR. JORDAN: Our approach on these
16 presentations, again, because of the limited amount of
17 time provided for the four chapters to be discussed
18 was not to get into specific details.
19 MEMBER CORRADINI: That is partly -- let
20 me interject. In some sense, that's my fault in the
21 sense that we had a two-hour window. We had to go
22 through the four chapters and I told them to address
23 the key concerns that we had discussed from the
24 subcommittee meetings. So in some sense that's at my
25 direction. I think they have enough of a staff out

1 there that if you have questions, you should bring
2 them on and the staff, they look like happy campers
3 out there. They should be ready to answer them.
4 MEMBER ABDEL-KHALIK: But how would a sort
5 of a presentation or the comments, how would the
6 comments made with regard to the passive heat sink
7 issue with regard to control room habitability that
8 were presented just a few minutes earlier assure a
9 committee of this type that what you've done is
10 adequate?
11 MR. KINSEY: This is Jim Kinsey from GE
12 Hitachi. I guess to help with that answer, as Amy
13 pointed out, and as the team has pointed out, we've
14 continued our evaluation of these topics since our
15 last gathering. We are giving you a summary of what
16 the results are telling us at this point as we're
17 finalizing those results, that we still need to
18 transmit those to the NRC staff and I assume we'll
19 have some dialogue there regarding those results, but
20 again, we're providing you a status of our activities
21 in this area.
22 MEMBER MAYNARD: I think that we have
23 drawn more from the Staff's evaluation for this
24 particular one. They haven't received it yet, but I
25 don't think we just take what the applicant says. We

1 have to then talk to the Staff about did they review
2 and what did they review and what was done to confirm
3 what the applicant has said.
4 MS. CUBBAGE: I would not expect you to be
5 making any conclusions about this topic based on what
6 you're hearing. You're absolutely right.
7 MEMBER CORRADINI: It's still an open
8 issue. In this one case we heard that you guys were
9 in the middle of it, had some results, were going to
10 talk about them, and still had to do more work, were
11 in the process of transmitting them to Staff. But I
12 think Otto's point is fair is that we -- this is step
13 one, and we have a couple more steps to review before
14 we pass on it. So this is more in the sense of
15 progress report.
16 MS. CUBBAGE: And Staff is not satisfied
17 at this point. We don't have the information.
18 MEMBER SIEBER: The place for the details
19 is in the Subcommittee.
20 MEMBER STEKAR: I don't know if this is
21 appropriate to ask, but it's come up. How far along
22 are you or is it not worthwhile asking in terms of
23 going out for procurement of the DCIS equipment?
24 MEMBER CORRADINI: That's right. You
25 asked that three months ago. Ask it again.

1 (Laughter.)

2 MEMBER STEKAR: Are you close or not?

3 MR. TUCKER: This is Larry Tucker with
4 GEH. GE's work on the ESBWR as part of the 2010, that
5 phase for certification and certain other activities
6 associated with the design of the ESBWR. There are no
7 funds for equipment. So in terms of business cycle,
8 we're working to the 2010 program.

9 MEMBER STEKAR: Thank you.

10 MR. ARCARO: The second topic on control
11 room habitability has to do with actual habitability.
12 The question was how do we maintain habitability
13 during the period where you lose off-site power and
14 the way we do that is through emergency filter units,
15 under a radiation event, or an accident, the control
16 room will isolate the emergency. Filtration units
17 will operate to maintain the system in a habitable
18 condition. We maintain the life support per ASHRE-62.
19 There's a flow rate required to maintain the required
20 amount of -- the required quality of air for the
21 operators in the control room.

22 And that system also maintains, in
23 addition to the required flow rate, it maintains the
24 positive pressure that's assumed in the dose and
25 leakage requirements for control room dose concerns.

1 To do that, we maintain 424 CFM and
2 maintain a positive pressure of an eighth of an inch.
3 One of the RAIs that we're responding to had -- was
4 asking about how do you maintain that flow rate and
5 the way we'll do that is have a controlled bleed off
6 point to make sure that we have the required flow
7 going through the control room habitability area to
8 maintain life support for the operators.
9 The next topic of concern -- or topic of
10 consideration --
11 MEMBER MAYNARD: I'm sorry, back up just
12 a minute. Control bleed-off point, is that some type
13 of an automatic control or would it be a manual
14 control? I take it it's basically going to be
15 controlling the DP across something so that you keep
16 an air flow through there?
17 MR. ARCARO: That's correct.
18 MEMBER MAYNARD: Something has got to be
19 making the adjustments, if needed.
20 MR. ARCARO: What we'll do is dependent on
21 the leakage of the control room habitability area,
22 we'll size it in order to get that minimum flow rate,
23 so we'll maintain, based on the fan curve, we'll
24 maintain a pressure at the flow, so it would be an
25 orifice that could be adjustable depending on the

1 leakage you get through other paths and it would be
2 located where you could get the flow rate to flush the
3 different spaces to maintain the life support
4 requirements.
5 MEMBER CORRADINI: This is on the
6 downstream side, am I correct, right, for exhausting?
7 MR. ARCARO: That's correct.
8 MEMBER CORRADINI: Because just to go back
9 a little bit, if I remember back in November where we
10 were asking this was we didn't see anything so that
11 led to the questioning of it. So this is still in
12 design or it has been designed?
13 MR. ARCARO: Still is in design.
14 MEMBER CORRADINI: Okay, fine.
15 MEMBER MAYNARD: Now this addresses the
16 long-term, the after the 72-hour time frame?
17 MEMBER CORRADINI: No, this is during the
18 72 hours, I think, right?
19 MEMBER MAYNARD: So what if you don't have
20 a fan running?
21 MR. ARCARO: You will have a fan running.
22 The fan will be running -- it's a safety-related fan.
23 So you either run it on the safety-related power or
24 post-72 hours you actually have a generator that's
25 going to provide power for that fan.

1 MEMBER MAYNARD: Okay, so it would
2 basically be a battery -- a battery would be running
3 a fan?
4 MR. ARCARO: That's correct.
5 MEMBER MAYNARD: All right.
6 MEMBER STEKAR: The air supply hasn't been
7 a problem. It's battery powered and it's getting the
8 through put of ventilation, basically the exhaust
9 that brought the question up.
10 MR. ARCARO: The last topic of discussion
11 had to do with having the heat transfer, evaluate the
12 cooling for fuel bundles in the inclined transfer
13 tube.
14 MR. DEAVER: This Jerry Deaver. I'll be
15 discussing this issue. What we've done in this area
16 is that the inclined fuel transfer system is, in
17 essence, the same as what we have in BWR6. So in
18 going back and reviewing the work that was performed
19 for those plants, we found that it's bounding for the
20 ESBWR design and the limiting case for heating is with
21 the inclined fuel transfer tube, the sliding assembly
22 in the full-down position and with the water drained
23 off. That's the normal process for equalizing the
24 water line such that you can take out the bundle in
25 that condition. That represents the minimum amount of

1 water that would be in the tube at that time to
2 provide cooling. And the results of the BWR-6
3 analysis said they had 10 hours to facilitate a repair
4 or a change to get the bundles out.
5 And there are several options. Either you
6 can open a valve up manually at the bottom of the tube
7 to facilitate flow or you can basically close the
8 drain line off and refill the tube so you have plenty
9 of water. So at this stage, we know that the analysis
10 is bounding and we will be doing the detailed analysis
11 ultimately to establish the hours associated with the
12 ESBWR.
13 We find that the water height in an ESBWR
14 is much higher than the BWR-6.
15 MEMBER CORRADINI: Now, you reminded us of
16 this. What plants right now have this sort of
17 arrangement that also have gone through this analysis?
18 I can't remember.
19 MR. DEAVER: There's Clinton, Riverbend,
20 Grand Gulf, Perry, that vintage of plants.
21 So at this point --
22 MEMBER MAYNARD: The ESBWR has the same
23 elevation differences and incline as your BWR-6s do?
24 MR. DEAVER: It's a different angle and it
25 will be a longer movement of the bundles down to the

fuel building, but the basic concepts are all the same. It will have a tube. We'll load the tube with one or two bundles and they'll be trolleyed down to the lower elevation where the fuel building is.

The major difference is that in the BWR-6, they actually had a breach containment. In the ESBWR design, we don't have to do that.

MEMBER CORRADINI: You're still within the dry well?

MR. DEAVER: Yes, that's right. I'm sorry, no, I misspoke.

MEMBER STEKAR: Is the BWR-6 incline transfer tube designed for tube bundles or only --

MR. DEAVER: It is.

MEMBER STEKAR: It is, okay. I'm familiar with the operations. I just didn't know whether it was designed to handle --

MR. DEAVER: Yes, it was.

MEMBER STEKAR: Okay.

MR. KAUFMAN: Okay. I guess that concludes the Chapter 9 discussion and we're moving to Chapter 10, provided by Jack Noonan. This is a pretty easy chapter to go through, so I would challenge you to go for five minutes.

(Laughter.)

1 MR. NOONAN: My name is Jack Noonan. I'm
2 a senior engineer in the VOP group at GE Hitachi.
3 We're going to be talking briefly about the Chapter 10
4 of the DCD.
5 I just want to give a design overview.
6 Chapter 10 considers all the guidance in NUREG 0800,
7 at least from Section 10-2 to Section 10-47. The
8 turbine generator and pyrocycle systems do not perform
9 any -- or support any -- nuclear safety-related
10 functions.
11 The ESBWR BOP is based upon a very
12 conventional BWR 6 plant cycle. It's approximately 20
13 percent larger, about a 1600 megawatt electric gross.
14 As far as the turbine and generator, the
15 turbine rotors use integral forgings, monoblocks,
16 sometimes. It is minimizing the probability of
17 missile generation. The fully bladed rotor assembly
18 is spin tested at the factory to 120 percent of rated
19 speed. GE has a fairly long history with this design.
20 This replaced the previous design of the shrunk on
21 wheel that was used in the industry prior to the '90s.
22 The generator is a standard design
23 synchronous generator with water-cooled stator
24 windings and a hydrogen cooled rotor. This is, like
25 I said before, approximately 1600 megawatt electric

1 gross, rated at 1933 MVA.

2 MEMBER CORRADINI: That's the size the

3 turbine can handle? Can you go back and repeat what

4 you said? I apologize. I was reading something.

5 Okay, thank you very much.

6 MR. NOONAN: As far as turbine missile

7 considerations, as I mentioned earlier, we have

8 integral forgings, monoblock rotor. This turbine is

9 favorably oriented so that the hazard zone or the

10 strike zone, as some people call it, of the turbine

11 missiles is away from the containment and reactor

12 building.

13 BOP pumps are adjustable speed motor-

14 driven feed pumps capable of 33 to 45 percent flow.

15 We use four feed pumps, essentially three running and

16 an installed spare.

17 We've eliminated the gland seal steam

18 evaporator with improved reliability and actually

19 reduced the dose associated with maintenance on the

20 gland seal steam evaporator.

21 Overspeed protection system is a fully

22 electronic, redundant, fail-safe, and testable system

23 using 6 probes.

24 To summarize, ESBWR Balance of Plan is

25 designed with flexibility and basically can be sited

1 anywhere in the U.S. where the design parameters for
2 the cooling water systems are met. It is one basic
3 design.
4 The design incorporates best practices and
5 industry lessons learned. Some of those that I talked
6 about were the arrangement of the feed pump where you
7 have an installed spare. Basically, the loss of a
8 feed pump would not lead to a reactor trip. We use a
9 feedwater tank which allows you to basically withstand
10 the loss of a condensate pump and not have a reactor
11 trip. There's a full bypass and the plant is capable
12 of high-end load operation.
13 Basically, you know, the design of the BOP
14 for ESBWR really was with the goal of eliminating
15 plant transients using lessons learned in the industry
16 on events that were initiated from balance of plant
17 transients and improving plant availability through
18 on-line testing and maintenance.
19 I think I made it in five minutes.
20 MR. JORDAN: Less than that. Good.
21 MEMBER STEKAR: That, in the Subcommittee
22 meeting we noted that the feedwater system has in the
23 basic design that we've seen a single low-flow control
24 valve so that if you have to run -- you have to
25 control feedwater at low loads, you're dependent on a

1 single valve.

2 You said at that time you were considering

3 a possible design modification to install a redundant

4 valve. Has a decision been made yet? And if so, what

5 was the decision?

6 MR. NOONAN: There has not been a decision

7 made on that.

8 MEMBER SIEBER: I would think that

9 probably it would not be very severe because of

10 variable speed couplings that you have. You can match

11 horsepower, output of the motor, required to drive the

12 pump to balance the flow.

13 MR. NOONAN: The low-flow control valve is

14 generally in use when you're not running a feedwater

15 pump. It's during start up. So you don't have that

16 feedwater pump consideration at that time.

17 MEMBER CORRADINI: Can I ask a different

18 question?

19 So in a Subcommittee meeting that you

20 probably weren't at, but this is your Chapter 10, so

21 it's kind of fair game, the discussion was to

22 essentially change the operation, to change the

23 feedwater temperature, therefore to give you more

24 maneuverability within the core behavior.

25 How does that affect the actual system

1 here? Would you change anything in the design we've
2 seen or is this simply a change in the flow rate
3 within the design?
4 Do you folks know what I'm asking?
5 MR. UPTON: Yes.
6 MEMBER CORRADINI: Is it a change in the
7 operation using the same equipment, or is there a
8 modification of the equipment? You were displaced a
9 few months in time and I wanted to make sure there's
10 a connection.
11 MR. UPTON: Yes. This is Hugh Upton with
12 GEH. What we've actually done is the seven stage of
13 feedwater heating that's been installed in the system.
14 It's always there. It's always warm, but when we
15 decide to valve it in, that's when you're going to get
16 higher feedwater temperatures in the impact reactor
17 power.
18 MEMBER CORRADINI: Okay, so the feedwater
19 here is there and essentially it's kept toasty and
20 then it's valved in and out as necessary?
21 MR. UPTON: That's correct.
22 MEMBER CORRADINI: Okay, thank you.
23 It's a bypass. Primarily a bypass.
24 Thank you.
25 MR. JORDAN: Okay, moving on. As I

1 mentioned, we didn't have a specific presentation on
2 Chapter 13, but I'll open this up now if there are any
3 comments or questions that any of the Members may
4 have.
5 Hearing none, we'll go to Dan Williamson
6 to talk about --
7 MEMBER CORRADINI: Before you go too fast,
8 so you're asking us about 13, aren't you?
9 MR. JORDAN: Yes.
10 MEMBER CORRADINI: So the one thing I'll
11 just remind you all because we have that for the April
12 9th Subcommittee meeting is that the one thing the
13 Committee was asking about and we were deferred
14 through when we talk about human factors was conduct
15 operation issues that essentially interact with human
16 factor concerns and that would be where we're going to
17 review it in Chapter 18. Correct? I just want to
18 make sure we're on the same page.
19 Right?
20 MEMBER STEKAR: Yes.
21 MEMBER CORRADINI: We delayed questions
22 here with the understanding that we'd bring them up
23 relative to Chapter 18 and human factors.
24 I just want to make sure the Committee
25 knows.

1 MEMBER STEKAR: The only -- for the
2 benefit of the Committee, anybody who wasn't at the
3 Subcommittee meeting, the only, I think, technical
4 questions that I have a note on anyway was regarding
5 the survivability of the technical support center for
6 longer than two hours during a station blackout. I
7 think your statement was that the technical support
8 center is not designed to be habitable after two
9 hours. It's strictly a two-hour time window.
10 MEMBER CORRADINI: So this is an HVAC
11 question relative to the --
12 MEMBER STEKAR: No, it's actually power
13 supplies.
14 MEMBER CORRADINI: Oh, power supplies.
15 MEMBER STEKAR: The entire design is
16 predicated on a two-hour use time window. I only
17 wanted to bring that up for the benefit of some of the
18 other Committee Members who might not have been a
19 party to that discussion.
20 MEMBER BLEY: We had discussed with you
21 folks at that meeting the idea of the development of
22 your emergency operation procedures being integral to
23 the development of the design and I think you told us
24 this work had just started to get underway and I
25 wonder when we'll hear more about that.

1 I'm not sure where that was going to get
2 picked up. Do you know?
3 MEMBER CORRADINI: Let's talk about this.
4 MR. MARQUINO: This is Wayne Marquino.
5 I'm responsible for the EPGs and EOPs for ESBWR as
6 part of the HFE process. It's covered through an ITAC
7 and it will be performed post certification. We're
8 staffing up and beginning to work on the EPGs and
9 EOPs.
10 MS. CUBBAGE: And the development process
11 we can discuss at the April 9th Chapter 18 meeting,
12 correct?
13 MR. MARQUINO: Yes.
14 MEMBER CORRADINI: Thank you. Okay.
15 MR. JORDAN: Okay, moving on to Chapter
16 16, technical specifications. I'll turn this over to
17 Dan Williamson.
18 MR. WILLIAMSON: Good afternoon. Quickly,
19 we'd like to just brief you on the preparation of the
20 tech specs.
21 Dan Williamson, GEH team lead for tech
22 spec. development. The tech specs for ESBWR were
23 based primarily on BWR/6 standard tech specs. We
24 utilized what's in existence. The operating fleet is
25 familiar with and licensed too, for the numbering

1 format content, rules of usage and therefore. We also
2 took specific evaluation of the ESBWR systems and the
3 ESBWR analyses and application of the 50.36 criteria
4 for what goes in tech specs, evaluated the ESBWR
5 specifics to ensure that we had the right systems and
6 the right components within the tech spec scope, using
7 the precedence of an existing standard tech spec to
8 establish the form format actions, completion times.
9 One of the things that wanted to be talked
10 about specifically --
11 MEMBER SIEBER: Before you skip that last
12 slide or move from it, completion times and
13 surveillance frequencies are based on engineering
14 judgment. There has been a movement for some time to
15 make it risk-based. Had you considered that at all?
16 MR. WILLIAMSON: We considered several
17 options. Certainly the move afoot in existing fleet
18 is to use risk-based arguments to extend completion
19 times and the Reg. Guide 174, 177, I think it is,
20 provides the application of risk-informed extensions
21 to completion times for surveillance frequencies.
22 As a base, as a starting point, to
23 facilitate the review and just start in the same
24 ground if you will, as the existing fleet, we utilize
25 existing deterministic-based completion times and

1 frequencies to the extent they apply to the similar
2 systems.
3 Moving forward in the future, we would
4 expect the same application to dovetail in with the
5 existing fleet on efforts that they're making in the
6 risk-informed tech spec improvement area. We didn't
7 want to spearhead out and do anything too new and
8 different at this time for ESBWR basic certification.
9 MEMBER CORRADINI: So if there's some sort
10 of result from those efforts this might be modified
11 relative to it?
12 MR. WILLIAMSON: It would be considered as
13 future activity to be considered.
14 MEMBER APOSTOLAKIS: Would you do it now?
15 I don't think so. Wouldn't you need more detail to
16 put in the risk calculation?
17 MR. WILLIAMSON: That is certainly a part
18 of it is the risk -- that the PRA needs to evolve and
19 mature to support those kind of activities.
20 MEMBER APOSTOLAKIS: When you say the PRA,
21 you mean the PRA for the ESBWR?
22 MR. WILLIAMSON: Yes, I do.
23 MEMBER CORRADINI: Dan, let's let Mr.
24 Jakobiac address this.
25 MR. JAKOBIAC: Rick Jakobiac from GEH.

1 One of the things that we're doing with the ESBWR PRA,
2 as you well know, the design PRA excludes credit for
3 things like operators for the most part. There's a
4 few operator actions that we take credit for, but in
5 general, it's not to the same level of detail in that
6 area as the PRAs that are being used to modify
7 technical specifications in the existing plants.
8 So rather than do a partial risk-informed
9 tech spec now with a PRA that isn't exactly what the
10 rest of the utilities are using, it's a different
11 level of detail in areas like the humans and the
12 procedures, things like that, doing a partial now and
13 then another partial later, we thought it would be
14 best to use the as-built PRA, if you will, as a basis
15 for going forward with any sort of risk-informing of
16 tech specs.
17 MEMBER APOSTOLAKIS: I didn't understand
18 the last sentence.
19 MR. JAKOBIAC: The question was were we
20 going to do risk-informed completion times.
21 MEMBER APOSTOLAKIS: You are not?
22 MR. JAKOBIAC: And we are not in the
23 design phase.
24 MEMBER STEKAR: Let me ask you though, I
25 thought I understood the first part of your discussion

1 saying you took limited credit for human performance
2 in the PRA which I would understand as limited credit
3 for operators manually helping out to mitigate an
4 accident sequence. It's not clear to me what
5 relevance that has to testing and maintenance
6 frequencies and the modeling of durations that
7 equipment are out of service or the frequency of
8 testing. That's not necessarily a human performance
9 conservatism.
10 MR. JAKOBIAC: By excluding things like
11 operator actions and by using generic data and things
12 like that, it tends to push the risk metrics like risk
13 achievement where it's up very high and you would get
14 very, you'd get more limited benefit from trying to
15 risk inform some of these completion times because the
16 importance measures of the components that you're
17 looking at are artificially high.
18 We know they are artificially high because
19 we haven't taken credit for certain types of
20 recoveries.
21 MEMBER STEKAR: You mean real live?
22 MR. JAKOBIAC: Real live recoveries. So
23 --
24 MEMBER SIEBER: Wouldn't that be better
25 than an engineering judgment? There's no real basis

1 for the completion times and surveillance intervals
2 for the engineering judgments.
3 MR. JAKOBIAC: I think that's a good
4 point, but one other thing that we have to consider
5 with this is it's been very difficult for the existing
6 plants to risk inform their technical specifications.
7 That's a very long, arduous undertaking. And if we
8 were to combine a new plant license with a partial
9 risk informing of the technical specifications, I
10 think we would be at a different time line than we are
11 right now.
12 I think we'll get there, but not on the
13 certification time line.
14 MEMBER STEKAR: In the PR, we haven't seen
15 the PRA yet, so we have a version, but it's -- what I
16 wanted to ask is you mentioned generic data. The
17 testing frequencies, obviously, are specified in the
18 tech specs, so you must be using those.
19 MR. JAKOBIAC: To the extent that they
20 apply, yes.
21 MEMBER STEKAR: Okay. Maintenance
22 unavailabilities are based on historical data from
23 operating plants or are they based on estimated
24 frequencies where the tech spec allowed outage times?
25 MR. JAKOBIAC: The tech spec allowed

1 outage times are associated with it and we also have,
2 in our design specs, target reliability values that
3 help inform what we would put the unavailabilities at.
4 MR. WILLIAMSON: We also wanted to talk
5 specifically about the passive systems, the
6 surveillance that are conducted on the passive systems
7 and the frequencies. As an example, we'll talk about
8 GDCS specifically. And again, we applied precedence
9 in our engineering judgment, precedence for similar
10 systems, similar applications in establishing our
11 surveillance and surveillance frequencies.
12 In the case of the gravity-driven cooling
13 system, there's an inspection for flow obstruction, a
14 10-year surveillance, typical of systems that are --
15 that don't experience flow. You don't have a
16 quarterly pump flow, systems that rely on FME, foreign
17 material exclusion, and cleanliness. Containment
18 spray headers have a 10-year frequency. Similar
19 systems in AP1000 have a 10-year frequency.
20 MEMBER APOSTOLAKIS: Where is this 10-year
21 frequency specified?
22 MR. WILLIAMSON: In the surveillance
23 requirement for the --
24 MEMBER APOSTOLAKIS: No, no, no. You said
25 there is a basis some place.

1 MR. WILLIAMSON: Precedent. Similar
2 systems, passive systems that don't experience any
3 flow or any mechanism for degradation have
4 historically had a 10-year inspection for flow
5 obstruction.
6 MEMBER APOSTOLAKIS: Such as?
7 MR. WILLIAMSON: Containment is the one
8 that comes to my mind. Containment spray is one, is
9 the classic example, I think. There are other systems
10 that don't -- for instance, the AP1000 has similar
11 systems to the ESBWR and have a similar 10-year
12 frequency applied for.
13 MEMBER CORRADINI: So let me just broaden
14 this question because this one, I don't know enough,
15 but I want to make sure I understand the thinking
16 process of you guys.
17 So now I've gone from a current light
18 water reactor where the only passive system, the
19 notable passive system is the building, the
20 containment, and all associated things. And there,
21 there's a containment leak rate test every 10 years.
22 So now I was looking at the frequency here, so now you
23 mentioned this one and I was looking down at the
24 isolation condenser. So is the basis to use what is
25 currently passive systems or safety systems that have

a passive attribute and use that sort of frequency or is there a -- what is the technical basis for rather than history says we did it and it seems okay and we'll keep on doing it that way?

MR. WILLIAMSON: That would be the engineering judgment basis. There are other preventive maintenance activities.

MEMBER CORRADINI: Right, I can imagine.

MR. WILLIAMSON: There's ISI and IST on the check valves and flushing of the lines that occur, but the tech spec required operability verify there's no obstruction is a span of 10 years.

MR. DEAVER: I think if you look at the system, the geometry of the system with the gravity-driven pools and such and the screens that basically allow venting at the top, there's just not any real opportunity to -- the screens have limited whole sizes and such. The opportunity to get debris into the pools in the first place is very limited so flow obstruction, you know in a totally stainless steel system just seems to be a remote possibility.

MEMBER CORRADINI: I understand. Can you remind me for the gravity, for the GDCS what is the pipe diameter coming into the vessel? I forget now?

MR. DEAVER: It's six inches.

1 MEMBER STEKAR: Are these the only access
2 points with regard to foreign material exclusion?
3 MR. DEAVER: Well, we have valves, but
4 basically the piping that goes from the pool to the
5 vessel, there are only maintenance valves, squib
6 valves, check valves, that sort of thing. So the only
7 opportunity is you are somehow taking a valve apart
8 and you happen to leave something inside. That would
9 be the only opportunity.
10 CHAIRMAN SHACK: And historically, given
11 the importance of this system, historically you
12 believe that a 10-year frequency is adequate?
13 MR. DEAVER: Yes, and the valves
14 basically, the squib valves basically, we just check
15 the charge to make sure that that's operable. We
16 don't really need to take the valve apart. The check
17 valves get stroked in every outage and such. So
18 there's not much need to do maintenance on these
19 valves in the first period.
20 MEMBER ABDEL-KHALIK: There is no other
21 activity during an outage where other foreign material
22 can get into the system and cause partial blockage?
23 MR. DEAVER: That's what I find hard to
24 imagine because each location of the pools and the
25 vent being right at the top of the ceiling of the

1 containment and the limited access with the perforated
2 holes in the plate to prevent debris from entering
3 into the pool. So there just doesn't seem to be any
4 opportunity. Somebody would have to purposely do
5 something to cause an obstruction.
6 MEMBER STEKAR: This is just a point of
7 personal ignorance and maybe somebody on the Staff
8 might know, what are the current requirements for
9 injection flow verification from pressurized water
10 accumulators, actual flow verification testing? Does
11 anyone know?
12 MR. HARBUCK: I'm from the Staff. My name
13 is Craig Harbuck. There are no pressurized water
14 accumulators.
15 MEMBER STEKAR: We're talking about the
16 current plants, existing plants.
17 MR. HARBUCK: That's another passive
18 system.
19 MEMBER STEKAR: That is a very, very
20 similar low-pressure injection type of system. So in
21 terms of looking at precedent, I would certainly be
22 curious about what the requirements are for functional
23 flow testing of pressurized water reactor accumulus.
24 They're very, very similar.
25 How do you verify it?

1 Periodically, you actually have to open a
2 valve and make sure the level of the accumulator goes
3 down and level in the vessel goes up. I was just
4 curious, how frequently people do that because I know
5 some years ago when I was operating we did one
6 accumulator per outage per year.
7 MR. KINSEY: Dan or Jerry, maybe you want
8 to talk about flushing water down the line?
9 MR. WILLIAMSON: I just pulled up the
10 Westinghouse existing fleet Westinghouse tech specs
11 for 351, their accumulators. And they have no flow
12 surveillance. They have a verified nitrogen pressure
13 every 12 hours, verified boron concentration every 31
14 days, and verified the powers are moved from the
15 isolation valve every 31 days.
16 MR. WILLIAMSON: I happened to have been
17 in the same plant that he was and I remember doing
18 this test.
19 MEMBER STEKAR: But that was all. I was
20 curious what's current. I'm not trying to be
21 contentious. I'm just curious.
22 MR. KINSEY: At a PWR, when you do that
23 test, when you inject, you're actually doing it to
24 check the check valve.
25 MEMBER STEKAR: That's right. But it's

1 the same --

2 MR. KINSEY: Same outage.

3 MEMBER SIEBER: But the flow rate is a

4 function of --

5 MEMBER STEKAR: Is that still the case on

6 existing plants?

7 MR. WILLIAMSON: That is based on the BWR

8 at I worked at.

9 MEMBER STEKAR: That's my case, too, but

10 that was 30 years ago.

11 What's the third bullet under the GDCS?

12 MR. WILLIAMSON: What would be the ASME.

13 The ASME components have this requirement for stroking

14 and you do that for the flow test and the case --

15 MEMBER STEKAR: But it also functionally

16 verifies point to point. I mean water goes down here.

17 Water goes up over here, so you're actually verifying

18 the continuous flow, even though you're doing the test

19 to verify a particular component.

20 MEMBER SIEBER: The only way to measure

21 that is to measure the change in level.

22 MEMBER STEKAR: Yes.

23 MEMBER MAYNARD: I forget the frequency

24 and it's not all with the cumulative tech specs that

25 cover the surveillance that you do for flow because

1 you also have to flow through the check valves to make
2 sure that the check valves open and stuff there. So
3 there are periodic --
4 MEMBER STEKAR: I think that is another --
5 MEMBER MAYNARD: I forget the frequency.
6 MEMBER STEKAR: It's just a point that if
7 the 10-year frequency for the gravity-driven, the
8 GDCS, is as you mentioned based on industry practice
9 or precedent, I'm hoping that we're looking broadly
10 enough across industry practice and precedent for
11 similar types of passive injection systems.
12 MR. WILLIAMSON: And also, the ASME
13 requirements that apply to these passive components,
14 same tests.
15 MEMBER MAYNARD: I've got a question
16 primarily for the staff as to how much of the tech
17 spec is approved as part of the design cert. versus
18 how much for the -- as part of the COL.
19 MR. HARBUCK: This is Craig Harbuck again.
20 Most of the tech spec should be approved during the
21 design certification process. However, there are some
22 things which cannot be done at that time. The
23 surveillance for the passive ECCS should be
24 established during the design certification as well as
25 the frequencies.

1 MEMBER MAYNARD: It's important to get the
2 frequencies right at this point.
3 MEMBER SIEBER: It would be nice.
4 MEMBER STEKAR: Frequently enough because
5 of the pressure later to make them less frequent.
6 MEMBER CORRADINI: I think we can.
7 MR. WILLIAMSON: Isolation condensers is
8 another one that we briefly mention. We do have a
9 heat transfer test that's done at a frequency will
10 test one of the heat exchanger every 24 months to
11 confirm the transfer coefficient remains within the
12 analysis assumptions.
13 MEMBER CORRADINI: In 30 seconds, can you
14 remind me what that test is? We were debating
15 privately here. Remind me of what that test is?
16 MR. WILLIAMSON: It will be a test to
17 confirm the heat exchanger transfer coefficient.
18 MEMBER CORRADINI: And it is conducted
19 how?
20 MR. WILLIAMSON: That we don't have the
21 procedure drafted. We have in the bases, I had that
22 available to -- what's outlined in the bases. The
23 temperature sensor located downstream of the
24 condensate return isolation valve and the differential
25 pressure transmitter on the condensate return line may

1 be used to provide the test data. A brief summary of
2 the components, there are ways to do the test that
3 have been evaluated by engineering when we propose
4 this to ensure that the tests could be performed.
5 MEMBER CORRADINI: But let me just push
6 you a bit and so here's where I'm going back to
7 history. So I'm going to get the wrong plant. It's
8 not Oyster Creek, right? It is which plant?
9 MR. WILLIAMSON: Dresden.
10 MEMBER CORRADINI: Dresden.
11 MR. WILLIAMSON: I suspect.
12 MEMBER CORRADINI: So how did,
13 historically, Dresden check their isolation condensers
14 and I would assume you would have a similar sort of
15 test. What I guess we're worrying about, what I'm
16 worried about, I don't know about anybody else, is the
17 frequency of it again, but you've already said it's a
18 24-month period for each of the 4, so over 8 years,
19 you'll check them all and also the test because this,
20 to me is an important test to verify you've got
21 capacity.
22 So if you can point me to something I'm
23 happy to go read.
24 MR. WILLIAMSON: Meaning the Dresden
25 procedure or --

1 MEMBER CORRADINI: Just to understand
2 because I would think that knowing nothing else, you'd
3 use something, a standard similar to what you used in
4 the past.
5 MR. MARQUINO: This is Wayne marquino, GE.
6 So Dan Williamson is describing what parameters we
7 will measure during the test, we are still working
8 through the more specifics about the procedure in
9 terms of what operating point it will be. And you had
10 a request on trying to get you the procedure for an
11 operating plant and we'll work with our potential
12 customers that have isolation condensers to get that
13 information to the staff.
14 MEMBER CORRADINI: We're going to see you
15 for a little bit longer, so I don't think you're going
16 anywhere, but yes, we would like to see that.
17 MEMBER BANERJEE: I have a question. I
18 had to go to a meeting, so maybe I missed it, but is
19 there some tests being done for gas intrusion in these
20 GDCS lines?
21 MR. DEAVER: Let me answer that. We're
22 going to control that basically by geometry. The
23 squib valves will be the low point in the system such
24 that we'll slope the lines going towards the vessel
25 such that any gas entrainment in the nozzle or the

1 piping going to the squib valves will go back into the
2 vessel. The gas will not stay in the line and then
3 likewise, coming up from the squib valves, because of
4 the pools and the venting allowed by the pools, if we
5 slope the lines upward, then we don't get any
6 accumulation of anything. We always vent the system
7 such that there's no way to entrap gas or air in the
8 line itself.
9 MEMBER MAYNARD: I would be surprised if
10 the Staff doesn't require either at the design cert.
11 stage or at the COL stage some type of monitoring or
12 testing of this. There are issues with you can do it
13 by design, but by the time you do the design and that
14 you install it, it depends on design tolerances
15 sometimes. Sometimes you may have designed a line to
16 be where you know where the high point would be or
17 whatever, but in reality with tolerances and -- they
18 don't end up that way. So there has to be at some
19 point --
20 MR. DEAVER: There has to be a final check
21 or inspection.
22 MEMBER CORRADINI: This is one inch in a
23 hundredth slope, right?
24 MR. DEAVER: Yes.
25 MEMBER BANERJEE: That's not much of a

slope. I thought it was like a 20 degree --

MEMBER MAYNARD: There are some current issues with plants right now with a real low slope and that the construction tolerances and even the pipe not being straight, I mean you may have one end that's higher than the other, but the whole pipe is not at that angle, so there's --

MEMBER SIEBER: We occasionally find pipes that are bowed.

MEMBER MAYNARD: Yes.

MEMBER BANERJEE: And this is what, an 8-inch pipe?

MR. WILLIAMSON: Six inch.

MEMBER BANERJEE: Six inch. And we have relatively short runs coming out of the vessel until we get to the maintenance valve and then into the squib valve. Those are very short lines.

MEMBER CORRADINI: I think we are going to return to this one in Chapter 15 questions. I seem to remember somebody bringing up this question in other contexts.

MEMBER BANERJEE: In different contexts.

MEMBER CORRADINI: Yes. But we won't forget it. This one is important for a number of reasons relative to performance of the systems. I

1 agree with that.

2 MEMBER MAYNARD: This is critical.

3 MR. WILLIAMSON: We have already mentioned

4 several times squib valves. Obviously, there's squib

5 valves and we have the standard surveillance that

6 apply to squib valve applications today with verifying

7 continuity and the ASME requirements for sampling,

8 batch replacement, standard precedent applied for

9 squib valve testing.

10 Any more questions? I think we are

11 probably eating into the Staff's time already.

12 MEMBER CORRADINI: I think we are -- let

13 me go around and make sure that the Members have --

14 for the moment, are you guys okay?

15 All right. Thank you very much.

16 MR. WILLIAMSON: You're welcome.

17 MEMBER CORRADINI: We'll have a change in

18 the team.

19 (Pause.)

20 MS. CUBBAGE: Good afternoon, Amy Cubbage,

21 Lead Project Manager for the ESBWR design

22 certification. It's a pleasure to be back again.

23 (Laughter.)

24 I'd like to introduce some of the members

25 of the Staff over here to present with me today.

1 Gorge Hernandez from the Balance of Plant Branch and
2 NOR; David Shum, also from Balance of Plant Branch;
3 Craig Harbuck from our Tech. Spec. Branch. We also
4 have a number of members of the Staff in attendance to
5 address any questions you may have on top of this that
6 they're going to be addressing in the presentation.
7 So I'll give you just a little summary of
8 what we're going to be presenting. We're going to be
9 covering the topics of spent fuel passive decay heat
10 removal. That was a topic of interest at the previous
11 meeting. Inclined fuel transfer system, instrument
12 and service air, hydrogen water chemistry, emergency
13 lighting. There was a question on that. I'd like to
14 update you on where we're at with that.
15 On the steam and power conversion system
16 for Chapter 10, we don't plan a presentation there.
17 If you have questions, we have a reviewer for most of
18 that, and we have others here as well.
19 Chapter 13, again, no presentation
20 planned.
21 Chapter 16, Craig will be presenting some
22 of the topics of interesting including surveillance
23 requirements for ECCS and surveillance frequencies.
24 I'll turn it over to Jorge for our first
25 slide here.

1 MR. HERNANDEZ: Good afternoon. My name
2 is Jorge Hernandez from the Balance of Plant Branch in
3 NOR. I'll be briefly going over updates on the -- on
4 our review for the spent fuel pool decay heat removal
5 and also touch on the subject of the incline of fuel
6 storage transfer system which were topics that were
7 discussed as Amy mentioned in the Subcommittee
8 meeting.
9 After the Subcommittee meeting, we
10 reviewed the applicant's boiler analysis for the spent
11 fuel pool. In summary, essentially the analysis
12 concludes that following the loss of force going there
13 will be at least two meters of water of active fuel.
14 GEH calculated that 1690 cubic meters of water would
15 be lost during that 72-hour period. And this assumes
16 that the spent fuel pool is full at capacity and there
17 is one pool for offload also.
18 They also assume that the transfer gates
19 are closed and the analysis starts at the normal water
20 level which is 14.35 meters.
21 MEMBER BANERJEE: The two meters, is that
22 the collapsed liquid level or --
23 MR. HERNANDEZ: Yes. That will be
24 collapsed without voids.
25 They also specified three alarms. There's

one at the low level which is just below the normal --

MEMBER BANERJEE: How high are these fuel stacks?

MR. HERNANDEZ: Three point five meters. And the normal level is 14.35 from the bottom of the pool.

MEMBER BANERJEE: And where does the boiling start on this?

MR. HERNANDEZ: At 14.35. From the bottom of the pool. They would essentially lose 8.85 meters of water.

MEMBER BANERJEE: Sorry, is there boiling within the fuel or is it only boiling --

MR. HERNANDEZ: At the top.

MEMBER BANERJEE: At the top. So it's just -- I'm just trying to understand. So this is a pool full of water. In it, there's some fuel, right? Now you've lost convective cooling so eventually it has to boil. Natural convection can't take care of it and there's not enough -- is it boiling within the fuel bundles themselves or is it just boiling in that two meters above because to due to lack of gravity?

MR. HERNANDEZ: This is part of the -- there will be some boiling at the -- I believe that there --

1 MEMBER BANERJEE: In the fuel itself?

2 MR. HERNANDEZ: The thermohydraulic
3 analysis will show that there is enough flow going
4 through the racks such that there won't be trapped
5 voids within the racks and so they won't just all go
6 to the top.

7 MEMBER CORRADINI: So just to repeat so
8 I'm clear. Your boiling would first initiate at the
9 top of the fuel or near the top of the fuel, not
10 exactly at the top of the fuel, but near the top of
11 the fuel. Is that correct? I think that's what
12 Sanjoy is asking.

13 MEMBER BANERJEE: And then it will
14 propagate down or how far down?

15 They have two meters of water above.

16 MR. HERNANDEZ: The boiler analysis was
17 really a bulk type of analysis, assuming that there's
18 a heat source within the pool. And essentially you're
19 boiling an inventory of water so it doesn't go
20 specifically as to the racks themselves or the fuel
21 cells themselves.

22 MEMBER CORRADINI: Just to circle back to
23 what Professor Banerjee was asking. I think his point
24 is he's trying to understand the source of the vapor
25 and I think the source of the vapor is probably not at

1 the dead 3.5 meters, but a few right below that
2 because your delta T would be somewhere around in
3 there to start the boiling vessels.
4 MR. HERNANDEZ: And like I said the
5 analysis is not specific as to where exactly.
6 MEMBER CORRADINI: I understanding.
7 MEMBER BANERJEE: It is similar to
8 analyses that you do for other spent fuel pools?
9 MR. HERNANDEZ: Well, normally, you won't
10 go into a scenario where you're boiling the pool for
11 active plants, so you usually determine an analysis
12 that looks like normal operating conditions and
13 usually you have safety-related force cooling.
14 MEMBER BANERJEE: So why has this not got
15 safety related, because it's passive?
16 MS. CUBBAGE: It is a passive plant.
17 MEMBER BANERJEE: That's why there is
18 none. So this is sort of a unique situation in that
19 sense, right?
20 MR. HERNANDEZ: Correct.
21 MEMBER BANERJEE: And you haven't done a -
22 - at some point, there will be a detailed thermal
23 hydraulic analysis done of this.
24 MR. HERNANDEZ: What I've seen so far is
25 a thermal hydraulic analysis for normal operating

1 conditions, assuming that you have forced cooling.

2 MEMBER BANERJEE: That's easy.

3 MR. HERNANDEZ: There is no analysis for

4 that for the emergency scenario.

5 MEMBER BANERJEE: And in the current

6 plants, there is a backup system which is pumped,

7 right? Or not.

8 MR. HERNANDEZ: Correct.

9 MEMBER BANERJEE: Or does it depend on

10 boiling?

11 MR. HERNANDEZ: You essentially rely on

12 forced cooling for all the plants. In the AP1000,

13 that's a reactor that has also similar design which

14 you also boil in pool. Normally, you don't expect the

15 pool to be boiling.

16 MEMBER BANERJEE: It's interesting to have

17 a boiling pool for the fuel.

18 MEMBER MAYNARD: I am a little confused.

19 Even with the existing plants, they've all had to do

20 coping studies for station blackout and they've all

21 done --

22 MEMBER SIEBER: There's no cooling at all.

23 They just heat up the bulk water.

24 MS. CUBBAGE: I am not an expert in this

25 area, but I know this is unique in that it's a 72-hour

1 period rather than the --

2 MEMBER SIEBER: It's a design basis

3 condition.

4 MEMBER MAYNARD: But as far as the ability

5 to calculate the heat transfer and the boiling, how

6 long you can --

7 MEMBER SIEBER: Pretty simple.

8 MEMBER BANERJEE: But once you've been

9 boiling for 72 hours, I mean I don't know what's

10 happening to this. You've lost quite a bit of water

11 by then.

12 MEMBER CORRADINI: That's the whole point.

13 They go from the 8.5 to the 2.

14 MR. HERNANDEZ: Right, and at that point

15 you hook up the emergency makeup which is the --

16 MEMBER BANERJEE: But this is not fresh

17 fuel you're talking about.

18 MEMBER ABDEL-KHALIK: Sanjoy, a minimum of

19 two meters is maintained above the top of the active

20 fuel, just hydrostatic pressure difference between the

21 top of the pool and the top of the active fuel is

22 roughly 3 psi. And the corresponding change in

23 saturation temperature between the free surface of the

24 pool and the top of the active fuel is roughly 10

25 degrees F. So you may not have boiling inside --

1 MEMBER BANERJEE: That's what I was
2 asking.
3 MEMBER ABDEL-KHALIK: And you get
4 essentially a boiling as the pressure decreases as you
5 go up.
6 MEMBER BANERJEE: The question I was
7 asking is do you get boiling.
8 MEMBER SIEBER: As opposed to boiling in
9 the fuel, the assembly itself -- because the whole
10 pool is boiling.
11 MR. HERNANDEZ: The water heats up in the
12 fuel, but it will --
13 MEMBER STEKAR: I have a more basic
14 question since I don't understand how to boil water.
15 (Laughter.)
16 MEMBER STEKAR: There was some -- I'm
17 useless.
18 MEMBER BANERJEE: Do you know how to
19 percolate?
20 MEMBER STEKAR: No, no, that's a mystery.
21 Anyway, there was a discussion in the DCD, there are
22 a couple of places where it said that the -- my
23 question was that the heat-up analyses were performed
24 using 20 years' worth of spent fuel although the
25 current design capacity is only 10 years, right? Is

1 this calculation done -- you said you used spent fuel
2 full capacity. Is that 20 years' worth of spent fuel
3 or is that 10 years' worth of --
4 MR. JORDAN: Twenty years.
5 MEMBER STEKAR: Twenty years. Okay,
6 thanks.
7 MR. HERNANDEZ: I think GE rectified that
8 during the Subcommittee meeting.
9 MEMBER STEKAR: I just wanted to make sure
10 that where you say at full capacity was 20 years.
11 MR. HERNANDEZ: Yes. Like I said GE
12 specified three safety-related alarms. There's the
13 low-level alarm just below the normal level, but
14 within the two meter range, so it's not going to be
15 below, two meters below the normal level. There's the
16 safe shielding alarm as well that is located above 3.5
17 meters or 10 feet above the top affected fuel to meet
18 shielding requirements.
19 And there's also a type of factor fuel
20 elevation alarm which is essentially to the arrow,
21 temperature-related alarms that are announced in the
22 main control room and they would alert the operators
23 that the fuel has been exposed.
24 The Staff requested GE to address a
25 postulated drain. This was based on comments from the

1 ACRS of the Subcommittee meeting as well, for them to
2 address a scenario in which you would drain -- it's a
3 postulated drain through the gates and also to define
4 the distance between the top of active rule and the
5 bottom of the gates.
6 There's a statement in the DCD that says
7 they will have at least 10 feet of water. We just
8 want to know what's happening. How much they will
9 have and how much margin they will have.
10 With regards to the inclined fuel transfer
11 system, GE --
12 MEMBER MAYNARD: Sorry, is that still an
13 open item or an issue that's being --
14 MR. HERNANDEZ: Yes. They haven't
15 addressed that.
16 Again, based on the comments from the ACRS
17 during the Subcommittee meeting, we had a discussion
18 with GE regard the postulated loss of power to the
19 transfer to system and with two assemblies stuck
20 inside the transfer tube. They have indicated that
21 the analysis for the ESBWR is bounded by the BWR6
22 which they have already mentioned during this full
23 Committee meeting. And that it provides at least 10
24 hours of passive cooling before they start boiling.
25 The analysis basically assumes that the

assembly center is at the bottom of the tube and that the transfer tube is partially planing. They have also indicated that they makeup water can be added via the upper or the bottom valves or the upper manual valves and that doses have been analyzed.

We found that there is sufficient time and ability to provide makeup. It's acceptable. That's basically it.

MS. CUBBAGE: David Shum.

MR. SHUM: Good afternoon. My name is David Shum. I'm a senior engineer and I have reviewed the instrumentation and service in the systems project, the ESBWR.

By design, the systems are non-safety related systems and they do not perform safety-related function. They're not considered as a candidate for the RTNSS, and are not required to achieve or maintain safe shutdown of the plant.

MEMBER CORRADINI: Can I ask a question there just to -- it's for my edification. What qualifies a system to be part of a RTNSS system, part of the set of RTNSS systems?

MR. SHUM: They have to be usually as a defense-in-depth and have to make sure those are criteria specified in the Chapter 19 because there are

1 five criteria.

2 MS. CUBBAGE: We're going to get into a

3 lot of information on the RTNSS systems at a

4 subsequent meeting, but you know in a nutshell -- this

5 is regulatory treatment of nonsafety systems and there

6 are different ways that a non-safety system in a

7 classic plant could be elevated to raise additional

8 regulatory control and some of it there are

9 deterministic criteria that's being used as a post-72

10 hour defense-in-depth system.

11 MEMBER BLEY: When will we get to those?

12 MEMBER CORRADINI: That's what I was going

13 to ask you.

14 MS. CUBBAGE: June.

15 MEMBER CORRADINI: June.

16 MS. CUBBAGE: Chapters 19 and 22.

17 MEMBER CORRADINI: Twenty-two.

18 MS. CUBBAGE: Twenty-two of the Staff's

19 SER. It's covered in 19 of the applicant's DCD.

20 MEMBER CORRADINI: Thank you. We'll talk

21 about that then, but the one thing that just comes to

22 mind if we're looking at these systems under design

23 assumptions, if those design assumptions haven't been

24 realized in practice in operating plants, could that

25 elevate something to this list?

1 MS. CUBBAGE: I'm not sure of the
2 question.
3 MEMBER CORRADINI: Instrument air systems
4 often control -- and I don't know everything that's
5 air controlled here, often control things that would
6 be important except they're fail safe. But the way
7 they're fail safe is if pressure goes from full
8 pressure to zero, everything goes where it ought to
9 go. If it either decays very gradually or the system
10 is not completely clean, that assumption no longer
11 holds. If it decays gradually, things happen in
12 sequence that wasn't designed. There's plenty of
13 events showing that. If the system gets moisture or
14 debris in it, even at full pressure the outlet of the
15 compressor, odd things happen one at a time. Things
16 get starved for air and things move around. So the
17 assumption that it's fail safe might not -- hasn't
18 been realized in practice across the board.
19 So my question was if, in fact, there are
20 things here that might matter if that assumption of
21 fail safe weren't true --
22 MS. CUBBAGE: Well, due to the nature of
23 the passive plants I think they've made strides to not
24 require any of these active systems to be operable for
25 the safety systems to function. I'd have to call on

1 GE Hitachi or Dave to explain more about failsafe
2 nature.
3 CHAIRMAN SHACK: But I think Dennis'
4 question was are they designed -- if they're not
5 designed to operate, they're designed to fail safe and
6 if they don't fail safe, is there a problem.
7 MEMBER BLEY: Would that put you on the
8 RTLSS list then?
9 MR. ARCARO: This is Mike Arcaro from GEH.
10 The instrument air is not RTLSS. The safety function
11 is for those loads is performed by accumulators, so
12 that's why the high pressure air systems aren't
13 safety-related, aren't RTLSS. We did do an --
14 MEMBER BLEY: If it worked for the
15 accumulators, they might be?
16 MR. ARCARO: The URD and the design has
17 check valves or isolation between the air system and
18 the safety loads and then there is accumulators. So
19 if we didn't have the accumulators, then they would be
20 performing the safety function.
21 MEMBER ARMIJO: But the last bullet on
22 your chart there is a very strong statement and I'm
23 just wondering if that's really the Staff's position
24 that failure of the AIS or SES does not compromise any
25 safety-related system or component, nor does it

1 prevent a safe shutdown.

2 MR. SHUM: Yes, that's what we understand.

3 MEMBER ARMIJO: Is that your conclusion

4 that --

5 MR. SHUM: Yes.

6 MEMBER ARMIJO: That's a very strong

7 statement.

8 MR. SHUM: Based on what we understand

9 about the system.

10 MS. CUBBAGE: I think this ties into the

11 comment from GE Hitachi about the accumulators and the

12 nature of the arrangement of their pneumatic valves.

13 MEMBER MAYNARD: I think that probably for

14 this design, they are not really relying on it. They

15 rely more on the accumulators. For other plants, this

16 really is -- any operator will tell you the instrument

17 air system is one of the most important nonsafety

18 systems that you've got. But for the way this plant

19 operates, in the accident mode --

20 MEMBER STEKAR: It's not clear. It's not

21 clear.

22 MEMBER BLEY: We haven't seen enough for

23 it to be clear and I guess the thing that keeps

24 bringing it back to me is the key assumptions that the

25 check valves protect you from everything, that the

1 accumulators back you up, we've got systems out there
2 that have the same kind of things and have had
3 significant problems. So it just kind of feels like
4 operating history is disconnected from the review and
5 I don't know if that's true or not.
6 MR. SHUM: Normally, your accumulators
7 supply from the high pressure and larger supply
8 systems, normally. This is the case you've got the
9 air for the accumulator.
10 The instrumentation -- only connected to
11 that system, the high pressure, supply system outside
12 of the container as a back up.
13 MEMBER BLEY: Normally, everything works
14 great. There's always been, it seems, it appears
15 there's always been a design assumption that the way
16 air fairs is suddenly you lose a compressor and you
17 have no pressure. History tells us it fails in many
18 different ways and that way is well protected. All
19 the other ways may be not.
20 MR. SHUM: I agree with you, but this is
21 non-safety system. Our job is safety, our concern.
22 If it doesn't -- if the system fails, isn't
23 compromised, and safety-related system or event of the
24 safe shutdown, our job is done. I don't care whether
25 they have to shut the plant down or not. That's why

1 GE has to answer the question.

2 MEMBER BLEY: You've also claimed that

3 there's no way these are written systems and maybe

4 that's true, but what you just said was they would be

5 if you didn't -- if the accumulators didn't work.

6 MEMBER STEKAR: Let me ask something else

7 to get through this. Was there instrument air in the

8 PRA model? Does it model in the PRA?

9 MEMBER BLEY: And alternative modes of

10 failure model.

11 MR. WAKORVIAK: Instrument air is modeled

12 in the PRA. The alternative failure modes that you're

13 specifically talking about are captured in the data

14 for air-operated valves, so we don't specifically have

15 something that says the accumulator is at half

16 pressure or something like that.

17 MEMBER BLEY: I'd urge you to think about

18 that.

19 MR. WAKORVIAK: I understand --

20 MEMBER BLEY: It's a common effect.

21 MR. WAKORVIAK: I understand what you're

22 looking at, but we've got -- we can look at those

23 sorts of things.

24 The Staff has asked us in RAI about what

25 we -- about any other systems that may have what

1 you're talking about is covered under criterion E of
2 RTLSSs adverse system interactions. And what we've
3 said so far in that at this stage of the design it's
4 difficult to tell what adverse system interactions
5 there are because we don't have something to look at
6 and that's a very component-specific FMEA sorts of
7 things. You have to have something to look at to see
8 if there's an interaction.
9 We certainly wouldn't design in an
10 interaction like that, but sometimes because of
11 engineering you have to have things like that.
12 So the staff has asked for some sort of
13 assurance that these things will be looked at later.
14 We're in the process of answering that RAE and before
15 we get to Chapter 22, you'll have our response on
16 that.
17 MEMBER BLEY: Okay, thank you. One last
18 thing from me and I won't say anything more about the
19 air system. When we first went through this in the
20 Subcommittee meeting, the impression I got was this
21 didn't get looked at very hard because it's nonsafety
22 and it's not RTLSS.
23 But the review was based on sort of a
24 cartoon of the system which was very incomplete and
25 that nobody said gee, where's the real drawing of this

1 system? The bypass valves was where we started on
2 this. Are there bypass valves? No, there aren't any
3 on this picture. The picture was a cartoon. It
4 wasn't a real system drawing. It's troublesome.
5 Go ahead.
6 MR. SHUM: I agree with you. When we came
7 to the Subcommittee meeting, we -- our conclusion at
8 that time was based on Rev. 3.
9 MEMBER BLEY: Okay.
10 MR. SHUM: In Rev. 4, they decided --
11 MEMBER BLEY: But you didn't even have an
12 RAI on what's the system look like. That's what
13 bothered me.
14 MR. SHUM: By looking at the system, what
15 I call Mickey Mouse diagrams --
16 MEMBER BLEY: Fair enough.
17 MR. SHUM: It looked all right to me.
18 MEMBER ABDEL-KHALIK: So the determination
19 that this system does not perform a safety-related
20 function is based on -- and let me just guess the fact
21 that if you have an instrument air operated valve in
22 a safety system that is required to either fail as is,
23 fail open, or fail closed, that this will be -- that
24 this will indeed happen.
25 MS. CUBBAGE: You do not need the

1 instrument air system to be operable for any of the
2 safety valves to function.
3 MR. SHUABI: This is Mohammad Shuabi from
4 the Staff. I guess it's important. I'd like to add
5 that for example, when we do these chapter reviews,
6 aside from the PRA and aside from the RTLSS discussion
7 which will come later, this is design basis space type
8 review. So what we're looking for is is there a
9 safety function that needs to happen? Is there a
10 safety function of this valve of the system of this
11 component that we need to look at to make sure that
12 it's done correctly, it's designed correctly, it's
13 provided and described correctly in the DCD.
14 In this case, there is not a safety
15 function that the system is serving. The other thing
16 that we look at is is there something that the system
17 can do to prevent a safety system from performing its
18 job? That's another thing that we do when we look at
19 these systems and what you're hearing there is that
20 number one, this does not provide a safety function,
21 and number two, our conclusion is that it does not
22 impact the safety function.
23 Now when you get into PRA space and when
24 you look at severe accidents, other considerations
25 come in to play and that's where the comment was made

1 that in that area they do some modeling and they do a
2 little failure modes and things like that, but in a
3 design basis space, we're looking at the safety-
4 related, the safety functions that these have to
5 provide to meet the regulations.
6 I just want to make sure that there's a
7 distinction between those two types of review.
8 MR. SIGALA: This is John Sigala. I'm the
9 Chief of the Balance of Plant Branch.
10 I did also want to point out some other
11 things. I mean there's been a long history of
12 operating experience on instrument air. It started
13 back with Generic Issue 43. There was an OAD study
14 that was done on air system problems. That turned
15 into Generic Letter 88-14. We had all licensees go
16 out there and look at their systems, look at an
17 instantaneous loss of instrument air, a loss -- a
18 gradual loss of instrument air, an increase in air
19 pressure to see if that would cause failures of
20 components. Licensees went out and did that. We have
21 a Reg. Guide 1.68.3 which is initial testing for
22 instrument air systems.
23 GE, I believe, has committed to that in
24 their initial test program. That has them do this
25 testing when they build the plant to do a gradual

1 loss, an increase in pressure and then an
2 instantaneous loss.
3 We do look at operating experience. We
4 have issued Generic Letters, information notices on
5 these topics. We do take that into account when we do
6 our reviews. We do factor that into updates to the
7 SRPs. But we believe, if you go back to the maybe
8 earlier slide, the continuous monitoring of the air
9 quality, we believe prevents a lot of these -- or
10 allows these degradation issues to become aware. A
11 lot of the problems from operating plants were because
12 the instrument air systems were not properly taken
13 care of over long periods of time. You had corrosion
14 products build up. You had moisture problems. You
15 had desiccant filter issues, clogging up valves and
16 then when they would lose instrument air the valves
17 wouldn't shut.
18 I think these are all the issues that you
19 guys are concerned about and we are too. And I think
20 that the continuous monitoring of the air system, the
21 periodic testing in accordance with the ANSI standard,
22 those are all things that are built into our SRP as
23 ways that the systems are maintained so that you
24 minimize these kinds of effects from happening.
25 There was a research report that was done

1 a couple of years ago that looked at hey, it's been 20
2 years since we've issued Generic Letter 88-14. Have
3 we seen any operating experience since then, since
4 plants fixed the problems, have we seen any operating
5 experience that lends us to believe that we need to
6 issue another Generic Letter or what not. The
7 conclusions out of that was that that was not the
8 case, that we have not seen a resurgence of instrument
9 air problems and I guess the Staff has done a review.
10 We feel like this design, with the Reg. Guide 168,
11 initial testing, and the periodic looking at the
12 moisture content and the periodic testing, we believe
13 that this is adequate.
14 MS. CUBBAGE: I just want to briefly cover
15 an issue of emergency lighting. Since the
16 Subcommittee, we did get clarification from GE Hitachi
17 in an RAI response. The emergency lighting and the
18 remote shutdown area is fed from safety-related 72-
19 hour power supply in a similar arrangement to the main
20 control room.
21 We're reaching resolution on that issue
22 pending GE updating the ITAAC to include this item.
23 MEMBER BANERJEE: Is this UPS of batter
24 supply or what?
25 MS. CUBBAGE: Amar?

1 MR. PAL: Amar Pal, NRO/DE. Yes, these are
2 backed by UPS for 72 hours.
3 MEMBER BANERJEE: But what is the UPS
4 system?
5 MR. PAL: Uninterrupted full Power Supply.
6 MEMBER BANERJEE: What is it?
7 MR. PAL: Battery.
8 MEMBER BANERJEE: What kind?
9 MR. PAL: BRLA. Valve regulated lead acid
10 battery.
11 MEMBER BANERJEE: What?
12 MS. CUBBAGE: Valve regulated.
13 MR. PAL: Lead acid.
14 MEMBER BANERJEE: And these are similar
15 capacities to the existing lead acid system?
16 MS. CUBBAGE: A very large battery.
17 MEMBER CORRADINI: We needed you on this
18 Subcommittee. You would have had fun at this point.
19 MS. CUBBAGE: We did cover this at a
20 previous meeting and he's nodding his head. Our lead
21 electrical reviewer is not here, but --
22 MEMBER CORRADINI: Is there a GE person
23 that can --
24 MEMBER BANERJEE: I'm really asking is
25 there any qualitative difference between what we do

1 today. And I suspect that it does.

2 MS. CUBBAGE: The technology is different

3 in that these are the valve regulated batteries.

4 They're large batteries. Beyond that, I need to call

5 on GE.

6 MEMBER SIEBER: In a lot of plants today,

7 you have a light with an integral battery that's

8 plugged in if the power supply fails, the battery will

9 take over. It depends on if there's enough light in

10 the room or not, it turns on, if there isn't.

11 MR. UPTON: Amy, this is Hugh Upton with

12 GEH. I don't believe we have our experts here in the

13 electrical uninterruptable power supply system. So we

14 would have to defer that until we get the right

15 experts in.

16 MEMBER CORRADINI: At the time when we

17 were explained this and we quizzed them, we were

18 satisfied.

19 MEMBER STEKAR: Is there light at the

20 remote shutdown panels for --

21 MS. CUBBAGE: Yes.

22 MEMBER STEKAR: How you get it there, I

23 don't care.

24 Are the lights on for 72 hours?

25 MS. CUBBAGE: The lights are on. It's

1 powered by that --

2 MEMBER BANERJEE: I just wanted to double

3 check that the source of the light is there.

4 MEMBER STEKAR: The source of the light is

5 the source of everything else that's important in the

6 plant. If that's not there, there are big problems.

7 MS. CUBBAGE: And there is additional

8 detail in Chapter 8 of the design cert. document and

9 the Staff's safety evaluation that we briefed the

10 Committee on in the fall.

11 MEMBER CORRADINI: I can lend you my CD.

12 MEMBER BANERJEE: Please. Just this part

13 of the CD.

14 MS. CUBBAGE: There was some discussion

15 earlier on hydrogen water chemistry. I'd just like to

16 reiterate the Staff's position that current

17 regulations do not require applicants to implement

18 hydrogen water chemistry. I will note that the first

19 two COL applications referencing the ESBWR design

20 certification have selected hydrogen water chemistry.

21 We don't see any significant safety issues with

22 treating hydrogen water chemistry as an option to any

23 future applicant because of the selection materials.

24 They're resistant to degradation. They also, a key

25 point is the in-service inspection required by the

1 ASME code and that's all I plan to present on that.

2 MEMBER CORRADINI: But under NUREG 03-13,

3 wouldn't you have still have augmented inspection if

4 you didn't have hydrogen water chemistry, because you

5 wouldn't have two means of mitigation?

6 MS. CUBBAGE: We have Gregory Makar from

7 the Staff here.

8 MR. MAKAR: Hi. I'm from the Division of

9 Engineering, Component Integrity. Yes. That's true.

10 Our approach -- our safety concern in this area is the

11 leakage and structural integrity of the reactor

12 coolant pressure boundary. And our regulatory

13 approach here is the design and fabrication of the

14 reactor coolant pressure boundary and then we have --

15 in order to prevent rapid or sudden types of

16 degradation and inspection requirements are key to

17 that.

18 With respect to the reactor coolant, we

19 agree that with -- in terms of stress corrosion

20 cracking which is the concern here, that these -- this

21 combination of materials and the environment and the

22 stresses could create -- is susceptible to stress

23 corrosion cracking. And that we probably cannot pull

24 that, pull those -- that intersection apart

25 completely. And even going to hydrogen water

1 chemistry, it's not an on-off switch for stress
2 corrosion cracking. It is -- it's an engineer -- it
3 may represent an engineering threshold that allows us
4 to go to longer times, feeling that we can't have
5 stress corrosion cracking. But really with respect to
6 our safety concern, that trying to optimize the
7 materials and the augmented inspections and the code
8 required inspections are adequate to ensure that
9 integrity.
10 MEMBER BANERJEE: Let me ask a question
11 about the mixing of the hydrogen. This is a natural
12 circulation system, so if I recall, at some plants
13 there was a problem with how well the hydrogen mixed
14 in the downcomer, right, the feedwater injection and
15 stuff.
16 Are there any issues related to that which
17 occur in this system? I remember this occurred in
18 Forshmark and they asked me to evaluate how well it
19 mixed at one point. But does this happen in this
20 plant, the velocities are somewhat lower, I imagine.
21 Are there mixing issues?
22 MR. MAKAR: I'm sorry. I don't know the
23 answer to that.
24 MEMBER BANERJEE: How do they inject it?
25 MR. CAINE: This is Tom Caine from GEH.

1 It's injected in the feedwater and the example you
2 mentioned in the Swedish plant was really due to the
3 configuration of the feedwater sparger not getting a
4 full azimuthal distribution out into the reactor
5 annulus. My understanding is that the ESBWR is going
6 to have that good azimuthal distribution so that
7 shouldn't be an issue.
8 The feedwater is a pumped-driven system so
9 getting the feedwater into the downcomer flow should
10 be very similar to what happens today in the operating
11 plants.
12 MEMBER BANERJEE: Thank you. That deals
13 with it.
14 MEMBER ARMIJO: I would just like to make
15 one point. I agree with Amy's points that it's not a
16 regulatory requirement, but I do disagree with the
17 point that the ESBWR Class 1 and 2 materials are
18 resistant to stress corrosion, cracking, degradation.
19 They may be better than 304 or 304L, but
20 they're not immune. And a lot of testing, as well as
21 plant experience has shown even the 360 nuclear grades
22 can crack and have cracked in European plants, have
23 cracked in Japanese plants. And so that's just
24 factually wrong. That's just one element of
25 protection against stress corrosion, cracking. They

1 are better materials, but they're not immune. The
2 fabrication can undermine their immunity. Poor
3 fabrication can cause good material to be susceptible.
4 So again, I'm glad that the plants that
5 are looking seriously as ESBWRs are selecting hydrogen
6 water chemistry because then they have the benefits of
7 better materials, better fabrication, and good water
8 chemistry. That combination, I think, offers the
9 potential for a crack-free operation of these plants
10 with later benefits on inspection and everything else.
11 Finding and fixing cracks is a very poor
12 substitute to picking the right materials, the right
13 water chemistry and fabricating them properly. So I'm
14 glad that the actual operators that are looking at
15 this system are selecting this kind of water chemistry
16 and in time I would hope that the regulatory body
17 pushes that, even though you legally may not be able
18 to do it. I don't know.
19 MS. CUBBAGE: I understand what you're
20 saying and Bob Davis is at the mic here.
21 MR. DAVIS: I'm Bob Davis, and I'm the
22 Senior Materials Engineer that reviewed a lot of the
23 reactor coolant pressure boundary. And I just want to
24 note that NUREG 03-13 provides recommendations for
25 material selection, augmented inspections. This all

1 came out of the early BWR stuff. The materials that
2 GE is using are considered category A material. They
3 don't require -- they're not considered category A if
4 they hydrogen water chemistry. They're considered
5 category A materials. They don't require any
6 augmented inspections --
7 MEMBER ARMIJO: I thought you had to have
8 two.
9 MR. DAVIS: In the NUREG, what's category
10 A though, but not in category A.
11 MEMBER ARMIJO: I'm not too worried about
12 categories. I'm worried about physical resistance to
13 stress corrosion, cracking, and real conditions, not
14 what some category says. The testing data is out
15 there in the literature and the operational experience
16 in power plants is out there in the literature. I
17 think you're doing a disservice to your clients by
18 giving the impression that these materials, by
19 themselves are perfectly adequate. All you have to do
20 is wait around until they crack and then you find them
21 and fix them.
22 That's not the way to field the brand new
23 design that has a potential of being basically immune
24 from these problems if you take advantage of all the
25 tricks you've learned over the past 40 years.

1 MEMBER CORRADINI: Just to move on, I
2 think you see Sam's point for the first bullet or the
3 sub-bullet and it seemed a bit smudged. But I think
4 we need to go on --
5 MR. MAKAR: I agree. The staff agrees
6 with his comments on that and we intentionally did not
7 use the word immunity because we do not believe that
8 these -- and they may not be immune in hydrogen water
9 chemistry to irradiation-assisted stress corrosion,
10 cracking and it may give a false sense of security to
11 --
12 MEMBER ARMIJO: Right, but you've got to
13 agree that the combination of three independent
14 mechanisms to minimize risk is much, much more
15 powerful than any one by itself.
16 MS. CUBBAGE: But we have assured
17 ourselves that the safety issues are resolved and that
18 the regulations are met.
19 Craig Harbuck from Tech. Specs.
20 MR. HARBUCK: My name is Craig Harbuck.
21 I'm in the Technical Specifications Branch in the
22 Division of Construction, Inspection Programs. And I
23 understand you were wanting to talk about passive ECCS
24 and containment cooling surveillance requirements and
25 their frequencies.

1 We touched on it earlier in the GE
2 presentation. The systems that we're going to talk
3 about as it comes up are the Automatic
4 Depressurization System, the Gravity-Driven Cooling
5 System, the Isolation Condenser System, Passive
6 Containment Cooling System, and associated with those
7 are the EC/PCC Pools and I inadvertently left off the
8 Standby Liquid Control System.
9 We believe that the testing that's
10 specified in the technical specifications for these
11 systems is consistent with what testing is done on
12 similar-type components and operating plants. It's
13 consistent with the standard tech specs. And it's
14 mostly based -- there are other considerations, but
15 engineering judgment being a consideration for
16 frequencies, and to facilitate discussing these,
17 there's four slides that list by focusing on the
18 frequency what the various tests are and the very
19 general language and what systems they apply to.
20 Another thing to point out is that many of
21 the components in these systems are also subject,
22 particularly valves, are subject to in-service testing
23 and so we can talk through in-service testing also.
24 But in particular, squib valve testing is included.
25 The ICS return line valve testing, ICS system

1 initiates by opening a couple of nitrogen motor-
2 operated valves. And those valves have to be struck
3 tested quarterly. And then GDCS injection line check
4 valves are by virtue of test connections on the
5 injection lines are able to operate the check valves
6 to verify they function properly. But that comes
7 under the in-service testing.
8 There was some discussion earlier about
9 the non-condensable gas venting. The only thing I'd
10 like to point out there, other than the GDCS lines is
11 that the isolation condenser system and PCCS
12 condensers all have provisions for either
13 automatically or upon actuation venting of any
14 noncondensables that might occur as part of the
15 design. And all that venting is done to the
16 suppression pool.
17 And the last --
18 MEMBER CORRADINI: Where is the venting
19 done from? Maybe I forgot.
20 MR. HARBUCK: Well, there is -- the ICS
21 system has vents from both the high and low parts.
22 And in the PCCS, I believe the venting is from the
23 lower drum.
24 MEMBER CORRADINI: Lower drum into the wet
25 well?

1 MR. HARBUCK: Yes, the connection -- well,
2 no. The lower drum of the condenser and then the
3 water drains through the GDCS pool and the gas vents
4 to the suppression pool.
5 MEMBER CORRADINI: But when you got to the
6 vent -- I guess maybe -- when you said venting, I
7 thought you were talking about not during operation,
8 but during to clear it. So I seem to remember this is
9 a small point. We can talk about it in a side
10 question. I just wanted to understand for venting
11 where it was done. So let's just move on.
12 MR. HARBUCK: All the venting goes to the
13 suppression pool.
14 MEMBER CORRADINI: Okay.
15 MR. HARBUCK: And then this other issue,
16 resolution of bracketed items, we had a question early
17 on in the review about to clarify what was meant by
18 bracketed information in the tech specs and in the
19 bases. And there was response that was implemented in
20 Revision 3 which indicated that items that were in
21 square brackets would be items that might be
22 contenders for COL information items.
23 And if they were curly brackets it would
24 be stuff that was to be settled during the design
25 certification. Well, in Rev. 4 that changed and there

1 was this shift in using curly brackets to also mean
2 items that potentially could go to -- be completed by
3 a license holder and so we've had some discussions
4 about that and where we're --
5 MEMBER SIEBER: You should have used this
6 kind.
7 MR. HARBUCK: Where we're going on this is
8 that we would just use the square brackets. We would
9 use the square bracket for both kinds of information,
10 whether it would be provided during the COL
11 application review or after the license was issued and
12 then in the tech specs we would have reviewers' notes
13 which would explain how the brackets would be -- how
14 they would be resolved or how -- what the applicant or
15 the licensee had to do to resolve the provided
16 information.
17 And those brackets that are for the COL
18 applicant, we would prefer that they actually put
19 something in the brackets, not have a set of brackets
20 in empty white space. And holder items, license
21 holder items indicated by brackets would need to be
22 tied to design acceptance criteria.
23 An example would be instrumentation
24 settings tied to instrumentation system design, detail
25 design.

1 So just looking at this list, the
2 frequencies that you see are fairly typical for what
3 we would find in comparable systems in the --
4 MR. NAMARA: This is Mike Namara from the
5 Branch for Tech Spec. and I just want to clarify that
6 the bracketed item issue is still an open issue
7 between the Staff and GEH with regards to which items
8 might be going forward as COL holder items or going
9 forward as COL applicant items.
10 The preference of the Staff would be to
11 resolve or have most of these addressed on the design
12 certification stage.
13 MEMBER CORRADINI: I'm going to let you
14 guys sort out the bracket stuff.
15 (Laughter.)
16 MEMBER SIEBER: When we are all done,
17 there won't be any.
18 MS. CUBBAGE: It's what gets filled in
19 when. If it's part of the certification and part of
20 issuance of the license or something that needs to be
21 filled in after they've constructed the plant and the
22 equipment, and finished the design of the
23 instrumentation and pick set points.
24 MR. HARBUCK: On the first slide of this
25 four slide set, I just would add that the standby

electric control system for a 24-hour frequency also has for the accumulators which are pressurized to check the volume, temperature, and pressure in a 31-day frequency to check concentration of the solution.

MEMBER CORRADINI: So remind me, the second one, and maybe I just don't understand the -- so every day RPV --

MR. HARBUCK: I need a little more explanation for that one.

I didn't distinguish between operating modes and shutdown modes, but the second -- that second one is for shutdown modes.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: To make sure your mode 5 or beginning mode 6, you -- if you have some reason -- you've lost decay heat removal and the GCS needs to inject, you've got a vent path.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: And then the pool inventory you see is repeated, but the second one is for shutdown situation.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: And then on the next page there's also a standby electric control system, the valve position verification and the squib firing

1 circuit continuity check.

2 On the last one on the second page, the

3 automatic valve actuation, this typically doesn't

4 involve actually -- changing the valve position, you

5 test everything but the valve position.

6 MEMBER CORRADINI: We're doing fine.

7 MS. CUBBAGE: We're on 13 still?

8 MR. HARBUCK: I'm on 15.

9 MS. CUBBAGE: Fifteen.

10 MR. HARBUCK: Fifteen.

11 MEMBER CORRADINI: Before you go to 15,

12 can we talk about 14 for a minute?

13 MR. HARBUCK: Sure.

14 MEMBER CORRADINI: So 24 months, verify

15 valve locked open. I understand that.

16 Twenty-four months, SRV Manual Actuation.

17 So you would go through on the non-squib SRVs and

18 cycle them on that frequency. So all would be cycled

19 within on a two-year basis. Do I understand that

20 correctly?

21 MR. HARBUCK: Which one are you looking

22 at?

23 MEMBER CORRADINI: Page 14, second one.

24 MR. HARBUCK: The second one.

25 MEMBER CORRADINI: GEH can correct. I've

1 got them.

2 MR. HARBUCK: You mean page 16?

3 MEMBER CORRADINI: Yes.

4 MR. HARBUCK: Okay, what this is is that

5 there's four solenoids on each valve.

6 MEMBER CORRADINI: That page, second line.

7 MR. HARBUCK: Right. And there's four

8 solenoids in each valve, so every 24 months they cycle

9 all the valves, but using one of the solenoids and

10 they move through the different solenoids to actuate.

11 I was confused. That should be 96 months to indicate

12 the total time between testing each solenoid because

13 there's three from the normal actuation system and

14 then there's a diverse actuation system which is the

15 fourth solenoid.

16 MEMBER CORRADINI: Thank you. And the

17 verify drain lines to GDCS pool.

18 MR. HARBUCK: The GDCS system has no

19 valves in it. It's a straight shot from the dry well

20 through the tubes and back down to the -- draining

21 back down to the GDCS. And there's also a vent line

22 to the suppression pool. So there's a requirement --

23 and there's six of these condensers. So you check one

24 every outage so that would be 12 years between this

25 and it's basically just verifying there's no

1 obstruction.

2 MEMBER CORRADINI: Just to go back to GEH,
3 you already said the GDCS pool line is six inches.
4 The vent lines and suppression pool and flow path
5 through condenser -- what are those lines again? I
6 have forgotten and I apologize.

7 MR. UPTON: This is Hugh Upton with GEH.
8 The PCCS vent line is a 10-inch vent line and this is
9 what we're talking about is the vent line coming from
10 the PCCS heat exchanger to the suppression pool.

11 MEMBER CORRADINI: To the suppression
12 pool. And then -- okay, thank you very much.

13 MR. HARBUCK: The last page, you'll see
14 the isolation condenser heat capacity verification.
15 There's four condensers. There's four condensers on
16 staggered test bases. You do one -- each one gets
17 tested every eight years.

18 And then the 10-year, the verify flow
19 paths unobstructed. We discussed that one earlier and
20 then this 10 year on the verify vent path from the
21 pools unobstructed. This is the path where the water
22 evaporating to exit the --

23 MEMBER ARMIJO: Are those verifications
24 very difficult to perform?

25 MR. HARBUCK: There is a number of ways

1 you can do the verifications. I would have to defer
2 to GE to offer an explanation or more description
3 about that.
4 MEMBER ARMIJO: Somebody just tell me. Is
5 it every 10 years? Because it's very difficult to
6 perform or it's every 10 years because that's the
7 general practice on things like this?
8 MR. HARBUCK: Again --
9 MEMBER ARMIJO: But if it was easy to
10 perform would you do it more often?
11 MR. HARBUCK: Not necessarily.
12 MEMBER BANERJEE: Are these empty lines
13 basically?
14 MR. HARBUCK: For the ECCS line, they're
15 basically empty, except for a sealed line down in the
16 --
17 MEMBER CORRADINI: So let me be
18 provocative to get an answer out of GEH. So if you're
19 doing everything else in two years, why are you
20 waiting ten years for this one? That's where I
21 thought Sam was going with it.
22 Is it a matter of difficulty? What it isa
23 matter of because you're changing the inspection
24 frequency of a factor of five with two different sets
25 of lines.

1 MR. WILLIAMSON: Dan Williamson, GEH. I
2 lost track of exactly which one we're talking about.
3 MEMBER CORRADINI: We're looking at page
4 14 and page 15. And page 14 if I understand it,
5 you're verifying drain lines to the GDCS unobstructed
6 and line suppression pool every two years. And on
7 page 15, you're verifying flow paths unobstructed like
8 the GDCS I assume to the vessel and from pools
9 unobstructed every ten years. And so Sam's first
10 question was how hard is it? And then next follow-on
11 question will be so if it ain't so hard, why are you
12 doing it five times longer?
13 MR. WILLIAMSON: The frequency, in fact,
14 the 24-month frequency is staggered for each PCCC, so
15 it's essentially you do one of them every two years.
16 You repeat that same one 12 years.
17 MEMBER CORRADINI: Okay.
18 MR. WILLIAMSON: It's very similar to the
19 10-year frequency.
20 MEMBER CORRADINI: Okay.
21 MEMBER BANERJEE: How do you do this?
22 MS. CUBBAGE: Which one?
23 MEMBER BANERJEE: Verify the line is
24 unobstructed.
25 MR. HARBUCK: there is in-service testing,

1 there's pressure testing.

2 MEMBER BANERJEE: Is it a flow rate that

3 you look at? How do you know it's unobstructed. The

4 word unobstructed is interesting.

5 MR. HARBUCK: I would have to defer to GE

6 as exactly how it's done, but I suppose it would have

7 to be some --

8 MEMBER CORRADINI: So let me just take an

9 extreme case. I'm wondering where Sanjoy is going,

10 but my extreme case is the oil company sends down a

11 little beastie that goes and looks at it.

12 MEMBER BANERJEE: It's a pig.

13 MEMBER CORRADINI: I couldn't remember

14 what it was called, a pig. So my question is what's

15 your equivalent of a pig to determine it's

16 unobstructed?

17 MEMBER BANERJEE: And they have smart pigs

18 as well.

19 MEMBER CORRADINI: They're smart pigs.

20 They're not stupid pigs, that's true.

21 MS. CUBBAGE: Other than firing off the

22 squib valve and --

23 MEMBER CORRADINI: I am sorry to be so --

24 this is -- you're kind of back to the overall thing

25 that we're just kind of mulling over about checking

1 passive systems.

2 MR. DEAVER: This is Jerry Deaver with

3 GEH. There's any number of ways that could be used.

4 What we're suggesting right is that flowing of the

5 lines is one way possibly; flushing visual inspection,

6 what might include a bore scope kind of inspection

7 which would be sending small cameras down the line to

8 take a look.

9 A lot of it depends on geometry and in

10 some cases that would be very difficult.

11 MEMBER BLEY: You have not decided yet how

12 you're going to recommend this be done?

13 MR. DEAVER: We haven't really gotten into

14 all the specifics, but obviously, as we design the

15 actual pipe runs and so forth, we need to keep this

16 under consideration.

17 MEMBER BLEY: Okay.

18 MEMBER CORRADINI: That helps. So we'll

19 be talking. Thank you.

20 MR. HARBUCK: Is there anything else that

21 you want to ask about either the surveillance or the

22 in-service testing?

23 Conclusions. First one I believe I've

24 already mentioned. And we're pretty -- we've

25 concluded that what's been proposed is acceptable for

1 ensuring we're meeting the LCOs. And then the next
2 slide is a repeat from the previous presentation, but
3 we've got a number of issues remaining at this time
4 and so we haven't reached an overall conclusion about
5 the acceptability of the tech specs. We also are
6 dependent upon what happens in other chapters for so
7 many of our issues.
8 That's it for me.
9 MS. CUBBAGE: And that overall conclusion
10 does apply across the board to these chapters. They
11 all do have some degree of open items. We'll be
12 presenting to the Committee at the end stage, when we
13 have a final safety evaluation. It addresses all of
14 the open items. We'll brief that to the Subcommittee
15 and then to the full Committee.
16 MEMBER CORRADINI: Are there questions by
17 the Members?
18 MEMBER BLEY: Yes. Amy, this isn't an
19 instrument air question, but I'm going to pull on a
20 thread that came from there. I'd like to understand
21 the process you folks use when a new DCD revision
22 comes out and it was that cartoon issue that comes to
23 mind to look at new drawings that are issued for
24 systems and if there's anything different that isn't
25 fully explained in the text, does that generate a

1 question back about why this change and what does it
2 affect?
3 MS. CUBBAGE: In this particular case the
4 system did change between Rev. 3 and Rev. 4.
5 MEMBER BLEY: No, but I mean in general.
6 MS. CUBBAGE: In general --
7 MEMBER BLEY: When the new rev. comes out
8 does somebody compare these and say oh, this is a
9 little different.
10 MS. CUBBAGE: Yes.
11 MEMBER BLEY: Why is it?
12 MS. CUBBAGE: We do look at the new DCD
13 revisions in detail. We ensure that it has not
14 invalidated any of the conclusions that we had drawn
15 previously and we'll base our conclusions in the final
16 DCD revision that comes in.
17 MEMBER BLEY: So for every system you're
18 looking at, you do those.
19 MS. CUBBAGE: That's right. To facilitate
20 that, GE has been providing us with the document that
21 shows the changes between one rev. and the next rev.
22 MEMBER CORRADINI: So there's a tracked
23 change.
24 MS. CUBBAGE: We don't have to go word by
25 word, but again that is our responsibility to ensure

1 that the SED is acceptable at the end.

2 MEMBER CORRADINI: So there's some sort of

3 track changes.

4 MR. HARBUCK: They provide a change list.

5 MEMBER CORRADINI: Ah.

6 MR. HARBUCK: And there's usually an

7 explanation of why the change and oftentimes it's

8 related to our questions.

9 MEMBER CORRADINI: Okay.

10 MEMBER BLEY: In the second -- I had two.

11 They both came from the same source. I appreciated

12 the discussion on the instrument air problems and the

13 insights that were there in the staff, but listening

14 to the interplay on all these systems, is there a

15 place or a process that that kind of knowledge of

16 operating experience comes -- where does that come

17 into this review to make sure that the reviews

18 conducted by individuals who might not be so familiar

19 with that are taking those things into consideration,

20 as least to the extent it's important?

21 MS. CUBBAGE: As John Sigala indicated, we

22 do periodically assess our Standard Review Plan as we

23 did this about a year ago now and when we do that, we

24 factor in any experience that has happened since the

25 last SRP updates.

1 MEMBER CORRADINI: So it's through the
2 SRP.
3 MS. CUBBAGE: Through the SRP and in the
4 interim the Staff also has an obligation to look at
5 all of the Generic Letters, bulletins, generic safety
6 issues, etcetera, that have been issued by the Staff
7 to ensure that they've been properly incorporated by
8 the applicant into their design.
9 And you will be seeing at the final SER
10 stage in our Chapter 20, we will have a listing of all
11 the Generic Letters and bulletins and other generic
12 issues that the Staff looked at and it will show where
13 in the staff's evaluation that it has been addressed.
14 MEMBER CORRADINI: I appreciate that.
15 MEMBER BANERJEE: I just have a question
16 about the equalization line. This was back to the
17 presentation actually, I'm sorry.
18 Do you have a procedure to verify that the
19 equalization line is unobstructed?
20 MS. CUBBAGE: The equalization line --
21 MR. HARBUCK: It's included in the
22 surveillance requirement to verify the lines are
23 unobstructed.
24 MS. CUBBAGE: It's part of the GDCS spec.
25 MEMBER BANERJEE: It's part of the GDCS

1 spec.

2 MR. HARBUCK: Right.

3 MEMBER BANERJEE: And the condensate drain

4 line is part of the --

5 MS. CUBBAGE: The condensate drain line

6 for the isolation condenser? That would be part of

7 the isolation condenser.

8 MEMBER BANERJEE: So there is a procedure

9 in place to validate those are unobstructed.

10 MR. HARBUCK: Well, every two years you

11 operate the ICS condenser so you verify performance of

12 the whole.

13 MEMBER BANERJEE: How about the

14 equalization line? How do you look at that?

15 That's quite a trick, I would think.

16 MS. CUBBAGE: They would look at the GDCS

17 objection line.

18 MEMBER BANERJEE: Okay. Unspecified as

19 yet.

20 MEMBER ABDEL-KHALIK: Mr. Chairman, I'd

21 like to express my personal concern regarding the

22 process by which this piecemeal chapter by chapter

23 review is being conducted. The time line of scheduled

24 pressure which has necessitated the use of this

25 piecemeal process are no different, in my view, than

1 plant operators whose culture emphasizes production
2 over safety.
3 Such a culture causes the applicant to
4 continually justify minimum standards and present
5 incomplete analyses, rather than perform and present
6 high quality complete analyses that withstand the
7 scrutiny of a thorough review.
8 I hope that at the end of the process we
9 will have the opportunity to review this application
10 in total rather than a piecemeal, incomplete,
11 inadequate fashion.
12 Thank you.
13 MS. CUBBAGE: I appreciate your comment
14 and I'd just like to point out that we've taken this
15 approach in order to engage the Committee early and
16 receive early feedback, not in any way to try and rush
17 this review or to address any schedule pressures.
18 We will be coming to the Committee with a
19 comprehensive complete safety evaluation at the end of
20 the process.
21 MEMBER CORRADINI: Can I just clarify?
22 Said, your point is that you would rather have seen it
23 with all the RAIs settled and looked at the complete
24 product.
25 MS. CUBBAGE: The concern on our part with

1 doing that would be that an issue might be raised by
2 the Committee because you certainly all raised very
3 good questions and the opportunity to address them at
4 the end is much more challenging when the design is at
5 a much later stage. There's more opportunity for your
6 issues to be addressed at this stage. It certainly
7 doesn't preclude you from raising issues later.
8 MEMBER ABDEL-KHALIK: But when an issue is
9 raised I think it would be much more beneficial if we
10 revisit that particular issue after the applicant has
11 responded to the RAIs and the appropriate analyses had
12 been completed.
13 MEMBER MAYNARD: I don't think we're being
14 asked to approve these chapters. What we're really
15 being asked to do is to make sure we have the right
16 issues that are being addressed. If there's any more
17 to be carried out, but we're not being asked to
18 approve anything at this point.
19 MS. CUBBAGE: You're absolutely right.
20 We're looking for that early feedback and education
21 from the Committee that if you have any issues that
22 are not -- were not engaged in GE-Hitachi on at this
23 time we'd like to know about those that we can address
24 them. We're looking for the Committee's final
25 approval at the end when we have a final safety

1 evaluation.

2 MR. SHUABI: Let me add to that. This is
3 Mohammed Shuabi of the Staff. We had a decision to
4 make about a year ago and the decision was do we want
5 to wait another year, two years, three years before we
6 start engaging the Committee on the design
7 certification at the point to where maybe we would be
8 -- where you want us to be.

9 We felt that it would not be in our best
10 interest to wait until then to come and start briefing
11 you on what we're doing in this. We wanted to come
12 here and present these chapters, present to you what
13 we're doing, present to you the open items that we've
14 identified and we're coming and telling you that these
15 are the open items that we, the Staff, are pursuing.
16 And if you have any additional open items, we're
17 looking to get that into our review process so that we
18 can address that. And you've had your questions and
19 we've taken those back and we've actually asked RAIs
20 as a result of these interactions and I actually think
21 it's been a very good way to do it.

22 The challenge, I think, and maybe at least
23 a little bit of frustration is sometimes we have to
24 say this topic or that topic, it's addressed in a
25 different chapter and then you come back with comments

1 about well, how do these link together? I think when
2 we come back to you at the final NCR stage and we have
3 the whole consolidated safety evaluation, you might be
4 able to see how the whole thing fits together. But at
5 this point in time, I did not want to wait. We did
6 not want to wait another year, two years, before we're
7 here for the first time talking to you about what
8 we're doing, how we're doing this, what issues we're
9 raising and to get your insights and your input.
10 So we valued interactions with you early
11 in the process so that we can get your input and I
12 hope that that was beneficial to you. It was
13 beneficial to us. And we really did take your
14 comments back and we're trying to address the ones
15 that we believe need to be addressed.
16 MEMBER ABDEL-KHALIK: I think it's just a
17 matter of balance as to where the appropriate point,
18 especially when issues are revisited.
19 MR. SHUABI: We agree.
20 MS. CUBBAGE: There's an efficiency issue
21 and we didn't want to waste your time. We feel at
22 this point that it's beneficial to hear any of your
23 comments and concerns as early as possible.
24 MR. SHUABI: We really did think hard
25 about this and we consulted with the ACRS Members and

1 staffers to make sure that this is a workable process
2 and we said we want to try this. So we're trying it.
3 I guess I'll defer to the Committee in
4 terms of whether they'd like to stop and for us to do
5 it differently.
6 MEMBER CORRADINI: Well, I think we'll
7 probably have to discuss this. I wouldn't say we're
8 going to stop talking about this point, but we can
9 stop at this moment about this. I think we're going
10 to come back to it. I think the first interim letter
11 specifically was crafted so that we didn't commit to
12 anything, but we raised concerns. And I think if
13 there is a second letter, it will be crafted
14 similarly.
15 MS. CUBBAGE: And we understand that and
16 that was the expectation.
17 MEMBER CORRADINI: We see where the Staff
18 is coming from on this. I appreciate them giving us
19 a heads up and I also appreciate GEH for the same
20 things.
21 MEMBER SIEBER: I think the design is more
22 flexible. As more time goes on, the less flexible it
23 becomes and therefore things, our concerns that are
24 raised now are far more easily addressed than they
25 would after General Electric does a lot more

1 engineering work and it becomes financially
2 prohibitive to make major changes.
3 So I think there is an advantage doing a
4 pre-review like we're doing as long as we get the
5 opportunity in the end, the entire GCD application.
6 MR. KINSEY: This is Jim Kinsey from GEH.
7 I guess I'd just like to echo that same position. We
8 were trying this based on dialogue with the ACRS early
9 on and with the NRC staff. We're trying a new and
10 different process here, working to get your inputs and
11 issues on the table early. Again, we can accommodate
12 a more comprehensive and succinct resolution to many
13 of those issues, the earlier in the process we're
14 aware of them. And we recognize that that brings some
15 frustrations with it and it takes a lot of resource to
16 do these Subcommittee and follow-up full Committee
17 meetings, but it's been very, very valuable to us at
18 GEH and I think the process is working. Again, it
19 takes some level of effort, but it's been very
20 beneficial to us as we proceed through the remainder
21 of the design certification process.
22 And as Amy mentioned, we do plan to or
23 will be required to come back around with the full SE
24 at the back end of the process and hopefully we'll
25 have addressed all of your issues and concerns at that

1 point, but we're certainly willing to listen to any
2 new or different ones that may be identified at that
3 time.
4 MS. CUBBAGE: And one last note to just
5 put in perspective where the Staff is at in the
6 process.
7 We had issued a total, at this point of
8 just over 3,700 RAIs. At this point, 2,800 are
9 resolved, so that's three-quarters. And so I think
10 the timing is such that we do have a lot of issues
11 that have been resolved.
12 MEMBER BANERJEE: When do we see the final
13 SER?
14 MS. CUBBAGE: The final SER, we're
15 actually currently reassessing the schedule for that
16 and I would estimate that it won't be in this calendar
17 year.
18 MEMBER BANERJEE: It will be?
19 MS. CUBBAGE: Will not.
20 MEMBER CORRADINI: You won't get a
21 Christmas present.
22 MS. CUBBAGE: You won't be getting a
23 Christmas present, but we will be following up with
24 your -- the ACRS Staff to make sure those interactions
25 are scheduled.

1 MEMBER CORRADINI: We can discuss that, I
2 think in the context of when we start -- when we
3 discuss the letter because you're going to hear about
4 potential outgoing meetings and how to schedule that.
5 MS. CUBBAGE: Right, our near-term concern
6 would be scheduling the next Subcommittee meetings on
7 the SER with open items. We do have a couple of
8 chapters to finish before we're completed with this
9 SER with open items cycle.
10 MEMBER ARMIJO: When will we see the final
11 DCD?
12 MS. CUBBAGE: GE-Hitachi is going to be
13 submitting a revision to the DCD, DCD Revision 5 at
14 the end of May and their intent is that that would be
15 the final rev. that we're basing our SER on. And of
16 course, the staff would need to review that rev. and
17 come to that conclusion.
18 MEMBER SIEBER: They would like that.
19 MS. CUBBAGE: They would like that. It
20 will be here at the end of May.
21 MEMBER CORRADINI: Mr. Chairman, on time,
22 and on budget. Back to you.
23 CHAIRMAN SHACK: On time.
24 MEMBER CORRADINI: This is the new world.
25 I can spin it any way you want.

1 (Laughter.)

2 CHAIRMAN SHACK: We'll take a 15-minute

3 break and then we'll teach Professor Corradini how to

4 tell time.

5 (Laughter.)

6 (Whereupon, at 3:42 p.m., the meeting was

7 concluded.)

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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

Docket Number: n/a

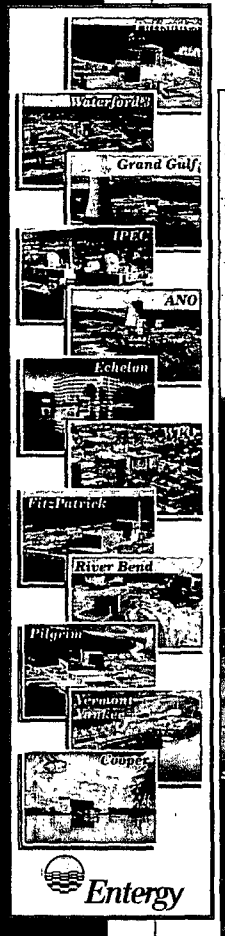
Location: Rockville, MD

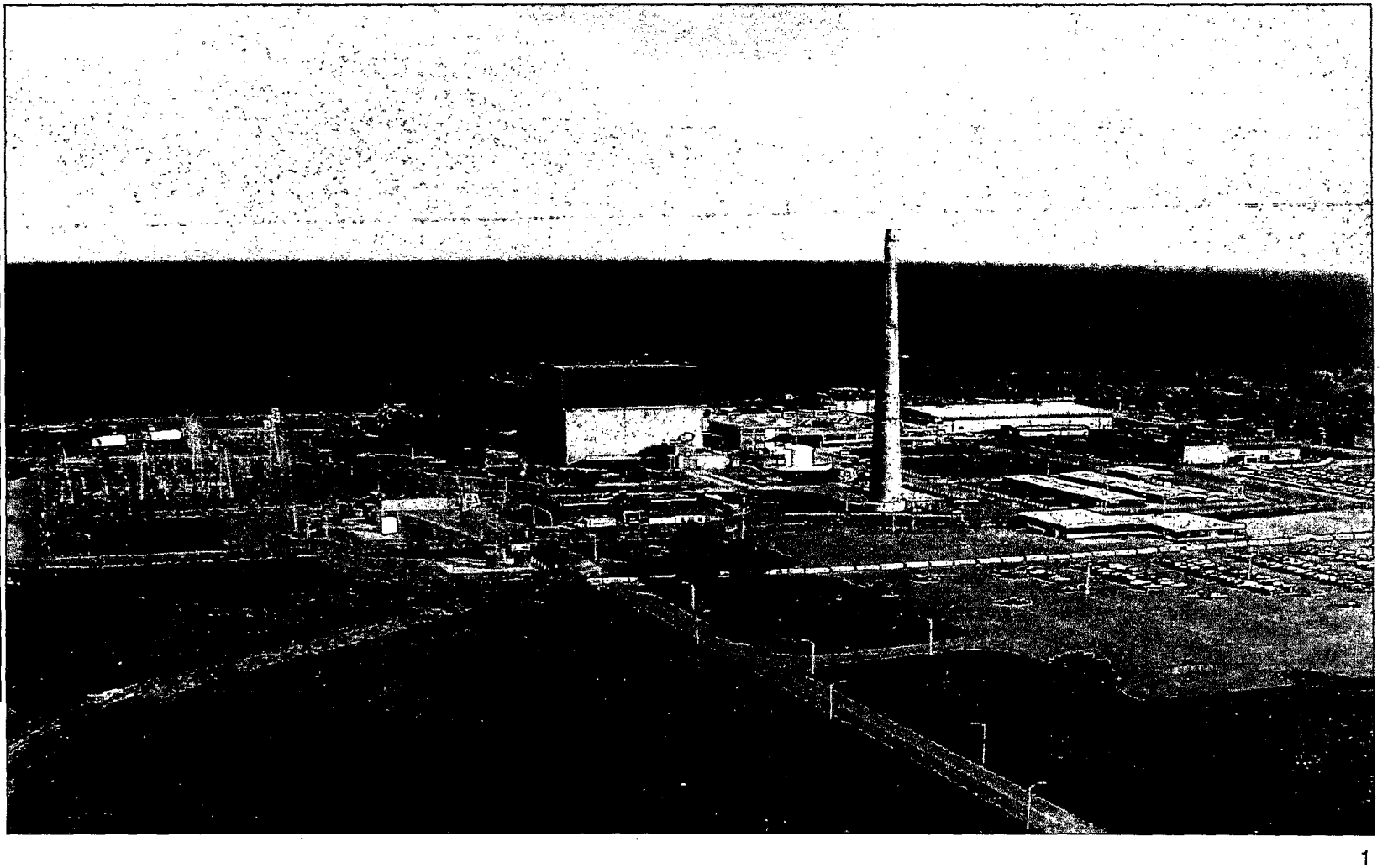
were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate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

Eric Hendrixson
Official Reporter
Neal R. Gross & Co., Inc.

James A. FitzPatrick Nuclear Power Plant

ACRS License Renewal Presentation
March 6, 2008

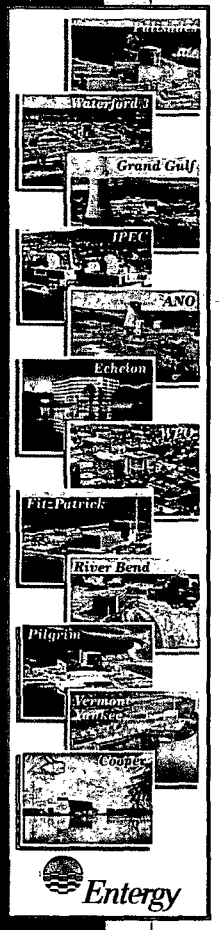




James A. FitzPatrick
Personnel in Attendance

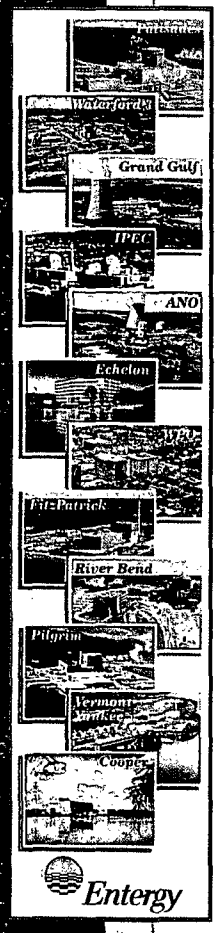
Pete Dietrich	Site Vice President
Brian Finn	Site NSA Director
Garry Young	Manager, Business Development
Steve Bono	Director of Engineering
Joe Pechacek	Manager, Programs & Components Engineering
Alan Cox	Technical Manager
James Costedio	Licensing Manager
Rick Plasse	Licensing Lead
Larry Leiter	Technical Lead
Tom Moskalyk	Structural Lead
Aturo Smith	ISI Engineer

Agenda



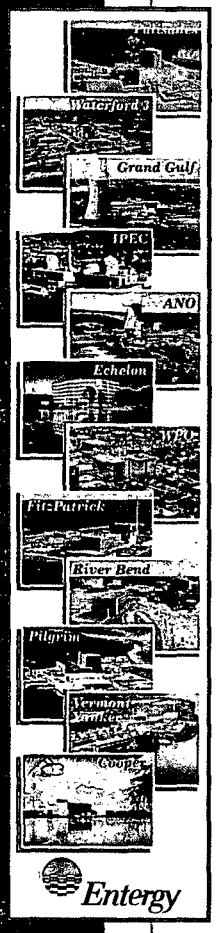
- Background
  - Site Description
  - Licensing History
  - Major Plant Improvements
  - Plant Performance
  - License Renewal Project
- Presentation Topics
  - Torus Monitoring
- Questions

JAFNPP Site Description



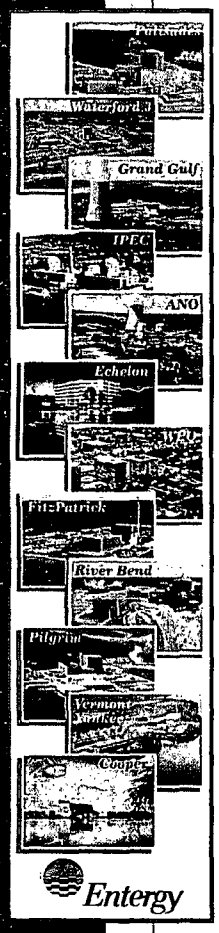
- General Electric (NSSS & TG), Stone & Webster (AE and Constructor)
- BWR-4, Mark I Containment
- 2536 MWt Thermal Power; ~ 881 MWe
- Once-through Cooling from Lake Ontario
- Staff Complement: Approximately 650

JAFNPP Licensing History



Construction Permit	May 20, 1970
Operating License	October 17, 1974
Commercial Operation	July 28, 1975
Uprated Power License (4%)	December 6, 1996
License Transfer to Entergy	November 21, 2000
LR Application Submitted	July 31, 2006
Operating License Expires	October 17, 2014

Major Improvements

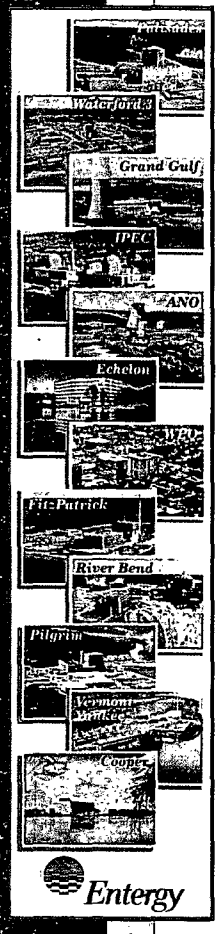


1978 – 1983	Mark I Containment Modifications
1988	Hydrogen Water Chemistry
1989	Zinc Injection
1990	Power Uprate Equipment Upgrades
1998	ECCS Suction Strainers Replaced
1999	Noble Metals Application
2004	LP Turbine Rotor Replacement
2004	Noble Metals Application 2
2006	HP Turbine Rotor Replacement
2006	Offgas Condenser Replacement
2006	HPCI Discharge Exhaust Sparger Added

JAFNPP Plant Status

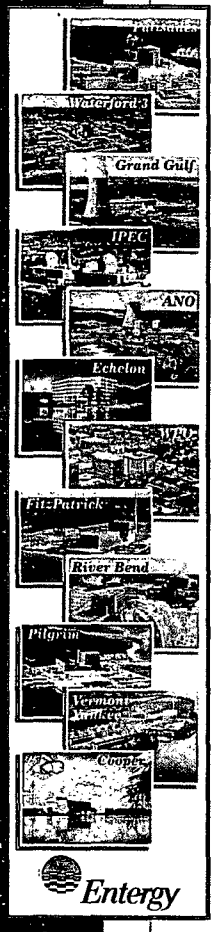
- Current Plant Status
- Outage Summary – Sept 2008
  - Outage items of interest
    - Main Transformer Replacement
    - Core Spray Motor Replacement
    - 345KV Breaker Replacement
    - Screenhouse Upgrades

JAFNPP License Renewal Project



- LRA prepared by experienced, multi-discipline Entergy team (utilized corporate and on-site resources)
- Incorporated lessons learned from previous applications
- Peer review conducted
- LRA internal reviews (Safety Review Committees and QA)
- All comments resolved prior to submittal

JAFNPP License Renewal Project



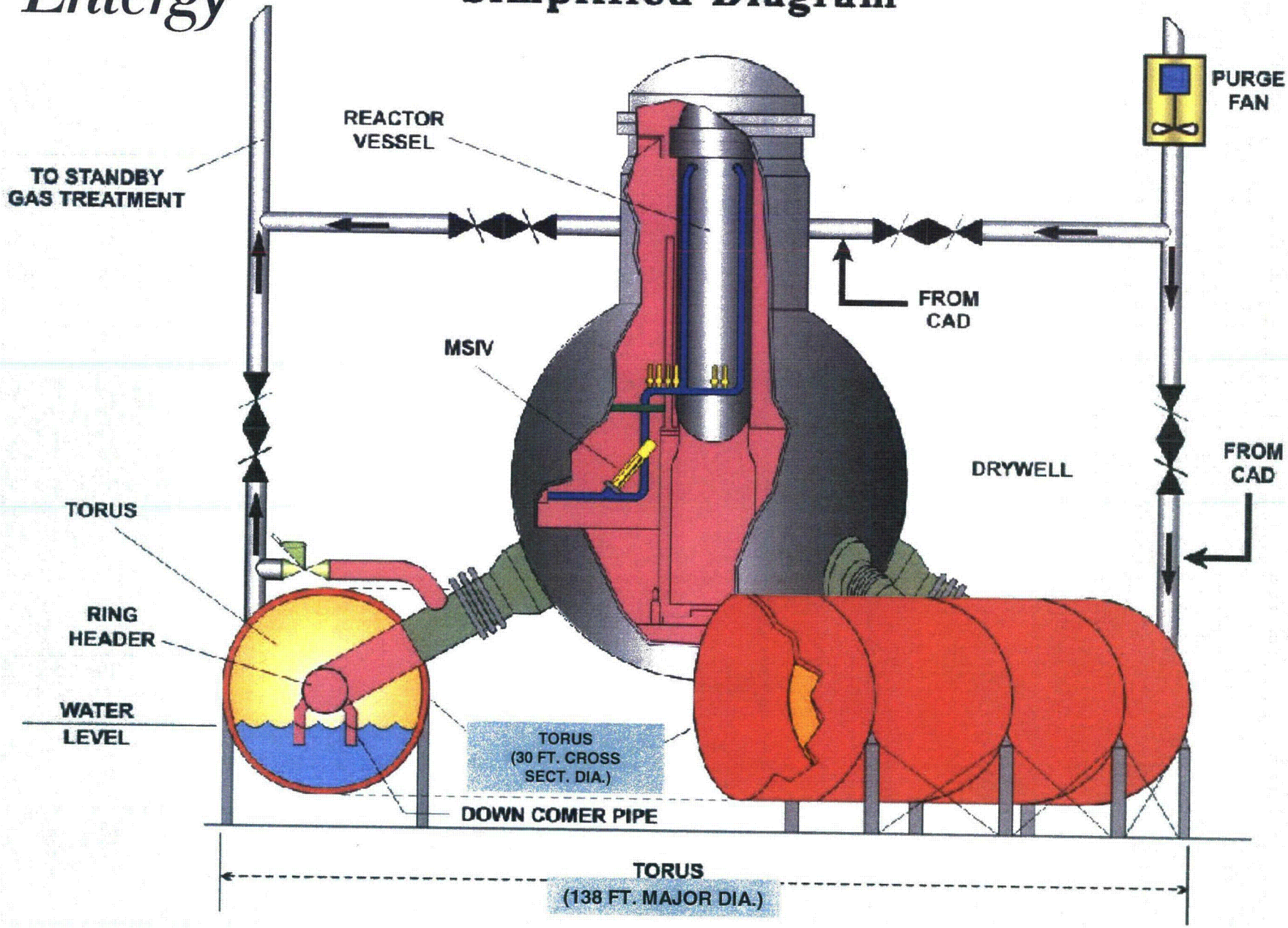
- Application Evaluated with GALL Revision 1
- License Renewal Commitments
- 36 Aging Management Programs

JAFNPP License Renewal Project

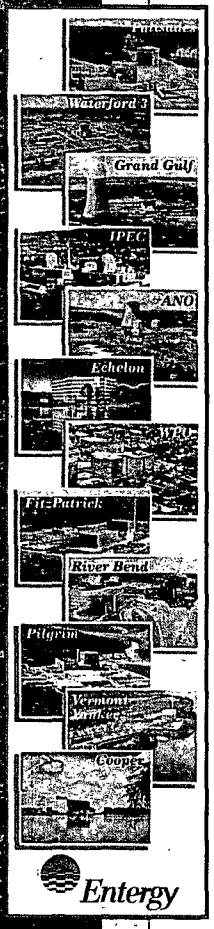
- Draft SER Issued July 2007 with 2 Open Items
  - Open Items – 2
    - Reactor Vessel Fluence
    - Environmentally Assisted Fatigue
  - Confirmatory Items – None
- Final SER Issued January 2008
  - All open items resolved

Entergy

Primary Containment System Simplified Diagram



James A. FitzPatrick

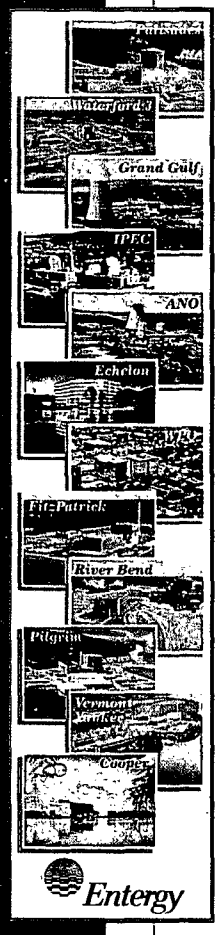


Torus Monitoring

Torus Monitoring

- JAF Containment Inservice Inspection (CII) Program implements IWE provisions
- ASME Code Category E-A Requirements (Containment Surfaces)
  - CII Program is performed in accordance with ASME Section XI 2001 Edition / 2003 Addendum

Torus Monitoring



- Inspection scope and frequency is in accordance with Table IWE-2500-1
  - Accessible Surface Areas – General Visual
    - Once Every Period
  - Wetted Surfaces of Submerged Areas – General Visual
    - 100% Once Every Interval
  - BWR Vent System – Accessible Surface Areas
    - 100% Once Every Interval

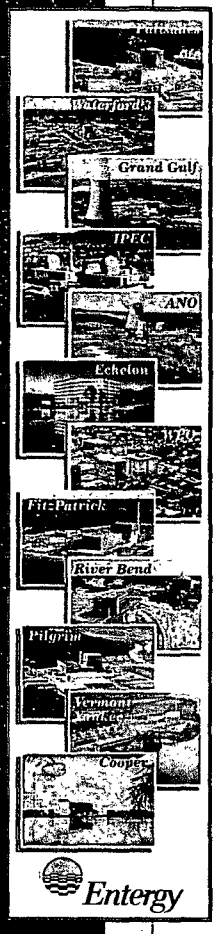
Torus Monitoring

- Inspection scope and frequency is in accordance with Table IWE-2500-1
  - Moisture Barriers – General Visual
    - 100% During Each Inspection Period
  - Containment Surface Areas – Detail Visual
    - Visible Surfaces 100% of surface areas Identified by IWE-1242
  - Surface Area Grid – Ultrasonic Thickness
    - 100% of minimum wall thickness locations each inspection period established in accordance with IWE-2500(b)(3) and IWE-2500(b)(4).

Torus Monitoring

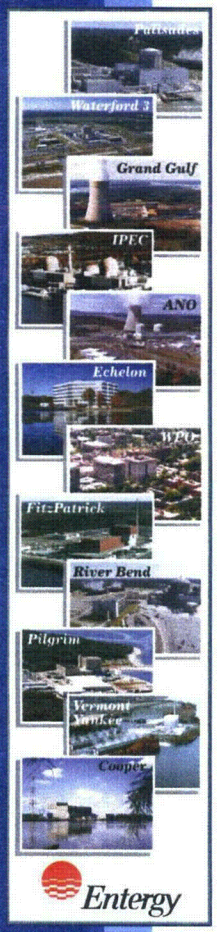
- JAF Program
  - No identified interior/exterior containment surface areas that have substantial corrosion and/or pitting.
  - No identified interior/exterior containment surface areas that are subject to excessive wear from abrasion or erosion that causes a loss of protective coatings, deformation, or material loss.

Torus Monitoring



- JAF Program
  - JAF has identified 29 locations on the interior surface of the torus (suppression pool) that have minor pitting.
  - JAF monitors these locations through the CII Inspection Program which requires more frequent examinations than augmented examinations required by IWE-1241.

Torus Monitoring



BAY H-S8-0.629
PLATE
UT EXAM MIN. READING

1998
BAY B-S8-0.620

2004
BAY B-S3-0.613
S4-0.668
BAY H-S3-0.618
S8-0.629
BAY K-S5-0.658
S5-0.639
BAY O-S5-0.622
S5-0.632
S10-0.604

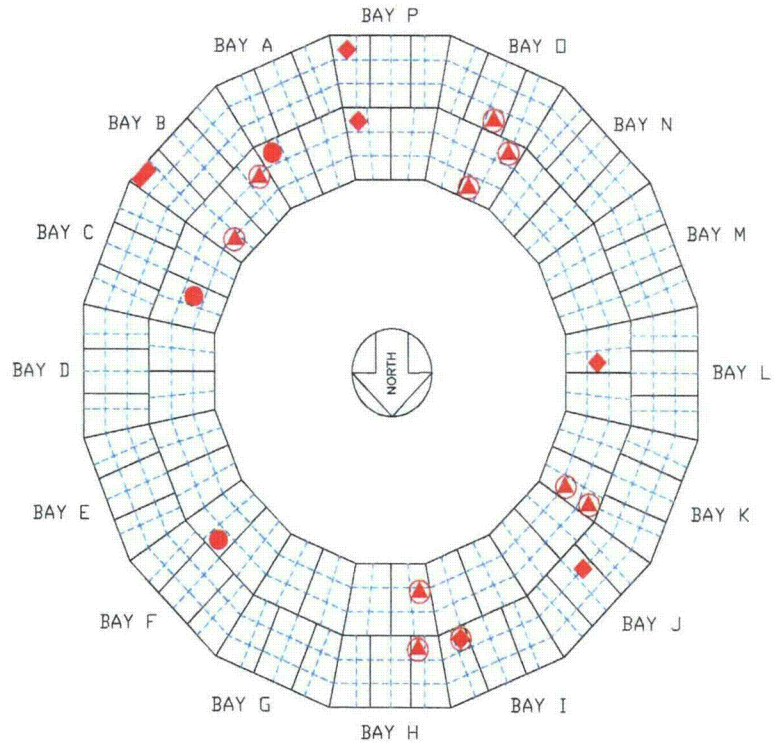
2006
BAY I-S11-0.566
BAY J-S9-0.623
BAY L-S3-0.606
BAY P-S3-0.618
S8-0.661

2008 (SCHEDULED)
BAY A-S4
BAY C-S4
BAY F-S4

2004 REPEAT
BAY B-S3
S4
BAY H-S3
S8
BAY K-S5
S5
BAY O-S5
S5
S10

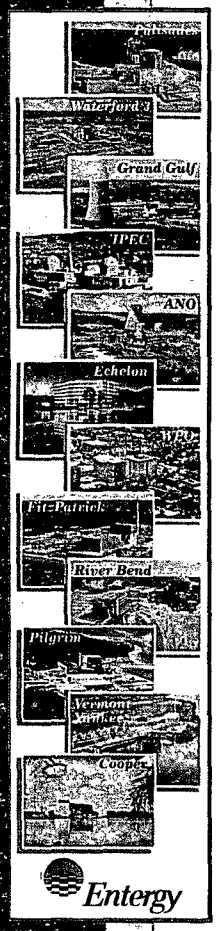
2006 REPEAT
BAY I-S11

2010 (SCHEDULED)
TORUS DESLUDGE
IWE VISUAL INSPECTION (DIVERS)
ADDITIONAL UT INSPECTIONS (TBD)



TORUS SHELL – BELOW CENTERLINE

Torus Monitoring

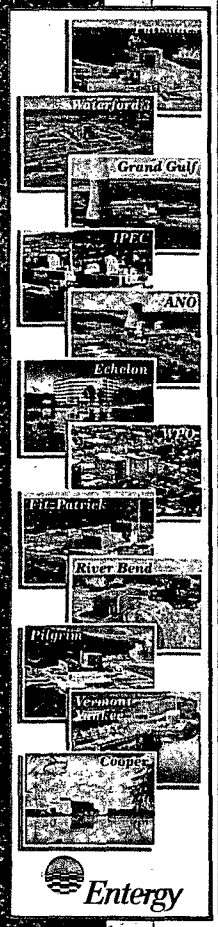


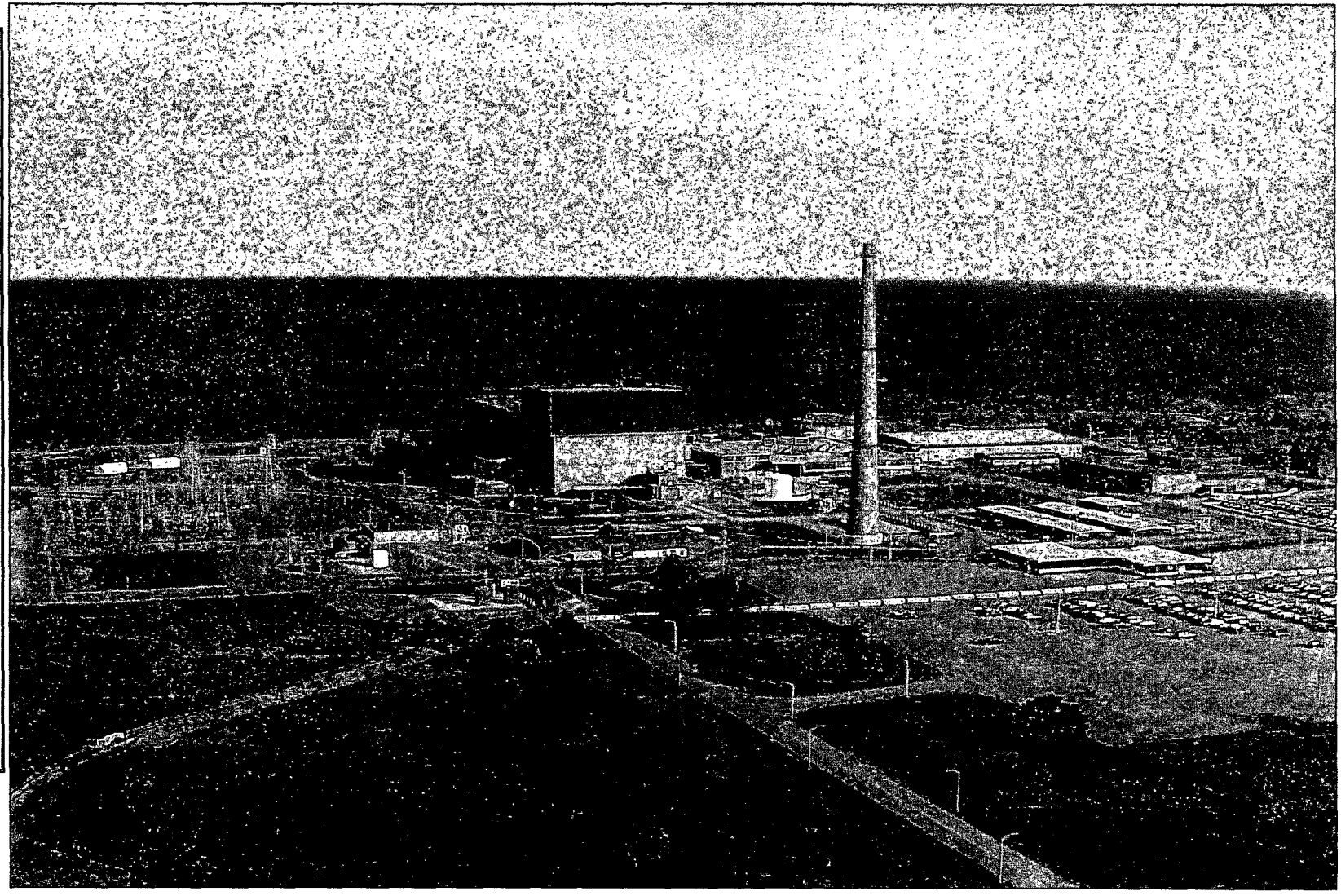
- Ongoing Actions to Ensure Structural Integrity
  - Primary Containment system is inerted with nitrogen and provides atmosphere that is not conducive to corrosion of containment interior surfaces.
  - Torus Preservation and monitoring of interior surfaces identifies and mitigates Torus interior degradation and coating issues.

Torus Monitoring

- Ongoing Actions to Ensure Structural Integrity
  - IWE general examinations monitor the accessible Torus surfaces for degradation.
  - IWE examinations are used to evaluate conditions of the wetted surface areas when drain down or desludging is performed.
  - Torus wall thickness monitoring is performed by ultrasonic examination per the IWE program.

Comments and Questions





U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Full Committee

Vermont Yankee Nuclear Power Station Safety Evaluation Report (Environmental Fatigue)

March 6, 2008

Jonathan Rowley, Project Manager
Office of Nuclear Reactor Regulation

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Agenda

- Recap of Environmental Fatigue discussion from February 7, 2008 ACRS meeting on Vermont Yankee SER
- Resolution of Environmental Fatigue concerns
- New License Condition

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Protecting People and the Environment

Environmental Fatigue recap

- VY revised its application to use its Fatigue Monitoring Program to manage metal fatigue for the extended period of operation
- Corrective Actions element of program allows for reanalysis of components to demonstrate limits will not be exceeded during extended period of operation
- VY submitted results of its reanalysis (incorporating environmentally assisted fatigue (EAF)) on September 17, 2007

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Environmental Fatigue recap

- NRC onsite audit of reanalysis calculations on October 9 and 10, 2007
- Six audit questions added to Question and Answer database
- Request for additional information (RAI) sent on November 27, 2007
- Response to RAI received on December 11, 2007
- Public meeting on January 8, 2008
  - Agreed to submit confirmatory analysis

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Environmental Fatigue recap

- Confirmatory analysis was to include:
  - Performing benchmarking calculations on the VYNPS feedwater nozzle using the axisymmetric finite element model (FEM), taking fully into account all stress components on the nozzle and using the ANSYS FEM computer code to model all defined transients;
  - Demonstrating that the Vermont Yankee specific benchmarking calculations bound the results for the Core Spray and Recirculation outlet nozzles;
  - Calculating fatigue cumulative usage factors (CUFs) using NRC approved ASME Section III NB-3200 methodology;
  - Comparing the resulting CUFs to the previous environmental assisted fatigue calculations to establish whether the previous calculations are adequate.

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Environmental Fatigue Resolution

- VY submitted updated (confirmatory) analysis for the feedwater nozzles on January 30, 2008.
  - Same parameters, data, and methodology used as agreed upon
  - CUFs for safe end and blend radius lower than previous analysis

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Environmental Fatigue Resolution (cont.)

- Supplemental information was submitted on February 5, 2008.
  - Demonstrated that updated (confirmatory) feedwater nozzle analysis bounds geometry of the recirculation outlet nozzle.
  - Described how water chemistry effects are accounted for in the analysis.

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Environmental Fatigue Resolution (cont.)

- NRC audited and reviewed the updated (confirmatory) analysis on February 14, 2008:
  - Axisymmetric finite element model,
  - Analyzed transient definitions and cycles,
  - Water chemistry input
  - Inputs used to develop fatigue life correction factors (F_{en})
    - Dissolved oxygen
    - Strain rate
    - Temperature
    - Sulfur content

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Environmental Fatigue Resolution (cont.)

- Updated (confirmatory) analysis declared "analysis of record" on February 21, 2008.
  - Previous analyses used maximum F_{en} for all transient pairs
  - Updated analysis uses more appropriate F_{en} for each transient pair
  - Green's function application could underestimate CUF
  - Followed ASME Code

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Conclusion

- Updated (confirmatory) analysis is "analysis of record" for EAF CUF values for the feedwater nozzle.
- CUFs calculated in accordance with ASME Code, Section III
- Core spray and reactor recirculation nozzles analysis must be performed.
  - Fourth license condition

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License Condition

- The fourth license condition requires that the licensee perform and submit to the NRC for review and approval, a ASME Code analysis for the reactor recirculation outlet nozzle and the core spray nozzle at least two years prior to the period of extended operation. These analyses should be documented in the FSAR as the "analysis of record" for these two nozzles.

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Questions

Presentation to the ACRS

ESBWR Safety Evaluation Report with Open Items
Chapters 9, 10, 13, and 16

Amy Cubbage, Senior Project Manager, NRO

March 6, 2008

ESBWR Chapters 9, 10, 13 and 16

Presenters

- Lead Project Manager
  - Amy Cubbage
- Reviewers
  - Jorge Hernandez, Balance of Plant Branch
  - David Shum, Balance of Plant Branch
  - Craig Harbuck, Tech Specs Branch
  - Additional reviewers in attendance

ESBWR Chapters 9, 10, 13 and 16

- Discussion topics
  - Chapter 9 - Auxiliary Systems
    - Spent Fuel Pool Passive Decay Heat Removal
    - Inclined Fuel Transfer System
    - Instrument Air and Service Air
    - Hydrogen Water Chemistry
    - Emergency Lighting
  - Chapter 10 - Steam and Power Conversion
    - No specific discussion topics identified
  - Chapter 13 - Conduct of Operations
    - No specific discussion topics identified
  - Chapter 16 - Technical Specification
    - Surveillance Requirements for Passive ECCS and Containment Cooling
    - Surveillance Frequencies
    - Bracketed Items

Chapter 9 – Spent Fuel Pool Passive Decay Heat Removal

- Staff reviewed GEH's boiloff analysis.
  - 3,512 bundles = SFP @ full capacity + 1 full core with closed gates
  - 1,690m^3 (equivalent to 8.85 m) lost in 72hrs
  - ~2.0m remain above TAF @ 72 hours
- Safety-related Alarms
  - Low level – just below normal level (not more than 2.0m below the normal level)
  - Safe shielding – 3.05m above TAF plus margin
  - TAF elevation – alert that fuel has been exposed
- Staff requested GEH to address a postulated drain through the gates, to define distance between TAF and bottom of gates and time to expose starting at the bottom of the gates. This remains an open item.

Chapter 9 – Inclined Fuel Transfer System

- Staff discussed passive cooling analysis with GEH
  - Worst case time-to-boil for two stuck assemblies is **10 hours**
    - Assemblies at the bottom of tube
    - Tube is partially drained
    - Bottom gate valves closed
    - Makeup water can be added via upper manual valves or bottom valves
    - Doses have been analyzed
- Staff finds there is sufficient time and ability to provide makeup

Chapter 9 – Instrument and Service Air

ACRS Concern: Impacts of Moisture and Contamination in Service Air Systems (SAS) on Instrument Air System (IAS) Resulting From the IAS Filter/Dryer Units Being Bypassed on Actions Taken by Operators

These systems are:

- Continuously monitored for air moisture content
- Periodically tested in accordance with ANSI/ISA-7.0.01-1996
- The bypass line is used only in the event that both IAS filter/dryer train fail at the same time

Chapter 9 – Instrument and Service Air

By design, these systems are:

- Non-safety related systems and do not perform safety-related function
- Not considered as a candidate for RTNSS, and not required to achieve or maintain safe shutdown of the plant
- Pneumatically operated devices, designed as fail-safe and not required to have continuous air supply under emergency or abnormal conditions
- Failure of the IAS and SAS does not compromise any safety-related system or component nor does it prevent a safe shutdown

Chapter 9 – Instrument and Service Air

Conclusion:

The staff concludes that impacts of moisture and contamination in SAS on IAS resulting from the IAS filtration/dryer units being bypassed would be minimal.

Chapter 9 – Emergency Lighting

- Staff issued RAI 9.5-60 Supplement 1
- GEH response dated 2/26/08
  - GEH response clarifies that emergency lighting in the remote shutdown area is fed from the safety-related UPS for 72-hours similar to the power supply arrangement for the MCR emergency lighting
  - GEH committed to update in DCD rev 5
- GEH response acceptable however conforming change to ITAACs are needed (RAI 9.5-60, Supplement 2, to be issued)

Chapter 9 - Hydrogen Water Chemistry

- Hydrogen water chemistry (HWC) system – included as an option
  - Current regulations do not require licensees/applicants to implement HWC
- No safety significant issues associated with treating HWC as an option
  - ESBWR Class 1 and 2 materials - resistant to SCC degradation
  - Degradation would be identified through in-service inspection as required by ASME Code
  - HWC is available to the licensee/applicant for managing degradation

Chapter 16 – Technical Specifications

- Passive ECCS and Containment Cooling Surveillance Requirements
  - ADS, GDCS, ICS, PCCS, IC/PCC Pools
  - Inservice Testing
    - Squib valve testing
    - ICS return line valve testing
    - GDCS injection line check valves
  - Non Condensable Gas Venting
- Resolution of Bracketed items

Chapter 16 – Technical Specifications

Frequency	Surveillance	ADS	GDCS	ICS	PCCS	IC/PCC Pools
12h	Pool Inventory		x			
24h	RPV Vent Capacity		x			
24h	Pool Inventory		x			x
24h	Pool Average Temp.					x

Chapter 16 – Technical Specifications

Frequency	Surveillance	ADS	GDCS	ICS	PCCS	IC/PCC Pools
31d	Nitrogen Pressure for Valves	x		x		
31d	Valve Position Verification			x		
31d	Squib Firing Circuit Continuity	x	x			
24m	Automatic Valve Actuation	x	x	x		x

Chapter 16 – Technical Specifications

Frequency	Surveillance	ADS	GDCS	ICS	PCCS	IC/PCC Pools
24m	Verify Valve Locked Open			x		x
24m (72m)	SRV Manual Actuation	x				
24m (144m)	Verify Drain Lines to GDCS Pool, Vent Lines to Suppression Pool and Flow Path through Condenser from Drywell Unobstructed				x	

Chapter 16 – Technical Specifications

Frequency	Surveillance	ADS	GDCS	ICS	PCCS	IC/PCC Pools
24m (96m)	IC Heat Removal Capacity Verification			X		
10y	Verify Flow Paths Unobstructed		X			
10y	Verify Vent Path From Pools Unobstructed					X
92d	Verify Vent & Drain Line Unobstructed Prior to Start Up				X	

Chapter 16 – Technical Specifications

Conclusions

- Frequencies are consistent with STS and are acceptable based on operating experience with similar components and engineering judgment
- Generic TS SRs for passive ECCS and containment cooling will provide adequate assurance of system operability

Chapter 16 – Technical Specifications

Conclusions (cont.)

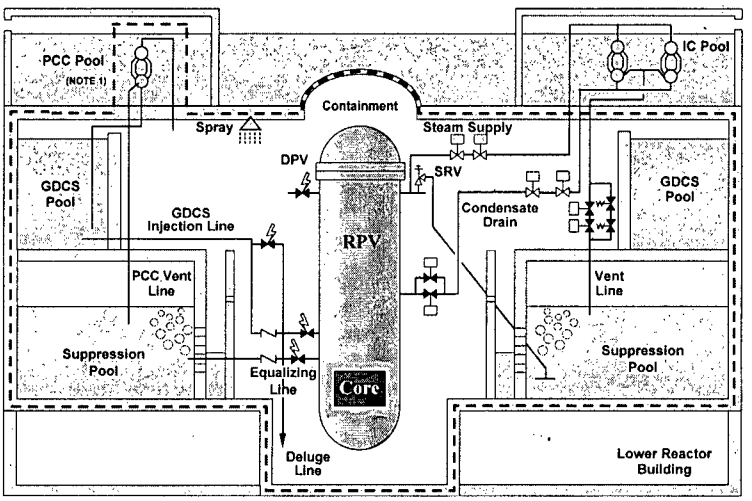
- Pending resolution of Open Items, cannot conclude the ESBWR generic TS comply with 10 CFR 50.34, 10 CFR 50.36 and 10 CFR 50.36a
- Completion of generic TS review contingent upon resolution of design and analysis issues outside of DCD chapter 16

ACRS Presentation
ESBWR Design Certification Review

Discussion/Committee Questions

BACKUP

3/6/2008 19



Schematic of ESBWR ECCS

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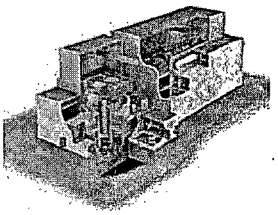
ESBWR DCD Tier 2, Chapters 9, 10, 13, and 16

Advisory Committee on Reactor Safeguards



March 6, 2008

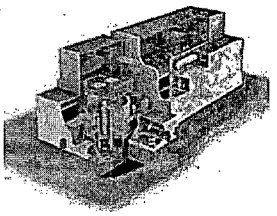
GE Hitachi Nuclear Energy

ESBWR DCD Tier 2

- Chapter 9, Auxiliary System
- Chapter 10, Steam and Power Conversion System
- Chapter 13, Conduct of Operations
- Chapter 16, Technical Specifications

ESBWR - Overview
DCD Chapter 9 Balance of Plant & Auxiliary Systems

Advisory Committee on Reactor Safeguards



Michael A. Arcaro
March 6, 2008

GE Hitachi Nuclear Energy

Overview of Chapter 9 - Auxiliary Systems

- Chapter 9 Provides Description of ESBWR Auxiliary and Balance of Plant Systems Required to Support Operation of ESBWR Under Normal, Transient, Shutdown and Emergency Conditions
- The ESBWR Auxiliary / Support Systems Incorporates Design Features Similar to Those Auxiliary and Support Systems Utilized in Past BWR Designs

Overview of Chapter 9 - Auxiliary Systems

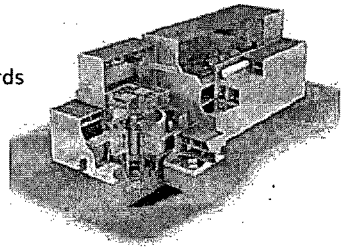
- Section 9.1– Fuel Storage and Handling Systems
  - New Fuel Storage
  - Spent Fuel Storage
  - Fuel and Auxiliary Pools Cooling System
  - Light Load Handling System (Related to Refueling)
  - Overhead Heavy Load Handling Systems
- Section 9.2– Water Systems
  - Plant Service Water, Reactor Components Cooling Water System & Chill Water Systems are RTNSS Systems
- Section 9.3– Compress Gas Systems
  - Instrument Air System (IAS) and Service Air System (SAS)
  - Containment Inerting Systems (CIS) and High Pressure Nitrogen Supply Systems (HPNSS)
  - Hydrogen Water Chemistry System (HWCS)
- Section 9.4 – Heating, Ventilation and Air Conditioning
  - Control Building HVAC, Fuel Building HVAC, Radwaste Building HVAC, Turbine Building HVAC, Reactor Building HVAC, Electric Building HVAC, Drywell Cooling System
- Section 9.5 – Other Auxiliary Systems
  - Fire Protection System and Support Systems for Diesel Generator
  - Lighting System and Communication System

ACRS Topics of Interest

- Hydrogen Water Chemistry (HWC)
  - ESBWR uses similar material and process selections as ABWR with operational history to date showing no evidence of stress corrosion cracking
  - HWC is optional design for ESBWR
- Instrument Air / Service Air Moisture and Contamination
  - IAS design provides redundant air dryer with air quality maintained from SAS compressors (oil free with particles less than 10 microns) by continuously monitoring dew point and periodically testing air quality (ISA 7.0.01) (Ref RAI 9.3-41)
- Control Room Habitability Issues
  - Passive Heat Sink- (Ref RAI 9.4-33)
  - Habitability- long term air quality while maintaining required differential pressure with design airflow rate.
- Isolated Inclined Transfer Tube Containing 2 Fuel Bundles- Evaluate Cooling
  - ESBWR design bounded by BWR/6 analysis

ESBWR DCD Chapter 10 Steam and Power Conversion System

Advisory Committee on Reactor Safeguards



Jack Noonan
March 6, 2008

GE Hitachi Nuclear Energy

Power Cycle Design Overview

- DCD Chapter 10 Content Considers Guidance in NUREG-0800, Standard Review Plan, Sections 10.2 to 10.4.7
- Turbine, Generator, and Power Cycle Systems Do Not Perform or Support Any Nuclear Safety-Related Functions
- The ESBWR BOP Based Upon a Very Conventional BWR Power Plant Cycle ~20% larger than large BWR 6

Turbine and Generator

- Turbine Rotors Utilize Integral Forgings (Monoblocks) to Minimize the Probability of Missile Generation (pre-tested to 120% of rated speed)
- GE has a Long History with this Design Replacing the Old Shrunk on Wheel Style
- A Standard Design Synchronous Generator with Water Cooled Stator Windings and a Hydrogen Cooled Rotor Rated at 1933 MVA (~1600 MWe Gross)

Enhanced Design Features

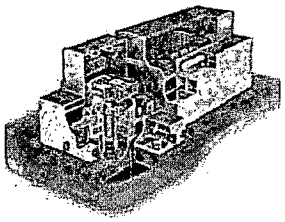
- Turbine Missile Considerations
  - > Integral Forgings (Monoblock)
  - > Favorable Orientation
- Adjustable Speed Motor-Driven Feedwater Pumps
- Elimination of Gland Seal Steam Evaporator
  - > Improved Reliability
  - > Reduce Maintenance Dose
- Fully Electronic, Redundant, Fail-Safe, and Testable Overspeed Protection System

Summary

- The ESBWR BOP Designed with Flexibility and can be Sited Anywhere the Design Parameters are met for the Cooling Water Systems (one basic design)
- The Design Incorporates Best Practices & Incorporates Many Industry Lessons Learned
- Fewer BOP Transients, Longer Plant System Life, and Improved Plant Availability through On-Line Testing and Maintenance

ESBWR DCD Chapter 16 Technical Specifications

Advisory Committee on Reactor Safeguards



Dan Williamson
March 6, 2008

GE Hitachi Nuclear Energy

ESBWR TS Development Philosophy

- BWR/6 Standard Technical Specifications (NUREG-1434, Rev 3.1) Utilized as the Basis for Standard Content / Numbering / Form & Format
  - Standardization With Existing Technical Specifications
  - Completion Times and Surveillance Frequencies
    - Generally Consistent with NUREG-1434
    - Utilized Established Precedent
    - Based on Engineering Judgement
- ESBWR-Specific Safety Analyses and Systems Evaluated to Meet Criteria of 10 CFR 50.36
- TS for New Passive Systems Evaluated Specifically

Passive System Surveillances – Precedents Applied

- Gravity-Driven Cooling System (GDCS)
  - Inspection for Flow Obstruction
  - Frequency - Similar to Containment Spray Headers
  - ASME IST of Check Valves and System Flushing – Each Outage
- Isolation Condensers (ICs)
  - Inservice Heat Transfer Test (Stagger 24 Months x4)
- Squib Valve Applications
  - Standby Liquid Control Precedents
  - Firing Circuit Continuity Verification
  - ASME IST (Batch Sample & Replacement Each Outage)

Published Allegations& Reports: Assessing Nuclear Vulnerabilities and Critical of G4S/Wackenhut nuclear security:

"It's taken a long time, as well as a big rise in the cost and demand for energy, for the nuclear-power industry to shake off past safety scares ... If operators can't figure out how to keep their security guards awake, then we may have to hit the snooze button on the nuclear renaissance."

When Snoozing Becomes Alarming Motley Fool January 11, 2008
http://www.fool.com/investing/high-growth/2008/01/11/when-snoozing-becomes-alarming.aspx?terms=nuclear&vstest=search_042607_linkdefault

INDUSTRY ISSUE: INADEQUATE NUCLEAR SECURITY STANDARDS

"While the United States has one of the world's most well-developed regulatory systems for protecting nuclear facilities against sabotage and attack, today's security standards are inadequate to defend against credible threats.

Findings:

Sabotage of a nuclear reactor could result in a large release of radiation.

If a team of well-trained terrorists forcibly entered a nuclear power plant, it could disable safety systems within a matter of minutes, and do enough damage to cause a meltdown of the core, failure of the containment structure, and a large release of radiation. Such an attack could contaminate large regions for thousands of years, producing higher cancer rates and billions of dollars in associated costs."

There is no assurance that reactors can be defended against terrorist attacks.

The NRC stages mock attacks to determine if plant owners can defend their reactors against DBT-level attacks. Test results reveal poor performance, and the integrity of the tests themselves is in question. The federal government is responsible for defending against attacks more severe than the DBT, but it has no mechanism for ensuring that it can provide such protection."

Nuclear power in a warming world: Assessing the Risks, Addressing the Challenges
Union of Concerned Scientists December 2007

CONGRESSIONAL INVESTIGATION

"Rep. John D. Dingell (D-MI), Chairman of the Committee on Energy and Commerce, and Rep. Bart Stupak (D-MI), Chairman of the Subcommittee on Oversight and Investigations, today announced they will conduct a comprehensive review of the Nuclear Regulatory Commission's (NRC) operations following reports of security guards sleeping on the job at the Exelon Peach Bottom nuclear power plant in York County, Pennsylvania.

'The NRC's stunning failure to act on credible allegations of sleeping security guards, coupled with its unwilling-ness to protect the whistleblower who uncovered the problem, raises troubling questions,' said Rep. John D. Dingell, Chairman of the Committee on Energy and Commerce. 'It appears that there has been a systematic failure, by both NRC officials and the nuclear plant licensee, to ensure that these high-risk facilities are secure and employees are not discouraged from expressing concerns about safety.'

'The Committee would like to know whether it was the repeated notification from a concerned employee or the threat of a videotape showing security workers asleep on the job appearing on the evening news that prompted the licen-see to look into this matter," said Rep. Bart Stupak (D-MI), Chairman of the Subcommittee on Oversight and Investiga-tions. "In addition, the Committee wants to know why the NRC

remains confident in this same contractor's ability to secure other nuclear facilities throughout the country.'"

Energy and Commerce Committee to Probe Breakdowns in NRC Oversight US Fed News January 7, 2008

INCREASING CALLS TO INTEGRATE SECURITY INTO THE RELICENSING PROCESS

"The tragedy that befell our nation on September 11, 2001 demonstrated the utter folly of ignoring the impact of national security issues on nuclear plant safety. The release of radioactive material into the air and water after the recent earthquake in Japan – forcing the emergency shutdown of the world's largest nuclear plant – demonstrates the vulnerability of nuclear plants to natural forces. These facts and the latest National Intelligence Estimate's finding that terrorist capability has recovered underscore the importance of our request that NRC expand its criteria for relicensing to examine all matters involving nuclear plant safety and risk.

The NRC's failure to amend its relicensing regulations is inconsistent with the NRC's own motto of 'Protecting People and the Environment .' By forgoing a vital opportunity to evaluate the entirety of threat to public health and safety in a single, unified public relicensing proceeding, NRC remains blind to its mandate from Congress to protect the public from the dangers inherent in nuclear power generation . We encourage the NRC to change course."

State Attorney Generals' Letter to NRC Chairman Dale E. Klein, Chief Legal Officers of: Connecticut, Delaware, Illinois, Kentucky, New York, and Vermont, November 15, 2007

"Attorney General Andrew M. Cuomo today announced that he and the Attorneys General of five other states have submitted a letter to the Nuclear Regulatory Commission (NRC) expressing serious concerns about the NRC's continued disregard of safety issues - including susceptibility to earthquakes or terrorist attacks - when deciding whether to renew the operating license of a nuclear power plant beyond its initial 40 year term."

Attorney General Cuomo & 5 Other States Demand NRC Consider Terrorism and Earthquakes When Relicensing Nuclear Plants Office of the New York State Attorney General Andrew M. Cuomo November 15, 2007

"The Environmental Protection Agency, in a break from the federal nuclear authority, says the potential impact of terrorism should be considered in deciding whether to relicense the Indian Point nuclear power plants."

EPA: Nuclear licenses should weigh terrorism Associated Press October 30, 2007

"Attorney General Stuart Rabner announced today that New Jersey has filed a petition with the federal Third Circuit Court of Appeals challenging a finding by the Nuclear Regulatory Commission (NRC) that it need not consider the impact of a terrorist attack as part of its relicensing review of the Oyster Creek nuclear power plant in Lacey Township, Ocean County.

...

It is difficult to reconcile the NRC's actions with its stated position on the Oyster Creek matter," said Rabner. "On the one hand, the NRC has imposed extensive security requirements on nuclear power plants since 9/11 to guard against attacks. On the other hand, it continues to insist that, from a legal perspective, the likelihood of such an attack is merely theoretical, and not worthy of analysis as part of the relicensing process."

AG Rabner Announces 3rd Circuit Court Challenge to NRC Ruling on Oyster Creek; N.J. Contends Impact of Terrorist Strike Should be Considered In Relicensing Review
Office of the Attorney General of New Jersey, Stuart Rabner April 25, 2007

"'This is a public safety concern for all Illinoisans, as well as for those throughout North America,' Attorney General Madigan said. 'With a total of six nuclear generating plants and 11 reactors, Illinois has more nuclear generating facilities than any other state in the country. Our national security concerns have changed since these power plants first were built...We rely on the NRC to ensure the operating licenses for these plants are not renewed until we are completely confident that the plants can avoid a catastrophe.'"

Madigan Calls for Stricter Regulations When Relicensing Nuclear Power Plants

Office of the Attorney General of Illinois, Lisa Madigan November 15, 2007

G4S/WACKENHUT: NEI FORCE ON FORCE CONTRACT & POTENTIAL CONFLICT OF INTEREST

"Since drawings of U.S. nuclear power plants were found in al-Qaida caves in Afghanistan, the nuclear power industry says it has spent $1 billion beefing up security. That includes more frequent and more realistic mock-terrorist attacks to test the ability of plant guards.
That's an improvement, critics say, but for one key fact: the company hired to run the security tests — Wackenhut Corporation — also is providing security at half the plants. Critics charge Wackenhut has a vested financial interest in making plant security look good."

Conflict of interest may hurt nuke security NBC Nightly News with Tom Brokaw September 8, 2004

"Wackenhut is responsible for nuclear reactor security at 30 of 64 nuclear power plants in the U.S. Don't you think that there would be a disincentive for the Wackenhut mock terrorist force to rigorously test security at power plants at which Wackenhut also provided the security guard forces as rigorously as it would at power plants at which Wackenhut's competitors provided the security guard forces? If not, why not?"

Letter to NRC Chairman Nils J. Diaz Congressman Edward J. Markey August 23, 2004

"...We were shocked to learn that Nuclear Energy Institute (NEI), the lobbying arm of the nuclear industry, has hired the Wackenhut Corporation to supply and manage these adversary teams. This is more than a case of the proverbial fox guarding the henhouse. It is not an apparent conflict of interest—but a blatant conflict of interest."

Letter to U.S. NRC Chairman Nils J. Diaz Project on Government Oversight (POGO) July 30, 2004

G4S/WACKENHUT: FORCE-ON-FORCE PROBLEMS

"In August 2004, a force-on-force exercise was held at the NTS [Nevada Test Site]. It is my understanding that during this exercise, two Wackenhut guards confronted each other after rounding a corner of a building, one 'shot' the other in a friendly fire incident, and the second then started a fist fight with the first because he was angry about being 'killed.' Needless to say, the guard force failed the force-on-force exercise."

Letter to Secretary of the Energy Samuel Bodman Congressman Edward J. Markey February 17, 2005

"Whistleblowers at the South Texas Project nuclear power plant have reported instances of security guards failing to follow protocol, leaving the facility vulnerable to intruders, according to a study by the Union of Concerned Scientists...The report further states that guards' radio equipment doesn't work properly, some mock intrusion drills don't reflect real-world situations, and cleaning and maintenance staff has access to a room where weapons are stored."

Nuclear plant's security faulted Dallas Morning-News September 6, 2006

"[Energy Department Inspector General] Friedman's office also found that one Wackenhut unit, hired by the NRC to simulate an attack on nuclear facilities, had tipped off another Wackenhut unit charged with guarding the facilities at Y-12 about the attack strategy. Danielle Brian, executive director of the Project on Government Oversight, said in a 2004 letter to the NRC that 'this is more than a case of the proverbial fox guarding the henhouse. It is not an apparent conflict of interest -- but a blatant conflict of interest.'"

Video of Sleeping Guards Shakes Nuclear Industry Washington Post January 4, 2008

No Assurance of Adequate Defenses against Attack
"The NRC periodically stages mock DBT-level attacks to determine if plant owners can defend against them (this is called force-on-force testing). At nearly half the nuclear plants tested before 9/11, three mock attackers were able to enter quickly and simulate the destruction of enough safety equipment to cause a meltdown—even though operators typically received six months' advance notice of which day the test would occur. The integrity of the tests themselves is also open to question. The NRC awarded Wackenhut the contract to supply the mock adversary team for all force-on-force tests, even though that company supplies the security officers for nearly half of all U.S. nuclear power plants. This situation represents a serious conflict of interest. In fact, the GAO found that one plant's security team performed better during a mock attack because it had obtained advance information about the planned attack scenario."

Nuclear power in a warming world: Assessing the Risks, Addressing the Challenges
Union of Concerned Scientists December 2007

G4S/WACKENHUT: ALLEGED CHEATING AND OTHER SHORTCOMINGS ON SECURITY DRILLS

"[Energy Department Inspector General] Friedman's office also found that one Wackenhut unit, hired by the NRC to simulate an attack on nuclear facilities, had tipped off another Wackenhut unit charged with guarding the facilities at Y-12 about the attack strategy. Danielle Brian, executive director of the Project on Government Oversight, said in a 2004 letter to the NRC that 'this is more than a case of the proverbial fox guarding the henhouse. It is not an apparent conflict of interest -- but a blatant conflict of interest.'"

"Last summer, in testimony before a subcommittee of the House Oversight and Government Reform Committee, Friedman said, 'We did not use the word 'cheating' in the report, but it was. The test was compromised.'"

Video of Sleeping Guards Shakes Nuclear Industry Washington Post January 4, 2008

G4S/WACKENHUT: REPORTED WEAPONS VIOLATIONS

"Federal regulators said they are proposing a $208,000 fine against Florida Power & Light Co. for security violations at the Turkey Point nuclear power plant. ... In April 2004, FP&L failed to ensure that two armed guards had operable weapons, the agency said. Specifically, it said a contract security officer, employed by Wackenhut Corp., had intentionally removed the firing pins from two weapons. In August 2005, FP&L again failed to ensure that armed responders were equipped with functional weapons, the NRC said. Specifically, a Wackenhut contract security lieutenant removed and broke a firing pin from a weapon." An FPL spokesperson said that the individuals involved in the incident no longer work there.

*FP&L Faces Fine over Security Violation*South Florida Business Journal January 22, 2008

"In 2003, a Wackenhut employee took two government-owned handguns and one of his own in a briefcase to the National Nuclear Security Administration's Nevada test site, according to an IG report."

Video of Sleeping Guards Shakes Nuclear Industry Washington Post January 4, 2008

"CBS4 discovered the apparent security shortfall during a routine visit to the Turkey Point nuclear power plant Wednesday. When the CBS4 crew arrived at the Homestead facility, they were greeted by a single Wackenhut guard at the front gate. That guard was carrying an M-16 rifle, but upon closer examination, it was clear there was no clip in the gun. The security guard was carrying a very visible, very unloaded gun."

Governor Bush Concerned Over Turkey Point Security CBS4 May 22, 2006

"A former Wackenhut security guard was arrested in Michigan on Friday and charged with stealing a semiautomatic rifle and a thermal rifle sight from St. Lucie Nuclear Plant, authorities said."

Rifle Stolen From St. Lucie Nuclear Plant Recovered, Arrest Made Associated Press March 4, 2006

G4S/WACKENHUT: REPORTED WHISTLEBLOWER RETALIATION

"Exelon Nuclear terminates its contract with Wackenhut Security at its Peach Bottom plant in Pennsylvania after receiving a videotape showing a number of Wackenhut employees sleeping on the job. Exelon thanks the whistle-blower who shot the tape, then lets him go because he works for Wackenhut. " # 68 of

101 Dumbest Moments in Business Fortune December 11, 2007

"Jasinski, a 13-year Wackenhut employee, filed his original complaint with the Occupational Safety and Health Administration, or OSHA, in May 2005, alleging that Wackenhut and Exelon had engaged in discriminatory employment actions, culminating in his suspension and dismissal in April 2005 for engaging in protected activities. These activities included "raising compliance issues with management of both [Exelon and Wackenhut] as part of his duties [and] collecting evidence of violations and calling appropriate enforcement authorities to report violations," Jasinski said in his complaint." The parties reached a settlement, but wouldn't disclose its terms because of a confidentiality agreement.

Exelon, Wackenhut Settle Case Over Nuclear Security Allegations Nucleonics Week July 26, 2006

"The basic facts are that a security guard, employed in a temporary status by The Wackenhut Corporation, brought to the attention of managers the fact that a guard trainee did not have a high school diploma as required for the job. Wackenhut terminated the trainee, as required, but then also terminated the security guard who identified the concern and reprimanded a security training instructor who brought the concern forward, for reasons that the NRC found to be discriminatory. The NRC found that this action violated regulations prohibiting retaliation against workers who bring safety issues to management."

NRC Fines Callaway $55,000 for Retaliation Against Security Personnel
US Nuclear Regulatory Commission May 15, 2001

G4S/WACKENHUT: EXCESSIVE OVERTIME

"In 2005, the inspector general said that at the NNSA's Oak Ridge site, Wackenhut had routinely worked security personnel more than the 60-hour-a-week maximum permitted there. In addition, Wackenhut had misled the government about worker training. It reported planned training as actual training time, and protective-force personnel had signed attendance rosters for on-the-job refresher training they had not attended, the IG report said."

Video of Sleeping Guards Shakes Nuclear Industry Washington Post January 4, 2008

* In 2002, a Wackenhut employee at the Indian Point Nuclear Station in New York told the NRC he was fired after raising a concern about working excessive overtime.
* In 2004, Florida Power and Light sought the NRC's permission to exceed work-hour limits because of a high turnover rate among security workers at its Turkey Point Nuclear Station.
* In 2006, Time magazine reported that excessive overtime at the Pilgrim Nuclear Station in Massachusetts was linked to poor preparedness and performance by the guard force.

Overtime bears risk, guards at TMI fear // Some are putting in 60- to 72-hour weeks Patriot News February 5, 2007

"Guards at TMI work 12-hour shifts, usually for two to three consecutive days, but sometimes longer. Documents provided to The Patriot-News show one officer worked more than 150 hours in a 14-day period, nearly the equivalent of two full-time jobs. The same officer averaged more than 54 hours a week for the first 10 months of 2005."

Hours and fatigue dog TMI guards-Officers told new hires where to 'nap,' memo says Patriot News January 29, 2006

G4S/WACKENHUT: ASLEEP ON THE JOB AT NUCLEAR POWER AND NUCLEAR WEAPONS PLANTS

"Seven guards have been caught sleeping at the Y-12 nuclear weapons plant in Oak Ridge since 2000. . . Y-12, a potential terrorist target containing the key ingredients for a "dirty bomb," makes uranium parts for every warhead in the U.S. nuclear arsenal. It also dismantles old weapons and is the nation's primary storehouse for bomb-grade uranium. . . . Wackenhut Services' napping-guard record in Oak Ridge came up for questioning after its parent company, The Wackenhut Corp., recently lost a security contract for 10 nuclear power plants after sleeping guards were found at a Pennsylvania station."

Feds: 7 Guards Caught Sleeping at Tenn. Nuclear Weapons Plant Fox News (AP) January 16, 2008

"The Nuclear Regulatory Commission, in letters sent to FPL and Wackenhut Nuclear Services, said its investigators had 'substantiated that security officers were willfully inattentive to duty or served as look-outs such that other security officers could be inattentive while on duty.'"

Turkey Point guards snoozed, NRC says Miami Herald October 30, 2007

"They're on duty and fast asleep, security guards that are supposed to be protecting a major terrorist target [Peach Bottom Atomic Energy Station] in the United States. . . . The security officers shown on the video are all employees of Wackenhut, a security firm that is contracted out to manage the guards. Wackenhut also provides security for major federal agencies including NASA and the Army."

Nuclear Plant Guards Asleep On The Job WCBS-TV September 25, 2007

"The disciplining of a security guard at the area's [Limerick] nuclear power plant last week was not the first time the company that provides security there has dealt with a sleeping guard problem . . . As such, Wackenhut's Nuclear Services Division provides security at Three Mile Island, which earlier this year was at the center of a series of news reports regarding sleeping guards."

Security firm has had problems with sleeping guards Pottstown Mercury August 3, 2006

"Veteran guards responsible for training new hires to the [Wackenhut] security force that protects Three Mile Island were sharing a key piece of insider information -- the best places to take a nap, according to an internal memo. . . . The link between hours worked and fatigue is a growing concern among security officers and watchdog groups. . . . 'Excessive work schedules can challenge the ability of security force personnel to remain vigilant and effectively perform their duties,' the agency said in an order."

Hours and fatigue dog TMI guards-Officers told new hires where to 'nap,' memo says Patriot News January 29, 2006

"On April 15, 2003 at about 4:50 a.m., the Oyster Creek Operations Director arrived at the Oyster Creek Nuclear Generating Station (OCNGS) in his vehicle and . . . noticed that the gate barrier was raised in the open position (which he noted was unusual), and that the [Wackenhut] security officers did not immediately exit the guard house to verify his badge. The Operations Director sounded his horn three times, but was unable to get the attention of the security officers. Subsequently, he exited his vehicle, went to the guard house and observed through the window that the security officers appeared to be asleep. He observed that upon knocking at the door the officers became attentive."

Oyster Creek Generating Station – NRC Integrated Inspection Report July 29, 2003

G4S/WACKENHUT: INCREASING CALLS FOR PUBLIC ACCOUNTABILITY

"Miami-Dade and federal investigators raided the headquarters Friday night [Dec. 7] of one of the county's largest government contractors."

Investigators Raid Wackenhut's Headquarters NBC 6 South Florida December 9, 2007

"Over the past year, Sanders has been engulfed by allegations of lapses in security at nuclear plants, an audit over whether it overcharged the city of Miami for transit guards, and a bitter dispute with the Service Employees International Union."

Executive Resigns in Storm Over Sleeping Guards Washington Post January 10, 2008

"The National Nuclear Security Administration is studying the possibility of federalizing guards at nuclear weapons facilities, including Y-12 in Oak Ridge."

Guards at Y-12 might become federalized Knoxville News-Sentinel December 15, 2007

"There's a shakeup at the nationwide security company under fire in Nashville for a costly computer theft. According to Channel 4's NBC sister station in Miami, Wackenhut Security CEO Gary Sanders is stepping down. The move comes the same day Metro Nashville's government acknowledged that Channel 4's analysis of problem billing was correct."

CEO Of Metro Security Contractor Steps Down MSNBC January 9, 2008

Reflecting on Group 4 Securicor's explanation of Gary Sanders resignation as president from Wackenhut, a Washington Post blog noted, "Truthfulness is one of those core values that companies either incorporate into their cultures or they don't.. . .. A company in which people withhold unpleasant information from colleagues and superiors, lie to customers and mislead regulators cannot generally be relied on to level with its investors or the public."

The Reckoning: Corporate Candor Washington Post January 13, 2007

G4S/WACKENHUT: CONGRESSIONAL OVERSIGHT ACTIONS

Testimony of former Wackenhut guard Robin Wright at Oversight Subcommittee on Government Management, Organization and Procurement hearing:
"Unfortunately, I felt that Wackenhut took their government contract and responsibility for our nation's safety too lightly and they provided a shoddy and low level of service to the DHS, which could have had dire consequences for our nation's capital. The problems I witnessed included poor access control, lack of training, careless weapons handling, open posts, failed security tests, security breaches, falsified documents, and irresponsible handling of a hazardous substance attack."

"Federal Contracting: Do Poor Performers Keep Winning?"
Hearing: Oversight Subcommittee on Government Management, Organization and Procurement July 18, 2007

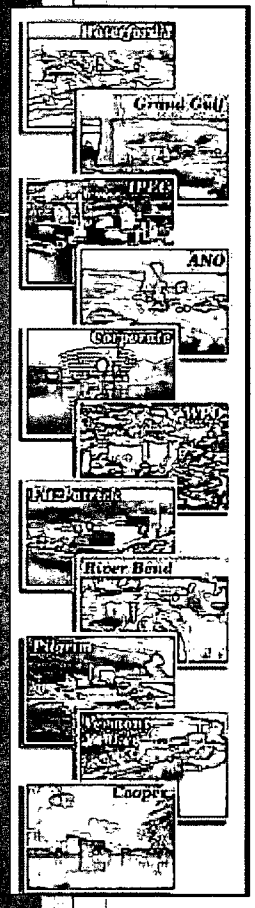
"[U.S. Rep. Robert Brady, D-Pa.] said he would ask Congress to investigate whether Wackenhut should be barred from receiving government contracts."

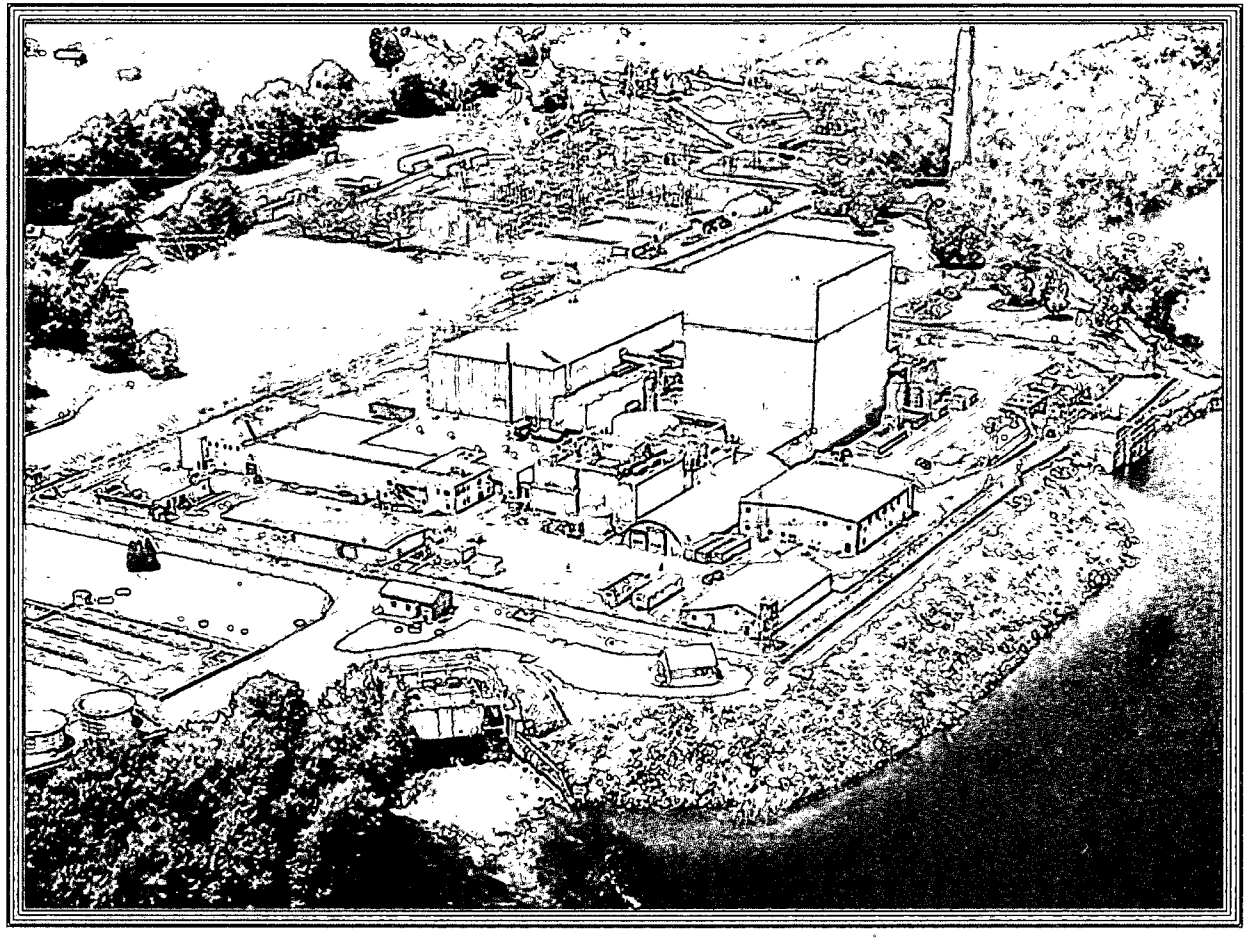
Guards Vote to Join Union Philadelphia Daily News September 13, 2007

Vermont Yankee Nuclear Power Station

ACRS License Renewal Full Committee Presentation on Environmentally Assisted Fatigue

March 06, 2008





Entergy

Entergy Personnel in Attendance

Executives

Ted Sullivan	Vermont Yankee Site Vice President

Corporate Management

Garry Young	Manager, License Renewal

Presentation Panel

John Dreyfuss	Director of Nuclear Safety Assurance
Norm Rademacher	Director of Engineering
Jim Fitzpatrick	Design Engineering - Structural
Gary Stevens	Structural Integrity - Consultant
Scott Goodwin	Design Engineering - Structural
Alan Cox	Technical Manager

Support Management

Dave Mannai	Licensing Manager
Mike Metell	Project Manager

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Agenda

Environmentally Assisted Fatigue (EAF)

- EAF Overview
- EAF Timeline
- Basis for Evaluation
- EAF Evaluation
- Reanalysis of FW, CS, and RR Outlet Nozzles
- Conservatisms in Nozzle Re-analyses
- Chemistry Effects on EAF
- EAF Summary
- NRC Audit of EAF Calculations
- Confirmatory Calculation
- License Condition

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EAF Overview

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EAF Overview

- Scope included the fatigue-sensitive component locations identified in NUREG/CR-6260
  - RPV Shell and Lower Head
  - Feedwater Nozzle (FW)
  - Reactor Recirculation (RR) piping (including RR inlet and RR outlet nozzles)
  - Core Spray (CS) Nozzle and associated piping
  - Residual Heat Removal (RHR) return piping
  - FW piping

- Piping originally designed and analyzed to USAS B31.1-1967; therefore, no original ASME Class 1 piping Cumulative Usage Factor (CUF) calculations

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EAF Timeline

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EAF Timeline

- Completed VY Plant Specific EAF calculations (September 2007)
- Staff audited calculations and raised questions at blend radius for three nozzles (October 2007 – January 2008)
- Public meeting held on EAF calculations (January 8, 2008)
- Completed confirmatory analysis and addressed reactor water chemistry effects (January 30, 2008)
- Completed audit of confirmatory analysis for limiting FW Nozzle (February 14, 2008)
- Submitted LRA Amendment 36 providing chemistry data and supplemental information (February 21, 2008)

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Basis for Evaluation

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Basis for Evaluation

- Consistent with GALL Report
- Evaluated locations specified in NUREG/CR-6260
- Utilized EAF relationships (F_{en} methodology)
  - NUREG/CR-6583 for carbon and low alloy steels
  - NUREG/CR-5704 for stainless steels

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Basis for Evaluation

- Fabrication / As-Built drawings used
- Design vs. Actual Transient Severity used
- Projected cycles to 60 years
- EPU conditions applied for entire 60-year period

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EAF Evaluation

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EAF Evaluation

Site specific analyses for NUREG/CR-6260 locations at VY

- Used existing design analyses for RPV Shell, Lower Head & Recirculation Inlet Nozzles and applied F_{en} (all evaluated using NB-3200 rules)
- Reanalyzed the FW, RR Outlet, & CS Nozzles per ASME NB-3200
- New ASME Class 1 fatigue calculations for RR, RHR and FW piping per ASME NB-3600

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Reanalysis of FW, CS, and RR Outlet Nozzles

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Reanalysis of FW, CS, and RR Outlet Nozzles

- 60 year projected cycles and design transient severity based on VY Design Specification and updated BWR-4 thermal cycle definitions
- Finite element models (FEMs) developed from as-built drawings and material specifications
- Heat transfer coefficients and FEM boundary conditions based on the RPV Certified Design Specification and RPV Stress Report
- Thermal stress response (i.e., Green's Function) developed for a step change in temperature

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Reanalysis of FW, CS, and RR Outlet Nozzles

- Thermal transient component stresses calculated using Green's Function integration for each thermal transient
- Pressure stress intensities directly from FEM for unit pressure load case scaled to account for nozzle corner effects and transient pressure time history
- Stress intensities due to attached piping loads conservatively calculated and scaled based on RPV temperature for each transient

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Reanalysis of FW, CS, and RR Outlet Nozzles

- Maximum stress differences from temperature transients and stress intensities from pressure and attached piping loads were combined per transient definitions

- ASME NB-3200 fatigue calculation performed for the collected thermal transients stress histories

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Reanalysis of FW, CS, and RR Outlet Nozzles

- Bounding fatigue life correction factors (F_{en} multipliers) calculated for water chemistry conditions expected to occur over 60 year operating period

- Environmental fatigue effects calculated by multiplying the CUF for 60 years by the F_{en}

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Conservatisms in Nozzle Re-analyses

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Conservatisms in Nozzle Re-Analyses

- Number of projected transient cycles for 60 years greater than expected cycles based on experience to date
- Used design basis transient severity definitions
- Assumed bounding values for pressure and temperature (at power up-rate conditions) for the entire 60 year period of plant operation
- Calculated bounding F_{en} multipliers using values for temperature, strain rate and sulfur content to maximize the F_{en} multiplier
- Applied bounding F_{en} multiplier to all transient stress pairs

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Chemistry Effects on EAF

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Chemistry Effects on EAF

- Used F_{en} factors specified per NUREG/CR-6583 and NUREG/CR-5704

- Selected inputs to maximize contribution
  - Sulfur content maximum of 0.015 used
  - Strain rate less than 0.001%/sec for all transients
  - Temperature – 550°F used for all locations
  - Dissolved oxygen (DO) based on Plant measured data including excursions
  - DO inputs represent mean plus 1 standard deviation of measured data

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EAF Summary

- EAF CUFs for Vermont Yankee remain below the allowable value of 1.0 for 60 years of operation

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NRC Audit of EAF Calculations

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NRC Audit of EAF Calculations

- NRC questioned VY nozzle reanalysis at FW, CS, and RR Outlet nozzle corners (blend radius)
  - Use of component (i.e., radial, tangential, hoop) stress difference vs. maximum stress intensity (neglects shear stresses)
  - LRA Amendment 33 (RAI 4.3.3-2) documents evaluation using maximum stress intensity vs. component stress difference
  - Results in maximum 0.003 increase in EAF CUF for FW, CS and RR Outlet nozzles

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Confirmatory Calculation

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Confirmatory Calculation

- Feedwater Nozzle analyzed
  - Controlling nozzle with most severe design transients and highest fatigue usage
    - Where cold return enters hot vessel
    - 2-3 times number of design transients vs. other nozzles
    - Industry experience
  - Same FEM model, transients, cycles and water chemistry as used in previous nozzle reanalysis
  - All 6 stress components combined per NB-3216.2 (i.e., shear stresses were included)

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Confirmatory Calculation

- ASME fatigue analysis per NB-3222.4(e) (same as reanalysis)
- Confirmatory calculation used maximum F_{en} factor for each transient pair
- Results reconfirm EAF CUF <1.00 for 60 years

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Comparison of Reanalysis with Confirmatory Calculation

Reanalysis

60 yr Cycles & Design Transients → ANSYS FEM for Pressure Stresses & Conservative Piping Stresses → Thermal Transient Stresses calculated using **Green's functions** → **Combine Maximum Stress Intensities (P+TH+Piping)** → Determine stress range pairs and perform ASME III NB 3224 Fatigue Calculation → Bounding Fen Factors applied to **ALL** Transient Pairs

Confirmatory Calculation

60 yr Cycles & Design Transients → ANSYS FEM for Pressure Stresses & Conservative Piping Stresses → Thermal Transient Stresses calculated using **ANSYS FEM** → **Combine stress components per ASME III NB 3216.2, then calculate Stress Intensities (P+TH+Piping)** → Determine stress range pairs and perform ASME III NB 3224 Fatigue Calculation → Bounding Fen Factor for **EACH** Transient Pair

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Calculation Results

- EAF Analysis results <1.00 (with margin)
- Confirmatory Calculation supports EAF Reanalysis results

Location	Analysis	**EAF CUF / Allowable**
Safe End	Reanalysis	**0.26 / 1.00**
	Confirmatory Calculation	**0.10 / 1.00**
Nozzle Corner (Blend Radius)	Reanalysis	**0.64 / 1.00**
	Confirmatory Calculation	**0.35 / 1.00**

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License Condition

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License Condition

- FW nozzle confirmatory calculation complete
- Reanalysis for CS and RR Outlet show:
  - CS EAF CUF = 0.17
  - RR Outlet EAF CUF = 0.08
- License condition: Perform ASME analysis for CS and RR Outlet Nozzles no later than two years prior to entering the period of extended operation

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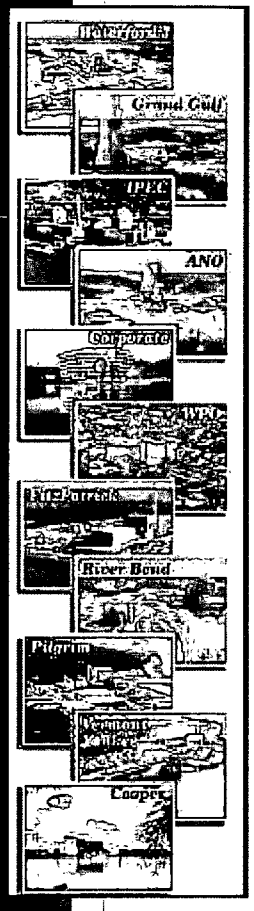
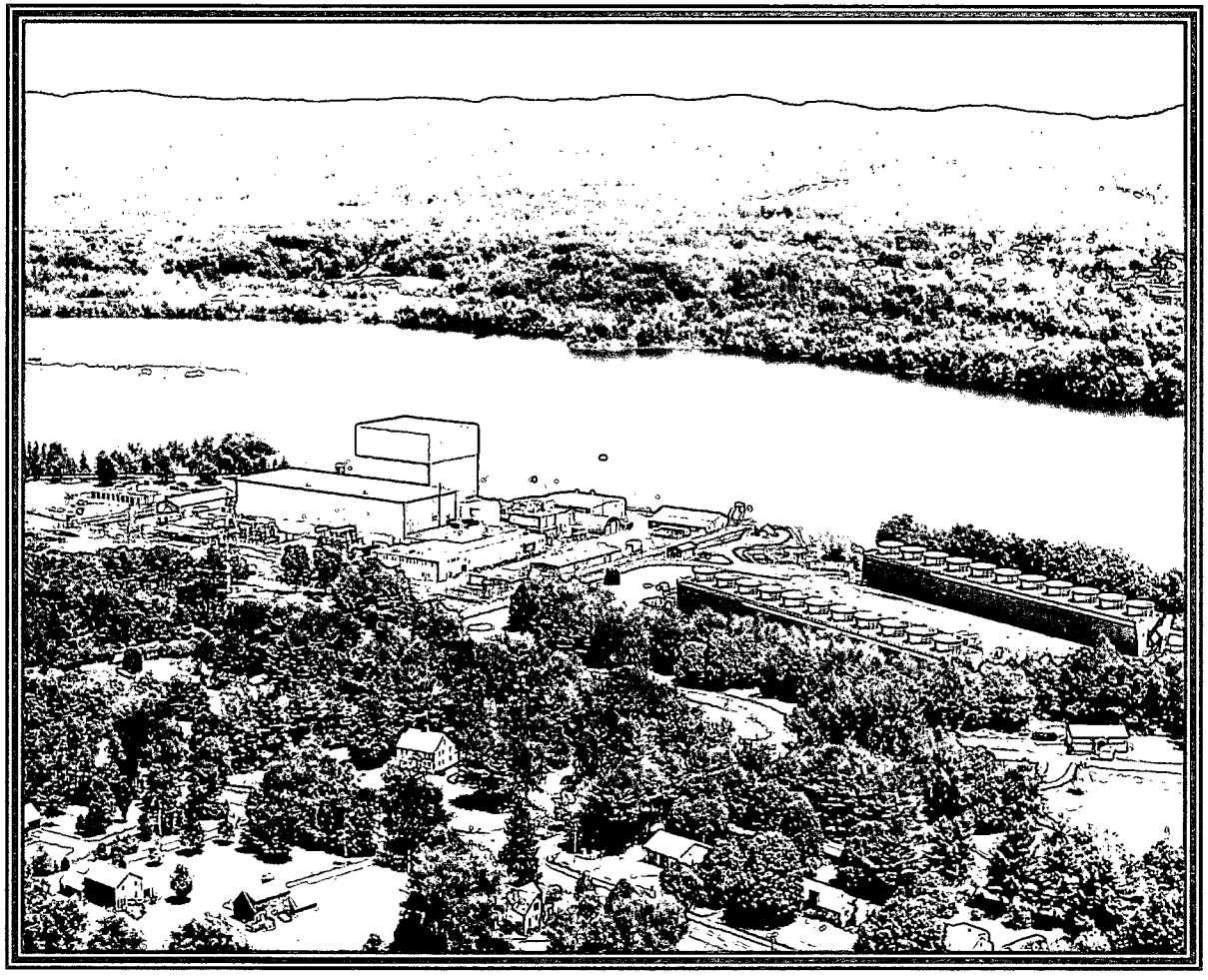
Comments and Questions





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Advisory Committee on Reactor Safeguards (ACRS) License Renewal Full Committee

James A. Fitzpatrick Nuclear Power Plant License Renewal Safety Evaluation Report

Tommy Le, Sr. Project Manager, NRR

Roy Mathew, Audit Team Leader, NRR

Glenn Meyer, Inspection Team Leader, RI

March 6, 2008

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Introduction

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

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Overview

Recap of September 2007 sub-committee meeting

- 346 Audit Questions
- 118 RAIs Issued
- Safety Evaluation Report (SER) With Open Items was issued July 31, 2007
  - Two (2) Open Items
  - Zero (0) Confirmatory Items
  - Three (3) Standard License Conditions

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License Renewal Inspections

Glenn Meyer

Inspection Team Leader, Region I

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Regional Inspection

- 54.4(a)(2) - non-safety SSCs whose failure could affect safety SSCs
- Spatial and Structural Interactions
- LRA Drawings and procedures reviewed
- Plant walkdowns performed
- Some components or portions of systems needed to be added to scope

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Regional Inspection

- Spatial interaction – No Inconsistencies Identified
- Structural interaction - No Inconsistencies Identified
- Scoping and screening - No Inconsistencies Identified

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Regional Inspection

Aging Management

- Reviewed program implementation for 22 AMPs
- Reviewed programs, evaluations, and records
  - Program procedures
  - Operational experience information
  - Corrective actions on prior plant issues
- Interviewed cognizant personnel
- Performed plant walk downs

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Regional Inspection

Aging Management

- **Aging Management Programs support conclusion that aging effects will be managed**
- **Regional Administrator's Letter To NRR Director issued January 25, 2008**

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Section 2 Conclusion

- The applicant's scoping and screening methodology consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)
- SSCs within the scope of license renewal and subject to AMR are consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)

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Section 3: Aging Management Review Results

Aging Management Programs (AMPs)

- **Total 36 AMPs**
  - **26 existing AMPs**
  - **10 new AMPs**

- **GALL Report Consistency**
  - **10 Consistent**
  - **20 Consistent with exceptions/enhancements**
  - **6 Plant Specific**

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Section 3: Aging Management Review Results

- **346 Audit Questions**
- **All Questions except two (2) were resolved**
  - **2 Questions Converted to RAIs**
  - **Fifty-five of the Questions Resulted in Revisions to the LRA**
- **25 Commitments at the End of the Audit**

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Section 3 Conclusion

- Based on its review of the AMRs and AMPs, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation

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Section 4 - TLAAs

- **OI 4.2.1-1 – Reactor Vessel Fluence (Resolved)**
  - New (Reg Guide 1.190-based) calculation submitted on November 5, 2007
  - Methodology acceptable and new value is bounded by initial value
- **OI 4.3.3-1 – Environmentally-Assisted Fatigue (Resolved)**
  - The applicant submitted Commitment #20
  - Will comply with 10 CFR 54.21(c)(1)(iii)

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Section 4 Conclusion

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

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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 that all capsules in the reactor vessel that are removed and tested meet the requirements of American Society for Testing and Materials (ASTM) E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the staff prior to implementation. All capsules placed in storage must 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.

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STAFF CONCLUSION

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

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Questions