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Plant License Renewal Subcommittee

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT LICENSE RENEWAL SUBCOMMITTEE

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THURSDAY

SEPTEMBER 20, 2018

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 1:27 p.m., Gordon R. Skillman, Chairman, presiding.

COMMITTEE MEMBERS:

GORDON R. SKILLMAN, Chairman

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR. Member

JOSE MARCH-LEUBA, Member

HAROLD B. RAY, Member

PETER C. RICCARDELLA, Member

MATTHEW SUNSERI, Member

ACRS CONSULTANT:

STEPHEN SCHULTZ

DESIGNATED FEDERAL OFFICIAL:

KENT HOWARD

ALSO PRESENT:

PHYLLIS CLARK, NRR

ALAN COX, NRR

JOE DONOGHUE, DMLR

BRYAN FORD, Entergy

SAMUEL GRAVES, Region IV*

JAMES HENDERSON, Entergy

ALLEN HISER, NRR

WILLIAM HOLSTON, NRR*

PAUL HYMEL, Entergy

LOIS JAMES, NRR

JOHN JARRELL, Entergy

BRIAN LANKA, Entergy

JAMES MEDOFF, NRR

ERIC OESTERLE, NRR

AMRIT PATEL, NRR

GORDON PICKERING, Entergy

HERBERT RIDEOUT, Entergy

MOHAMMAD SADOLLAH, NRR

DEAN SANDLIN, Entergy

EMMANUEL SAYOC, NRR

TIM SCHENK, Entergy

TODD SHERMAN, Entergy

ANDREA D. VEIL, Executive Director, ACRS

JOHN VENTOSA, Entergy

GEORGE WILSON, NRR

ALBERT WONG, NRR

MATTHEW YODER, NRR

GARRY YOUNG, Entergy

*Present via telephone

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

P R O C E E D I N G S

1:27 p.m.

CHAIRMAN SKILLMAN: Ladies and gentlemen, good afternoon. This meeting will begin. We recessed at approximately 1020. And so we are continuing the meeting that we began at 0830 this morning.

This is the meeting for the River Bend Unit 1 License Renewal Application. This meeting is a meeting of the ACRS Plant License Renewal Subcommittee. I'm Gordon Skillman. I'm chairman of the subcommittee. ACRS members that are in attendance are the same as were here this morning.

I will make one change. The meeting is open to the public. We have one set of written comments from a member of the public for this afternoon's meeting, and we may or may not deal with that later if that member decides to call in or to participate.

As before, the meeting is being transcribed. We request that all in the meeting, when they come to the microphone, please speak clearly and introduce themselves.

A telephone bridge line is established. And to preclude interruption of the meeting, we ask that the bridge line participants please maintain their phones on mute during the presentations and the

1 committee discussion. We believe that the noise that
2 we heard this morning was the consequence of an unmuted
3 line. And for those in the meeting room here, please
4 silence all of your electronic devices.
5 We're now prepared to proceed with the
6 meeting, and I call upon Joe Donoghue to please
7 introduce the second part of this meeting. Joe?
8 MR. DONOGHUE: Thanks, Chairman Skillman,
9 and again, the members of the subcommittee. And once
10 again, for those of who may not have been here, I'm
11 Joe Donoghue. I'm the Deputy Director, Division of
12 Materials and License Renewal in NRR. We, again, want
13 to express our appreciation for doing the double header
14 today to save staff resources and the licensee's
15 resources.
16 Later this afternoon, you'll hear from our
17 project manager leading the staff's evaluation -- a
18 presentation of the evaluation, Manny Sayoc. Also
19 here, as was this morning, is Dr. Allen Hiser, our senior
20 technical advisor. Eric, you already heard from.
21 He's the project's branch chief. And we have staff
22 and managers who contributed to the review from River
23 Bend in the audience to answer any questions you may
24 have. We also have Region IV staff again all lined
25 up to discuss their inspection activities related to

1 this review.

2 So again, thank you. I turn it over to

3 the Chief Operations Officer from Entergy team, John

4 Ventosa.

5 MR. VENTOSA: Good afternoon. My name is

6 John Ventosa. I'm the Chief Operating Officer for the

7 Southern Region for Entergy of which River Bend is one

8 of the sites that I have responsibility for and

9 obviously the topic of this afternoon's meeting.

10 I very much appreciate the opportunity to

11 speak to this committee this afternoon about the license

12 renewal application for River Bend. In our view, the

13 staff has conducted a very thorough but fair review

14 of our readiness for the renewed operating license.

15 For this afternoon's discussion, we have

16 with us James Henderson who's the Engineering Director

17 for River Bend, Tim Schenk who's the River Bend Reg

18 Assurance Manager, and Garry Young who's our Director

19 for License Renewal for Entergy.

20 Tim will describe our River Bend Station

21 plant status and its licensing history. James will

22 describe major equipment upgrades, completed and

23 planned, that are supporting our extended operation

24 at River Bend. And finally, Garry will discuss the

25 license renewal project itself and provide more

in-depth information on selected few topics.

Again, thank you for the opportunity to be here today for this very important milestone for River Bend. And we welcome your question and look forward to the discussion. Thank you. I'll turn the presentation over to Tim Schenk.

MR. SCHENK: And good afternoon. My name is Tim Schenk. I'm the Regulatory Assurance Manager at River Bend Station. River Bend Station is located in West Feliciana Parish, Louisiana, approximately 24 miles north-northwest of Baton Rouge, Louisiana.

It was a General Electric designed plant. Stone and Webster was the constructor. We're a Boiling Water Reactor 6 model with a GE Mark III containment and GE turbine -- General Electric turbine. Our ultimate heat sink is independent wet cooling tower. We have a closed circ water system with mechanical draft cooling towers, and we're currently licensed to 3,091 megawatts thermal with a staff of 820 individuals.

Currently, River Bend is operating at 100 percent power and is on a 24-month operating cycle. We're a Column 1 plant in the reactor oversight process, and we have a last refueling outage was in the spring of 2017. That was Refueling Outage No. 19 and Refueling

1 Outage No. 20 is scheduled for the spring of 2019.
2 CHAIRMAN SKILLMAN: Tim, what has your
3 capacity factor been for the last several cycles?
4 MR. SCHENK: The capacity factor for 2018
5 is currently 75.1 percent and 2017 is 83.1 percent.
6 CHAIRMAN SKILLMAN: The most recent is the
7 result of a refueling cycle or refueling outage?
8 MR. SCHENK: We had a planned down power
9 in early 2018 to address fuel failures at the station,
10 and that has impacted our capacity factor for 2018.
11 CHAIRMAN SKILLMAN: Okay.
12 MR. SCHENK: Some of the history of River
13 Bend Station, we received our construction permit in
14 March of 1977. Our operating license was November of
15 1985, and we commenced commercial operation in June
16 of 1986. So we were rated at that time at 2,894
17 megawatts thermal.
18 We did our first power uprate in November
19 of 2000. That's five percent power uprate. That took
20 us to 3,031 megawatts thermal. And we did another power
21 uprate in January of 2003, and it's got us to our current
22 power capacity of 3,091 megawatts thermal. Our license
23 renewal was submitted in May of 2017, and our current
24 operating license expires in August of 2025.
25 With this, I'd like to turn it over to

1 Engineering Director James Henderson to talk a little
2 bit about major equipment upgrades.
3 MR. HENDERSON: Good afternoon. My name
4 is James Henderson. I am the Engineering Director here
5 at River Bend Station. I want to go over a couple items
6 for our major equipment upgrades. What you see is
7 reflective of a long-range plan that's been focused
8 not only on equipment reliability but also safety for
9 the station.
10 A couple of the items that we have going
11 forward that we've completed already at the station,
12 the first, we've made a major upgrade to our Digital
13 EHC. That's our electrical hydraulic control system,
14 turbine controls. We have a picture going forward in
15 the presentation that we'll show to the team so that
16 you all can see the major adjustments we did there.
17 We have eliminated several single point
18 vulnerabilities on the order of greater than 90 to help
19 with the equipment reliability and long-term operation
20 of the plant. We've also done control building
21 upgrades to our control building chillers, upgrading
22 those to digital controls, looking specifically at our
23 additional monitoring, giving our operators additional
24 redundancy, and giving them the ability to identify
25 issues prior to becoming challenges for the station.

1 Also, for long-term reliability, we've
2 done recoating for underground circ water piping.
3 We've also replaced some of our obsolescence items
4 related to inverters as well as 40 Volt control circuit
5 breakers which are listed above. We've also done
6 upgrades to our normal service water cooling towers.
7 We have plate and frame heat exchangers associated
8 with our service water cooling towers. We want to make
9 sure those can support long-term operation of the plant.
10 And we've also replaced our fourth point feedwater
11 heaters associated with the station.
12 So if we go to the next slide.
13 CHAIRMAN SKILLMAN: Before you do that,
14 please. Here, you recoated your underground
15 circulating water piping. But at Waterford 3, it was
16 a one-time inspection, maybe last time when Moby Dick
17 was a minnow. So how come you're doing inspections
18 and coating here? It appears to be a very different
19 cadence than the sister plant.
20 MR. HENDERSON: Yes, for our station,
21 we've done a couple of inspections for our underground
22 piping just because we want to make sure we have that
23 long-term reliability for the station. In 2012, we
24 did a complete excavation inspection for our
25 underground piping. We also did culvert work in 2017.

1 We also took that opportunity to look at the
2 underground piping.
3 So any opportunity that we have where we
4 do excavation activities or things of that nature.
5 Because of the nature of our underground piping system,
6 we want to make sure we're doing the right thing for
7 the station.
8 CHAIRMAN SKILLMAN: Replacing the fourth
9 point heaters, is it because they were not sufficient
10 for your thermal efficiency, or were they actually
11 failing?
12 MR. HENDERSON: They were not failing.
13 This was to improve our thermal efficiency.
14 CHAIRMAN SKILLMAN: Yes sir. Thank you.
15 MR. SCHULTZ: James, what's the relative
16 time frame for the completed upgrades that are listed
17 here?
18 MR. HENDERSON: These upgrades have been
19 completed.
20 MR. SCHULTZ: No, but over what time
21 period?
22 MR. HENDERSON: Oh, it's over a five-year
23 period. So as a part of our nuclear strategic plan
24 that we did for our station, through our fleets focus,
25 we laid out specific items to go after from 2018 to

2023. And that's where you'll see a lot of our modifications or the things we're going after to improve equipment reliability.

MR. SCHULTZ: But these are completed?

MR. HENDERSON: That's correct.

MR. SCHULTZ: So five years past, you begin some of these modifications, either in engineering or in physical modification?

MR. HENDERSON: That's correct.

CHAIRMAN SKILLMAN: James, which of these upgrades was the result of a PRA review where the Entergy team said, we've got some safety benefit by making this or these changes? I'm looking particularly at the inverters and wondering if that was a material or equipment reliability change that was driven by PRA examination.

MR. HENDERSON: The inverter upgrades that we did specifically were driven based upon obsolescence for the inverters that we had in service. I'm not really sure the tie to the PRA aspect of things for the inverter.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SUNSERI: James, do you have any underground electrical cables that are subject to being covered up by water?

1 MR. HENDERSON: We do have underground
2 cables that are susceptible to being covered by water.
3 We do have preventative maintenance strategies in
4 place, not only to do monitoring. But we also have
5 solar power sump pumps to keep those wells empty.
6 MEMBER SUNSERI: Thank you.
7 CHAIRMAN SKILLMAN: So how do the solar
8 power sump pumps do at night?
9 MR. HENDERSON: That's really the piece
10 of the performance, the preventative maintenance
11 activity as well. So not just relying on the solar
12 power sump pumps, but we also have our maintenance craft
13 go out, do inspections of those water holes to make
14 sure that they're getting pumped out efficiently.
15 CHAIRMAN SKILLMAN: Thank you.
16 MR. HENDERSON: No problem.
17 MR. SCHULTZ: James, let me ask Member
18 Skillman's question a little differently with regard
19 to PRA. You talked about this as what really appears
20 to be about a ten-year program for plant improvement
21 and modification.
22 To what extent have you used the PRA in
23 providing the listing of those major improvements that
24 you're going to do? And how does the PRA team interact
25 with the modifications in terms of upgrade and update?

1 MR. HENDERSON: So when we put together
2 our nuclear strategic plan, one of the key pieces was
3 our impact to safety, our impact to risk. For example,
4 the upgrade of the control building chillers, those
5 control building chillers feed directly into our PRA
6 model, and the loss of those control building chillers
7 not only impact safety related switch gears, but it
8 also impacts the safety reliability of the main control
9 room. So those major activities that we have built
10 into our plan do have the -- our PRA team was involved
11 in making those decisions.
12 MR. SCHULTZ: That's a good example. So
13 you could go through these one at a time determine and
14 describe how they do relate to the PRA and which ones
15 most affect reliability of the facility. Thank you.
16 MR. HENDERSON: No problem. All right.
17 The next picture that you guys see, this is the graphic
18 user interface that we have for our EHC control system.
19 The visual controls are upgraded from an analog control
20 system.
21 This provides additional reliability for
22 the equipment operators, additional temp monitoring
23 as well as testing capabilities for our EHC system.
24 It has proven valuable not only for operator performance
25 but equipment reliability associated with our electric

1 hydraulic control system.

2 The next slide shows our upgrades we've

3 done for our load center breakers. Again, diagnostic

4 capability increases. The availability of the

5 breakers, all things that not only help with the

6 criminal liability but also the operator-user interface

7 associated with diagnosis as well as monitoring for

8 long-term reliability.

9 Our next slide, we've done activities

10 associated with carbon steel piping replacement. Very

11 specifically looking at our reactor water cleanup

12 system, we've gone through with some of the carbon

13 piping, removed those, replaced those with chrome moly

14 or updated with new carbon steel really to help our

15 reactor water cleanup system as it serves the function

16 to improve the chemistry and quality of our RCS. So

17 we're seeing the dividends of what we've been doing

18 here for the station.

19 MEMBER RICCARDELLA: What was the issue

20 with the old carbon steel piping? Was it flow assisted

21 or --

22 MR. HENDERSON: This was all associated

23 with our fab program.

24 So the next piece we'll talk through is

25 our major equipment upgrades. The very first are

1 turbine building chiller replacements. This is more
2 for generation and reliability for the station. Our
3 turbine building chillers not only support the turbine
4 building itself but also the cooling of our main steam
5 tunnel. So those replacements are in progress and are
6 scheduled to complete by the end of 2018.
7 We do have spent fuel pool neutron absorber
8 upgrade. I'll show you a picture going forward of that
9 upgrade that we're doing. We have inserts that we're
10 installing as prototypes to help improve not only our
11 neutron absorption but also going forward to be able
12 to use that by year 2020 for that modification.
13 The next piece, our condenser upgrade.
14 In our refueling outage '21, which will occur in 2021,
15 we plan to do a major scope on our main condenser, two
16 replacements. That's going to take place in '21. We
17 have bridging strategies from now until that time frame.
18 And in our next refueling outage, we're going to be
19 doing any current testing as well as tube cleaning and
20 all that good stuff to really make sure that we have
21 a good bridging strategy going forward to '21.
22 We've got service water cooling heat
23 exchanger refurbishment that's in progress. I did
24 annotate that earlier in our discussion. Our Fancy
25 Point switchyard upgrades, that's our offsite power

1 coming to the station, really increasing the
2 reliability there to make sure that we have a viable
3 resource of offsite power to the station.
4 Our recirc pump power cable replacement,
5 that's a part of our EQ program, getting those power
6 cables replaced so that we can improve the operation
7 of our recirc pumps.
8 And then the final two. The feedwater
9 strainer, that's directly associated foreign material
10 exclusion to the vessel. We'll have a picture later
11 in the presentation that I'll show and share with the
12 team really to make sure we have FME concerns addressed
13 for our station to prevent fuel failures and really
14 going forward to make sure that we've got long-term
15 reliability for the station.
16 And the last piece, our feedwater level
17 control system. That upgrade will also remove several
18 single-point vulnerabilities associated with our
19 feedwater level control system.
20 MR. SCHULTZ: James, with regard to the
21 switchyard upgrades, can you quantify that a bit about
22 what type of advantage do you expect to obtain by making
23 these upgrades?
24 MR. HENDERSON: So from a quantification
25 purpose, I'm not sure if I can articulate it quite well.

1 I'll tell you what we're doing for the upgrade. We're
2 going to have a total separate switchyard from the
3 switchyard that we have in place right now.
4 We have a 500 kV distribution that gets
5 stepped down to 13.8 kV for the station. So we're going
6 to totally upgrade not only the breakers and lines
7 associated with that from our transmission and
8 distribution side but also the feeders that come to
9 our station. So from a quantifying aspect, I'm not
10 sure if I could really articulate that very well.
11 MR. SCHULTZ: It's more of a changeover
12 to a different type of switchyard approach which would
13 provide additional reliability?
14 MR. HENDERSON: Yes, the way I would table
15 it, it's from an equipment reliability perspective.
16 MR. SCHULTZ: Thank you.
17 MEMBER SUNSERI: James, the power
18 reduction that Tim talked about due to fuel performance,
19 do you know if that was related to foreign material
20 yet or not?
21 MR. HENDERSON: It was related to foreign
22 material.
23 MEMBER SUNSERI: So has this been an
24 ongoing challenge for the station, hence the
25 modification?

1 MR. HENDERSON: Yes, we've had challenges
2 to the station. The first fuel failure that we
3 experienced happened in 2016 associated with a recent
4 string of fuel failures. We have the modification in
5 question for the feedwater strainers. It's really our
6 aggressive approach to making sure that we put something
7 in place to not only just perform flushing or look at
8 FME practices but really modify the plant so that we
9 put ourselves in the best position not to introduce
10 foreign material.
11 MEMBER SUNSERI: Yes, and I presume the
12 fuel assemblies themselves have some kind of debris
13 filter or something online?
14 MR. HENDERSON: They do, they do, they do.
15 MEMBER SUNSERI: So this debris is getting
16 past that?
17 MR. HENDERSON: Yes.
18 MEMBER SUNSERI: Thanks.
19 CHAIRMAN SKILLMAN: James, would you
20 please say more about the neutron absorber upgrade?
21 That is your second bullet here.
22 MR. HENDERSON: Yes, so the next slide
23 shows the neutron absorber. We currently have 60 that
24 are installed in our spent fuel pool. Basically, what
25 we're doing right now, we have the analysis from a

1 thermal perspective as well as seismic perspective.
2 And at this time, it's really monitoring to see the
3 effectiveness of those absorbers. It's aluminum
4 material is what the inserts are made of, and we're
5 going to be using that.
6 We're not taking credit for it in any of
7 our licensing basis or anything of that nature at this
8 time. It won't be until the engineering change is
9 completed as well as the full analysis of the ability
10 for our absorbers to really work. That'll be completed
11 in 2020. So we'll have all of the inserts by the end
12 of the year. We'll be able to continue to collect data.
13 And by 2020, we'll have the modification complete and
14 we'll be able to take credit for our neutron absorption.
15 CHAIRMAN SKILLMAN: Okay. So here is your
16 spent fuel pool and here you are adding hold down by
17 adding these inserts. Is this being conducted on a
18 50.59? Is this a license amendment? What is the
19 documentation that has enabled you to make, if you will,
20 a change in process?
21 I mean, this isn't something that you can
22 walk away from. You're doing it contemporaneously with
23 the requirement for the new material to provide the
24 hold down on which you depend. So what is the vehicle
25 by which you are doing this?

1 MR. FORD: This is Bryan Ford from Entergy.
2 We are going to be requesting a license amendment so
3 that we can credit the inserts for their neutron
4 absorption capability. That's an analysis change that
5 we have to get approval for. For just installing the
6 inserts, we will do that under 50.59 and we just won't
7 credit them in our neutron analysis until we get
8 approval.
9 CHAIRMAN SKILLMAN: How do you clear the
10 question on 50.59 regarding either analysis or a change
11 to the facility that might rise to the need for a license
12 amendment?
13 MR. FORD: Because we're not crediting
14 them for the analysis. So we haven't changed the
15 analysis. We're still relying upon our previous
16 analysis for it.
17 (Simultaneous speaking.)
18 CHAIRMAN SKILLMAN: Okay. I'm just
19 getting it clear. Thank you. Now I understand.
20 Thank you.
21 MR. HENDERSON: Any other questions? Our
22 next slide -- oh, go ahead. Sorry, yes.
23 MEMBER SUNSERI: Just following up on that
24 a little bit there. But these inserts must have some
25 impact other than just reactivity, right? They're

1 going to be touching the fuel assemblies. They're
2 going to change the loading of the pool. I mean,
3 seismic, material, chemistry, you're looking at of all?
4 MR. FORD: Yes, and those parts of the
5 modification are performed under 50.59. So we make
6 sure we're within the applicable margins and redo the
7 appropriate analysis to accomplish that.
8 MEMBER SUNSERI: Thank you.
9 MR. HENDERSON: The next slide for our
10 planned upgrades, this is a picture of our feedwater
11 strainer to specifically address the foreign material
12 concerns that we discussed earlier. This will be one
13 of two feedwater strainers that are installed in our
14 feedwater line directly to the vessel. It gives us
15 the last opportunity to make sure that we collect any
16 type of foreign material so that it doesn't become a
17 concern for our fuel reliability.
18 MEMBER MARCH-LEUBA: So I can understand
19 this, what are the dimensions? I mean, how big is?
20 Is it this big or this big? Is that one foot, two feet,
21 two inches in diameter?
22 MR. HENDERSON: I don't know the exact
23 diameter, but it's bigger. It's a bigger strain.
24 MEMBER MARCH-LEUBA: But the strainer
25 themselves is minuscule, right?

1 MR. HENDERSON: That's correct.

2 MEMBER MARCH-LEUBA: You're trying to

3 catch microfibers?

4 MR. HENDERSON: If you can imagine, it's

5 almost a witch's hat design where you can see the

6 differences.

7 MR. SANDLIN: I'm Dean Sandlin, the design

8 manager at River Bend. These things are about six foot

9 long and they're in 20-inch pipe. So they are actually

10 larger than 20-inch, and then we have the reducers on

11 both sides. It's probably 30 inches in diameter.

12 MEMBER MARCH-LEUBA: And the inside filter

13 is six foot long and very --

14 MR. SANDLIN: It's like a witch's hat.

15 It necks down into that, and you have about a million

16 holes in it. That's the best way to describe it. It's

17 like a witch's hat with a million little bitty small

18 holes in it.

19 MEMBER MARCH-LEUBA: And you have enough

20 pumping power to go through the pressure drop?

21 MR. SANDLIN: Yes. We've already had the

22 hydraulic analysis complete.

23 MEMBER MARCH-LEUBA: Okay. Thank you.

24 MR. SANDLIN: We didn't want to go forward

25 without that.

1 CHAIRMAN SKILLMAN: So the design pressure
2 of this is approximately 1,500 psi?
3 MR. SANDLIN: Yes.
4 CHAIRMAN SKILLMAN: And so what we're
5 seeing here is construction bolting. This is not final
6 fit of bolting?
7 MR. SANDLIN: No, that's just the shop
8 stuff right there.
9 CHAIRMAN SKILLMAN: Copy that. Okay.
10 Very good.
11 MR. SANDLIN: It'll be professional when
12 we get finished.
13 (Laughter.)
14 CHAIRMAN SKILLMAN: Okay. I'm saying,
15 wow, that's quite a mod. That's not even a 50.59.
16 (Laughter.)
17 CHAIRMAN SKILLMAN: I like that. So this
18 is basically a concept. And when this thing is snugged
19 up in place, it's got the 18 or 20-inch, inch and a
20 half high strength bolts?
21 MR. HENDERSON: Exactly, correct.
22 CHAIRMAN SKILLMAN: And she's cinched in
23 at 1,500 psi design.
24 MEMBER MARCH-LEUBA: And going back to
25 this, you have confidence that the fibers -- or I mean

1 the loose parts are coming from upstream of this filter?
2 MR. HENDERSON: Yes.
3 MEMBER MARCH-LEUBA: They're not inside
4 the vessel? They're not coming from the vessel?
5 MR. HENDERSON: Yes, the whole purpose of
6 this is to catch anything with the interface with the
7 feedwater system before it goes into the vessel, so
8 yes.
9 CHAIRMAN SKILLMAN: If I can ask, this is,
10 first of all, well done. You're protecting your fuel.
11 On the other hand, you've put in a barrier to feedwater
12 flow. So in the analysis for installation of this
13 filter, what consequence or what feature have you
14 recognized for plugging of this and its effect on your
15 core?
16 MR. SANDLIN: We've had the full hydraulic
17 analysis. We have enough capability in our feedwater
18 level control valves to provide the additional pumping
19 power we need to accommodate what we assume is the worst
20 case delta P across this filter and still maintain
21 enough flow to the core to maintain water level.
22 MEMBER MARCH-LEUBA: Is there only one of
23 these or two?
24 MR. SANDLIN: There'll be two. We have
25 two lines going into the vessel.

1 MEMBER MARCH-LEUBA: If you were --
2 MR. SANDLIN: So both lines will have one
3 of these.
4 MEMBER MARCH-LEUBA: If you were to have
5 a degree sufficient to plug it in and you have a thousand
6 holes in there, you will need another one.
7 MR. SANDLIN: We'll have differential
8 pressure instruments across it so we can constantly
9 monitor the filter as well as vibration probes on it
10 as well.
11 MEMBER MARCH-LEUBA: And after the scram,
12 you don't rely on fuel water --
13 MR. SANDLIN: That's correct.
14 MEMBER MARCH-LEUBA: -- for safety actions
15 anyway to have HPCS?
16 MR. VENTOSA: But the concern you're
17 raising was probably the primary concern in the design
18 that we needed to get a clear answer on prior to
19 installation this coming spring. So there was some
20 independent -- we had independent teams, independent
21 vendors go look at that to make sure because that is
22 the critical question. Yes, it's good that we're going
23 to protect the fuel but not causing some other effect
24 was really the --
25 CHAIRMAN SKILLMAN: So what is the failure

1 mode that you've considered?

2 MR. SANDLIN: I didn't understand your

3 question.

4 CHAIRMAN SKILLMAN: What is the failure

5 mode that you considered? What if the whole set of

6 guts carries away? You have an inside zipper failure

7 that pulls the witch's hat apart. And now, you've got

8 a forest of material entering your core.

9 MR. SANDLIN: GE did an extensive analysis

10 on the construction of the filter itself, the witch's

11 hat I'm going to call it. That's what everybody calls

12 it. And it has a structural integrity it needs to where

13 it will not fail like you're talking about, come apart

14 and then send additional FME to the core. So they've

15 got extensive analysis on that. That's another issue

16 we wanted to make sure we completely understood before

17 we went forward with this project as well.

18 CHAIRMAN SKILLMAN: And is that documented

19 in a safety evaluation or something?

20 MR. SANDLIN: The failure modes and

21 effective analysis included in our modification. GE

22 will provide that.

23 MEMBER RICCARDELLA: Is this located

24 inside containment --

25 MR. SANDLIN: No, it's in the --

1 MEMBER RICCARDELLA: -- or outside
2 containment?
3 MR. SANDLIN: -- just before it goes into
4 our steam tunnel in the turbine area.
5 MEMBER SUNSERI: And this is unique to
6 River Bend?
7 MR. SANDLIN: Yes.
8 MEMBER SUNSERI: So I guess you understand
9 the root cause of the foreign material well enough to
10 know you're -- I mean, you're putting a Band-Aid on
11 versus addressing the root cause, right?
12 MR. SANDLIN: Actually, we don't consider
13 it a Band-Aid. We want to make sure we keep all FME
14 from going to the core, and this is the last point before
15 it goes to the reactor. There's really nothing else
16 FME generator past this point going to the core. We'll
17 catch it with this filter. Anything that may happen
18 in the BOP area that will get in the feedwater system,
19 this is designed to catch it. We want to protect our
20 fuel at all costs.
21 MEMBER SUNSERI: Right. But probably so
22 does every other BWR-6 too that doesn't have this thing,
23 right?
24 MR. SANDLIN: Other BWRs may.
25 MR. VENTOSA: I can speak a little. Our

1 plans are to install it at Grand Gulf which is our other
2 BWR-6. It's just a couple years out. I don't want
3 to give you the impression that this is our fix for
4 foreign material. The root cause is work practices
5 and frankly some operational issues we had, how we set
6 valves up where we had some damage to valve internal
7 parts.
8 So we've addressed all that. We just
9 looked at the design and we felt there was still too
10 much of a vulnerability for fuel failures without taking
11 this next step.
12 MEMBER SUNSERI: Okay. That's fair.
13 MR. VENTOSA: Thanks.
14 MR. SCHULTZ: What are the maintenance
15 requirements for this? Do you have to change out the
16 filtration or flush the filtration system?
17 MR. SANDLIN: At the end of the first
18 cycle, we will take this thing out and inspect it to
19 see what kind of FME we have captured. We will
20 continuously monitor dP across it to make sure that
21 the dP doesn't exceed our hydraulic limits for pumping
22 water to the reactor to maintain the right water level.
23 But at the first cycle, we'll inspect it and we'll
24 determine what the future removal rate will be based
25 on the amount we capture.

1 MR. SCHULTZ: Good. Thank you.

2 CHAIRMAN SKILLMAN: What is the

3 anticipated radiation level when you've captured this

4 fine material in this machine?

5 MR. SANDLIN: I don't have an answer for

6 that one. We'll talk about it in our modification.

7 It's in a remote area where people just are not -- it's

8 not a routine traffic area. It's in a high radiation

9 area already.

10 MEMBER MARCH-LEUBA: I know the FME comes

11 from the balance of plant. There is no neutron flux

12 there for activation.

13 MR. SANDLIN: I can't understand.

14 MEMBER MARCH-LEUBA: All of the material

15 that it catches comes from the balance of plant,

16 correct?

17 MR. SANDLIN: It comes from the BOP.

18 Here's the feedwater system.

19 MEMBER MARCH-LEUBA: And those materials

20 are not subject to neutron fluxes that will activate

21 them. So they're very likely to not be very hot. If

22 you start catching hot material there, we'd like to

23 hear from you.

24 CHAIRMAN SKILLMAN: I'm sure we will. And

25 that's a big enough machine that if there's a lot of

1 hot material, you're going to need some super whamodyne
2 shielding around that thing.
3 MEMBER MARCH-LEUBA: While I have the
4 microphone on, I'm going to regress a little bit on
5 philosophy. I wanted to end with what Dick stated,
6 good job. Because you took positive steps to make the
7 reactor better instead of doing a whole bunch of
8 analysis that did not change the reactor. And the
9 penalty you get for that, you always get one, is that
10 you get a lot of questions about it. But let me tell
11 you, good job. Thank you for doing it.
12 CHAIRMAN SKILLMAN: Yes, this reminds me
13 of some sage advice from Benjamin Franklin who said
14 if you put all your eggs in one basket, watch that basket
15 very, very, very closely. I think this is probably
16 good practice, but I think you need to be very aware
17 of the potential to start building up small amounts
18 of material that may have found its way here and that
19 is irradiated.
20 For whatever the reason is that you're
21 having fuel challenges, it's going to collect here.
22 I've just spent enough time at nuclear power plants
23 to know any place where material can collect can become
24 a very serious radiation source. And I know you know
25 that. You don't need that sermon. But this is a big

1 trap. A big trap can get a lot of stuff and you can't
2 get near it when it gets hot. Thank you.
3 MR. HENDERSON: Our next slide shows the
4 upgrades to our feedwater level control system. For
5 perspective, our feedwater level control system has
6 had previous challenges. We've done specific items
7 to help bridge and alleviate some of those issues.
8 But the feedwater level control system is really the
9 elimination strategy for several of the single-point
10 vulnerabilities associated with the circuitry as well
11 as the workings of the feedwater level control itself.
12 So it not only provides the impact for
13 elimination of single-point vulnerabilities. It also
14 provides reliability, deals with some of the
15 obsolescence items that we have with our old system
16 and also provides our operators a full range of control
17 automatically for our feedwater regulating system to
18 help them as far as monitoring and control of the unit.
19 MEMBER MARCH-LEUBA: Was this done under
20 or planned to be done under 50.59? Because this is
21 the licensee, so it's a significant challenge.
22 MR. HENDERSON: Yes, so it is planned to
23 be done under 50.59.
24 MEMBER MARCH-LEUBA: And I'm sure you're
25 considering -- and you don't need to answer this because

1 it might go not only proprietary but classified --
2 cybersecurity.
3 MR. HENDERSON: Yes.
4 MEMBER MARCH-LEUBA: So let's make sure
5 that the staff has reviewed that you don't have a
6 penetration point there.
7 MR. HENDERSON: Agreed. Thank you very
8 much.
9 MEMBER MARCH-LEUBA: And it's not only
10 internet. USB drives, the CDs, the components, even
11 microchips.
12 MR. HENDERSON: Completely understand.
13 MEMBER BROWN: Let me echo that. Looking
14 at your slide, I haven't seen the Ovation system in
15 a while being used. It's a distributed control system,
16 if I read your acronyms correctly. And I guess my
17 question is, is that DCS connected in some type of a
18 plant network and what type of communications did you
19 have? It's referring to Jose's comment relative to
20 the access from remote sources through software-based
21 firewalls that are in some plant network.
22 On most of the new plant designs, and quite
23 frankly, on all of the new plant designs that we've
24 gone through, any connections into a network or a
25 distributed control system like this have been via

1 unidirectional hardware-based data diodes, no software
2 control one way and they're hardware configured so that
3 they can't be reconfigured externally via software
4 hackers.
5 We don't see what's going on here. If
6 you're doing it in the future, somebody may be asking
7 that question when you all come in. If it's under
8 50.59, at least it gets the antennas going in terms
9 of whether we should be asking questions about it.
10 We've raised that concern in multiple full committee
11 meetings and sessions over the last eight years. And
12 pretty much everybody has defaulted to hardware-based
13 communication one way only.
14 No problem with sending data out. You'd
15 like to get data out so people can monitor it and trend
16 and do all that type of stuff. It's just the ability
17 to come in and do any software changes via external
18 sources as opposed to having to go into the plant and
19 upload new software changes or revisions as well as
20 control access.
21 You've always got the administrative
22 controls for internal stuff. But this should be inside
23 what I call a Level 4 boundary. And you certainly don't
24 want to have to fight cybersecurity threats and always
25 being upgrading software and that firewall and access

to it get to this stuff. It'll just eat you alive. You can have a whole staff planned with it. That's all. I'm just bringing the point up.

MR. HENDERSON: No, we definitely appreciate the concern. And one of the things that we've done, this modification is scheduled for 2021; however, there are industry OE for folks that have installed this digital feedwater level control. So really capturing those lessons learned so we don't end up in a position where we're trying to --

MEMBER BROWN: Well, they probably haven't thought about this yet. Based on our conversations with other folks, it's been, well, we'll figure this out later. And they haven't really thought about the ability to limit -- I mean, the air gap is the best control that you have over ensuring nobody gets into the critical controls on this stuff.

It's not a reactor safety system, per se, in that definition like your reactor trip or safeguard systems are. But it is a vital system, and that should be treated appropriately in the same way.

MR. HENDERSON: That's a very good challenge, and we appreciate that.

MEMBER MARCH-LEUBA: Let's not forget that cybersecurity is a rapidly changing field. Just five

1 years ago, you had to deal with teenagers from high
2 school trying to steal your debt. And now you're
3 dealing with state actors with the best and brightest
4 fully funded. So you have to protect -- you have to
5 inspect any around that comes in there.
6 MR. HENDERSON: I agree.
7 CHAIRMAN SKILLMAN: Please proceed.
8 MR. VENTOSA: Then we'll turn it over Garry
9 now.
10 MR. YOUNG: Okay. Thank you. I'm Garry
11 Young, Director of License Renewal for the Entergy
12 nuclear fleet. And I'd like to give you some background
13 on our license renewal process including the approach
14 for the integrative plant assessment and for preparing
15 the license renewal application.
16 We have a dedicated corporate team working
17 on license renewal for all the Entergy nuclear plants.
18 The team has almost two decades of experience with
19 all aspects of aging management and license renewal
20 and has prepared more than a dozen license renewal
21 applications over the past several years.
22 In addition to the corporate team, a plant
23 team of River Bend experts in design, systems
24 engineering, and plant programs was established for
25 this license renewal project. The plant team provided

needed input, review, and oversight of all of the engineering and environmental reports that were created.

We had more than 40 engineering reports that were prepared to address the mechanical, electrical, civil, structural, and time limited aging analysis topics needed to prepare the application.

We used the NRC approved guidance in NEI 95-10 to prepare the project-specific procedures. These procedures have been used on our previous license renewal projects and are routinely updated based on lessons-learned industry operating experience and changes to the NRC guidance.

The site specific aging management review for River Bend were compared to the GALL report, NUREG-1801, Revision 2 as part of the application development. The individual line items in the application indicate their consistency with the GALL report aging management review results. And I'll talk more about the comparison of the aging management program with the GALL report on a later slide.

The LRA was submitted to the NRC in May of 2017. The NRC used a new review process for the River Bend application that included some efficiency improvements based on lessons learned from previous

1 NRC reviews. This has proven to be a successful effort
2 by the NRC staff and has resulted in a planned 18-month
3 review schedule rather than the typical 22-month review
4 schedule. Next slide.
5 The NRC review process culminated in the
6 River Bend safety evaluation report which was issued
7 in August of 2018 with no open items and no confirmatory
8 items. And we appreciate the extensive and thorough
9 work of the NRC staff in reaching this important
10 milestone in the license renewal application review
11 process. Okay, next slide.
12 Okay. This slide summarizes the aging
13 management programs that were credited for license
14 renewal. We have 43 aging management programs that
15 include 12 new programs and 30 existing programs that
16 are or will be consistent with the GALL report aging
17 management programs with a handful of exceptions as
18 shown on this slide.
19 So examples of the 12 new programs are the
20 buried and underground piping and tanks inspection
21 program, the non-EQ cables and connectors aging
22 management programs, one-time inspection programs, and
23 selective leeching program.
24 Some aspects of these new programs have
25 been implemented, but they are considered new programs

1 based on a significant number of changes that must be
2 made or have only recently been made to make them
3 consistent with the program descriptions in the GALL
4 report.
5 For example, the River Bend buried piping
6 program was initiated in response to the 2009 NEI
7 initiative, but significant changes are necessary to
8 incorporate the latest NRC guidance which includes
9 interim staff guidance issued in 2015. For clarity
10 in describing the program, Entergy classified it as
11 a new program that would be consistent with the program
12 described in the most recent NRC guidance.
13 In addition, most of these new programs
14 have already been implemented in other Entergy nuclear
15 plants. This allows us to ensure that implementation
16 of the River Bend aging management programs reaps the
17 benefits of lessons learned from the Entergy operating
18 experience review program and the corrective action
19 program.
20 The 30 existing programs have been compared
21 to the GALL programs, and only a few exceptions have
22 been taken. These exceptions include such things as
23 revised inspection intervals based on the River Bend
24 refueling outage schedules and referencing NRC guidance
25 regulatory guides and industry standards that are later

1 revisions than those referenced in the GALL report which
2 was published in 2010.
3 And finally, we have one plant-specific
4 program which is the periodic surveillance and
5 preventative maintenance program. This program
6 includes a variety of aging activities that could not
7 readily fit within the scope of the GALL review programs
8 without taking exceptions to those provisions.
9 And at this point, we can talk about the
10 diesel crankcase vent, if it's appropriate.
11 MEMBER BALLINGER: I have --
12 MR. YOUNG: It's the last -- oh, sorry.
13 MEMBER BALLINGER: -- another question.
14 I didn't notice it in the presentation. So in going
15 through the audit and going through the SER and going
16 through this, I could not for the life of me figure
17 out what the current status was of the shroud -- the
18 core shroud. What is the current status of the shroud?
19 MR. SHERMAN: I'm Todd Sherman from
20 Entergy. I'm the vessel internal engineer. The
21 current status of the shroud is per the BWR
22 VIP-76-1-alpha. We are classified as a Category
23 Charlie or Category C shroud.
24 MEMBER BALLINGER: Yeah, you were A, then
25 you got --

1 MR. SHERMAN: We were at the Bravo --
2 MEMBER BALLINGER: I got that right, yes.
3 MR. SHERMAN: -- prior to the last outage.
4 MEMBER BALLINGER: So I got that part.
5 But then there was -- how much crack do you have? And
6 what's the five cycle conductivity been trending?
7 MR. SHERMAN: We inspected the shroud
8 three times previous. Specifically the weld that is
9 in question is the H-4 --
10 MEMBER BALLINGER: H-4, yes.
11 MR. SHERMAN: -- beltline weld. It was
12 first inspected in 1997 with no identified cracking,
13 and that was performed from the outer diameter with
14 a little over 50 percent of the welding being inspected.
15 And then it was inspected again in 2008 from the inner
16 diameter with approximately 90 percent of the coverage
17 inspected. And it was found to have about nine percent
18 of the inspected length had flaws or cracks in it.
19 And we reinspected again in 2017 from the
20 outer diameter. We inspected once again a little over
21 50 percent of the length of the weld. And I don't
22 remember the exact figure but I believe it was between
23 40-50 percent of what was inspected was found to have
24 flaws or cracks in it.
25 MEMBER BALLINGER: So there's no fix

1 that's been applied?

2 MR. SHERMAN: Correct. We have evaluated

3 the shroud according to the flaw evaluation criteria

4 in BWR-76 and found that it still meets the maximum

5 inspection interval that there's enough structural

6 integrity maintained in the remaining uncracked

7 ligaments of the weld.

8 MEMBER BALLINGER: And that applies out

9 to the license extension length?

10 MR. SHERMAN: The next scheduled

11 inspection would be 2027 which I believe is beyond the

12 expiration of the current license.

13 MEMBER BALLINGER: Okay.

14 MR. SHERMAN: Yes?

15 MEMBER BALLINGER: And who made the

16 shroud? Who made the shroud?

17 MR. SHERMAN: I believe it's Sun

18 Shipbuilders. I'd have to look.

19 MEMBER BALLINGER: Okay. Because it

20 makes a difference.

21 MR. SHERMAN: Yes.

22 MEMBER BALLINGER: It makes a difference.

23 MR. SHERMAN: Finding the manufacturer has

24 been a big player to who gets cracked and when.

25 MR. MEDOFF: This is Jim Medoff from the

1 staff. I was responsible for the review of the BWR
2 vessel internals program. If you ask the same question
3 when the staff presents, I'll explain what I did to
4 look at it and to review everything that Todd just talked
5 about here.
6 MEMBER BALLINGER: Right. Thank you.
7 CHAIRMAN SKILLMAN: If you would like to
8 talk about the crankcase vent now, that's fine.
9 MR. YOUNG: Okay.
10 CHAIRMAN SKILLMAN: But let me tell you
11 how we got to this part of the discussion.
12 MR. YOUNG: Okay.
13 CHAIRMAN SKILLMAN: In the safety
14 evaluation, page 2-50, is the statement, Entergy
15 responded to an RAI stating the subject diesel crankcase
16 vent pipes do not have a license renewal intended
17 function since venting the crankcase is not necessary
18 for the diesel to operate under emergency conditions.
19 So this marine engineer with an unlimited horsepower
20 diesel engine license says, I'm not sailing on that
21 ship.
22 (Laughter.)
23 MR. YOUNG: Right. And we agree. That
24 statement is incorrect.
25 CHAIRMAN SKILLMAN: Thank you.

1 MR. YOUNG: Based on the comments that
2 you've provided and the statement in the SER, we're
3 preparing a supplement to that RAI response. And we
4 agree that venting of the subject diesel generator
5 crankcases is necessary. The original RAI response
6 should have more clearly stated that the vent line
7 intended function was to vent the crankcases outside
8 the diesel rooms.
9 And the potential failure of the vent line
10 due to aging effects would be loss of pressure boundary
11 which would not result in the loss of a vent function,
12 but it would result in a loss of venting outside the
13 diesel room. And that would not impact the safe
14 operation of the standby diesel generators.
15 CHAIRMAN SKILLMAN: It might mess up the
16 room, but it won't impact the diesel.
17 MR. YOUNG: Right. And therefore, we will
18 be submitting an RAI supplement to the NRC staff to
19 remove the statement that the crankcase venting is
20 unnecessary.
21 CHAIRMAN SKILLMAN: Thank you.
22 MR. YOUNG: Okay.
23 CHAIRMAN SKILLMAN: Please proceed.
24 MR. YOUNG: Okay. On this slide, on the
25 topic of commitment management and controlling the

1 commitments that we've made for license renewal,
2 Entergy has a fleet program that covers management of
3 commitments for all our nuclear plants including
4 commitments for license renewal.
5 Entergy's program is based on the
6 commitment management guidance in NEI 99-04 that the
7 NRC staff has endorsed. We have successfully used this
8 commitment management program for our previous license
9 renewal projects including projects for plants that
10 implemented license renewal commitments and are
11 successfully operating in the period of extended
12 operation.
13 For each River Bend license renewal
14 commitment, the commitment management program
15 identifies the actions needed to implement the
16 commitments and identifies the owner responsible for
17 its implementation. Assignments will include actions
18 such as a creation of implementing procedures for new
19 aging management programs and implementation of
20 enhancements to existing aging management programs.
21 And that completes my portion of the
22 presentation, and I'll turn it over to --
23 CHAIRMAN SKILLMAN: Thank you, Garry.
24 MR. YOUNG: -- John Ventosa.
25 MR. VENTOSA: So again, thank you for

meeting with us this afternoon. We truly do appreciate the challenges and borderline, I guess, advice with some of the modifications you spoke to. And we will act upon each and every comment. So we do appreciate that.

We are fully committed to continuously improving our aging management programs, but we do have strong ownership at the site of those programs. And we fundamentally sound path successfully managing the aging effects through 60 years of operations.

And in addition, Entergy is committed to continuously investing in the plants, and I think we've showed you that today in plant modifications to ensure the safe, reliable operation through the period of extended operations.

If there's no further questions, that concludes our presentation. Thank you.

CHAIRMAN SKILLMAN: John, thank you. Just to hold here, colleagues. Before we change teams, might any of you have a question for the Entergy leadership here?

MEMBER BROWN: I just wanted to amplify a perspective a little bit on that earlier comment. This system is an in-plant system and is largely within a boundary. But if you -- even though you probably

1 don't have them defined this way, it would be called
2 a Level 4 security from an access standpoint.
3 This is really not a programmatic issue
4 as much as it is a control of access -- remote access
5 issue. And my fundamental concern I've tried to convey
6 is that while my statement is not 100 percent correct,
7 almost all cyber issues and upgrades and revisions are
8 reactive.
9 In other words, you are always responding
10 to what has already killed somebody else. And nobody
11 is out there sitting there, oh, gee, the guy could make
12 access this way or that way. You're not preventing
13 all circumstances. There are always holes. Now, that
14 is not exactly -- there are some obvious holes that
15 you can plug. But there is the non-obvious ones that
16 you can't, and that's where all the problems come about.
17 That's why I would encourage you -- I was
18 going to ask the question on your circuit breaker.
19 I presume those are digital-based circuit breaker
20 controls. Same issue as if you had those connected
21 into a distributed control system or they're via part
22 of the big network that has direct access from external
23 sources.
24 Such that if you do, if some of them --
25 I guess if you got a transmission guy that has to operate

1 some of those breakers for some reason, you don't have
2 any choice. More than likely, that's where all of your
3 internal control breakers, the big ones or small ones.
4 It's best to just keep them totally isolated from the
5 outside world.
6 It wasn't problem in the old days when you
7 turned a switch and a little current went and tripped
8 a relay. And the words we used to have in the documents
9 like control of access and things like that for
10 instrumentation control were pretty fundamentally
11 based on the old analog world that we lived in. And
12 that's the whole thing has changed now relative to the
13 ability to get to a system to do things with them.
14 So I mean, it's just a little more
15 perspective. That's all I'm -- obviously, I'm not
16 trying to tell you, you can't do them. And that's not
17 the point. It's just to be very, very thoughtful about
18 how you allow that access. You can hurt yourself in
19 the long run.
20 MR. VENTOSA: No, we definitely appreciate
21 the insight.
22 MEMBER BROWN: Thank you.
23 MR. SANDLIN: This is Dan Sandlin again.
24 I want to talk to your point. The BWR level control
25 upgrade will be an extension of the existing Ovation

1 system and has already been inspected by Sam -- I can't
2 remember. He was talking on the -- we were the first
3 plant to be cybersecurity inspected, and that Ovation
4 system was already there. They looked at it in depth
5 and found no issues. We do have data diodes. You can't
6 talk into it. You can talk out, but you can't talk
7 in. It's part of our process.
8 MEMBER BROWN: Are they hardware data
9 diodes or they're --
10 MR. SANDLIN: Yes.
11 MEMBER BROWN: -- software? In other
12 words, it's a physical hardware? You might have
13 something that can give you a transmitted receive, but
14 you disconnect the receive. That's the point.
15 MR. SANDLIN: They can't get into us.
16 MEMBER BROWN: Okay. That's fine.
17 You've thought it then.
18 MR. SANDLIN: We did, yes.
19 MEMBER BROWN: Just saying somebody has
20 reviewed Ovation. I remember this has been several
21 years ago when I saw it. And it definitely had
22 bidirectional -- the ability to be communicated
23 bidirectional. And you have to physically make it --
24 you want to make it physically impossible to do so.
25 So thanks.

1 MR. SANDLIN: For the digital breakers,
2 they are independent, standalone. There's no
3 connections to it.
4 MEMBER BROWN: No connections? Okay.
5 Excellent, thank you.
6 CHAIRMAN SKILLMAN: Thank you, Charlie.
7 Yes sir, thank you. Colleagues, any other comments
8 for the Entergy team? If not, let's swap teams and
9 keep on going. Joe, your team is up.
10 (Pause.)
11 CHAIRMAN SKILLMAN: Manny, whenever
12 you're ready, please.
13 MR. SAYOC: Is that on?
14 CHAIRMAN SKILLMAN: Yes sir, yes.
15 MR. SAYOC: Again, good afternoon,
16 Chairman Skillman and members of the License Renewal
17 Subcommittee. My name is Emmanuel Sayoc, and I am the
18 project manager for the River Bend Station, Unit 1
19 License Renewal Safety Review.
20 We are here today to discuss the staff's
21 review of RBS license renewal application, or LRA, as
22 documented in our safety evaluation report issued
23 August 16, 2018. Joining me here at the table are Dr.
24 Allen Hiser, the LR Senior Technical Advisor, and Mr.
25 Albert Wong, Senior Project Manager for the LR who will

1 be running the slides.

2 Mr. Samuel Graves, Senior Reactor

3 Inspector from Region IV is on the phone and will discuss

4 the 71002 inspection. Sitting in the audience and on

5 the phone are members of the technical staff who

6 participated in the review of the national application

7 and conducted the various audits. Next slide, please.

8 I will begin the presentation with a

9 general overview of the staff's review. Next, Mr.

10 Graves will present the 71002 inspection results. I

11 will then present the main sections of the safety

12 evaluation report. Next slide, please.

13 On May 25, 2017, Entergy Louisiana, LLC

14 and Entergy Operations, Inc. -- collectively referred

15 to as Entergy or the applicant -- submitted an

16 application for the renewal of RBS operating license

17 for an additional 20 years. The RBS license renewal

18 review process was optimized from previous license

19 reviews including the Waterford review that you heard

20 about this morning.

21 In particular, the RBS license renewal

22 review used an 18-month schedule with expanded audits

23 and a streamlined SER that was issued in August 2018.

24 This process also served as a pilot program for the

25 staff review of subsequent license renewal

applications.

Consistent with prior license renewal reviews, the staff conducted three centered audits as shown in the slide. The operating experience audit was conducted at local offices that are within walking distance with NRC headquarters.

The scoping and screening audit and the regional site one and two inspection was done onsite at River Bend.

The AMP audits were expanded to about ten weeks and included document reviews via electronic portal and applicant interviews conducted from the NRC headquarters. There was a portion done onsite at River Bend to perform system walk downs.

During the operating experience audit, the team conducted an independent search of the plant operating experience for information to determine, "A", whether previously known or recurring aging effects were identified, and "B", whether in light of the plant operating experience, the applicant's LRA aging management program can adequately manage the associated aging effects. The operating experience audit results were documented in a report dated January 8, 2018.

During the scoping and screening methodology audit, the team reviewed the applicant's

1 administrative controls governing the scoping and
2 screening methodology and the technical basis for
3 selected scoping and screening results. The scoping
4 and screening methodology audit report results were
5 documented in a report dated January 8, 2018.
6 During the AMP audits, the team examined
7 applicant's aging management programs and related
8 documentation to verify the applicant's programs were
9 consistent with those described in GALL report and with
10 plant conditions and operating experience. The staff
11 reviewed the 43 AMPs outlined in the LRA and documented
12 the results in a report dated January 29, 2018.
13 Mr. Graves will discuss the activities of
14 the 71002 inspection in a few minutes. Next slide.
15 As discussed before, the RBS final SER was
16 issued on August 16, 2018 with no open items or
17 confirmatory items. During the staff's in-depth
18 technical review of the LRA, a total of 119 RAIs were
19 issued, 15 of which were follow-up RAIs. The final
20 SER will be published as a NUREG following issuance
21 of the new license.
22 I will now direct the presentation to Mr.
23 Graves who will discuss the inspection activities and
24 results associated with this LRA review. Next slide.
25 MR. GRAVES: Thanks, Manny. Good

1 afternoon, subcommittee members. My name is Sam
2 Graves. I'm a senior reactor inspector in the Region
3 IV office, and my branch is responsible for performing
4 license renewal inspections. This inspection involves
5 four experienced regional inspections with expertise
6 in electrical, civil, nuclear, and mechanical
7 engineering.
8 The team was onsite February 26th through
9 March 19th, and the inspection report was issued on
10 May 7th. The team reviewed the scoping and screening
11 of components, walk down accessible areas and reviewed
12 25 aging management programs of which 6 were new
13 programs and 19 were existing.
14 The team walked down numerous structures,
15 systems, and components to assess the adequacy of the
16 applicant's license renewal boundaries, material
17 condition, and conformance with their application and
18 the Generic Aging Lessons-Learned report. Next slide,
19 please.
20 From the walk down, the team determined
21 that the material condition of the facility was very
22 good with one exception that the applicant was
23 addressing related to some corrosion on piping located
24 in the below ground level piping tunnels.
25 The environment in the pipe tunnels is very

1 humid, and the pipes were relatively cold resulting
2 in a lot of condensation formation and some subsequent
3 surface corrosion. The applicant was in the process
4 of remediating the pipe to remove the existing surface
5 corrosion and applying an oxy type paint.
6 For the surface water integrity program,
7 the applicant had been performing heat exchanger
8 inspections in their service water system for many years
9 but had not considered crediting these existing
10 inspections as part of their aging management program.
11 The applicant agreed to include the inspections they
12 were already performing into their plant-specific
13 Periodic Surveillance and Preventive Maintenance aging
14 management program. Next slide, please.
15 So in summary, the team concluded that the
16 applicant performed the scoping and screening in
17 accordance with the rule. The team found that the
18 information was easily retrievable, auditable, and
19 consistent with the rule. The team verified that the
20 existing programs were effective in managing aging
21 effects, and the new programs provided reasonable
22 assurance that aging effects will be managed. The team
23 also verified that the applicant had a process to track
24 the completion of enhancements and the development of
25 the new programs.

1 So based on the inspection results, the
2 team had reasonable assurance that the programs in place
3 or planned as described in their commitment table will
4 manage the aging effects and ensure the intended safety
5 functions of systems, structures, and components within
6 the scope of the rule.
7 Are there any questions for me?
8 CHAIRMAN SKILLMAN: Sam, thank you. I do
9 have several questions. This is Dick Skillman.
10 MR. GRAVES: Yes sir.
11 CHAIRMAN SKILLMAN: On page 8 of your
12 inspection report, in the middle of the page, the text
13 is as follows. This is regarding bolting integrity.
14 It is Bravo, 1, 2, and it's Roman IX, M18 is the program.
15 The sentence that I'm sentence that I'm
16 focusing on is this sentence: The second exception
17 related to the inaccessible services of the suppression
18 pull suction strainer submerged bolting. The
19 applicant requested to conducted visual inspection once
20 every ten years instead of once every refueling cycle.
21 The applicant planned to verify the bolting was hand
22 tight.
23 That doesn't make sense to me. What in
24 the world does that mean?
25 MR. GRAVES: Well, sir, my understanding

1 is that the bolts are normally drilled and lock wired
2 in place. So if they have demonstrated any loosening,
3 the manipulation with your hands would be able to
4 determine that. And from there, that would lead to
5 remedial action.
6 If I remember correctly discussing it with
7 a team leader, they weren't really trying to communicate
8 that you wouldn't put any torque on it. You'd just
9 screw it down mechanic tight or hand tight. That, I
10 don't think, was what they intended to try to
11 communicate in that section.
12 CHAIRMAN SKILLMAN: Just hold on here.
13 Let's get a licensee person who understands hand tight
14 versus torque to 90 or 250-foot pounds and find out
15 what the answer is. Can someone from Entergy tell us
16 what hand tight means on these very important flanges?
17 MR. SANDLIN: I believe the intent -- this
18 is Dean Sandlin. I'm sorry. The intent was they were
19 torqued originally to the torqueing requirements. And
20 if they had come loose, it would be secured with the
21 tie wraps -- I mean, the lock wire that we put on anything
22 over the pool area. And if they had come loose, we'd
23 be able to detect by the diver going down and seeing
24 if the connection was loose.
25 CHAIRMAN SKILLMAN: That's fair enough.

1 That's what Sam just explained too. That's all right.
2 It's just the only evidence that the ACRS members of
3 these inspections is what was provided in the SER.
4 And please know that my team members and I read this
5 stuff very carefully so that we discharge our
6 responsibilities as we should. So thank you.
7 Sam, I've got another one.
8 MR. GRAVES: Yes sir.
9 CHAIRMAN SKILLMAN: So on your inspection
10 report, pages 10 and 11, and the wording that caught
11 my attention is this wording at the top of page 11.
12 This is regarding enhancements on one of the programs.
13 And what is important is the way this text reads.
14 The text reads, at least two years prior
15 to entering the period of extended operation, the
16 applicant planned to develop a set of fatigue usage
17 calculations that consider the effects of the reactor
18 water environment for a set of the most limiting reactor
19 coolant system components, considering all stress
20 components for environmentally assisted fatigue, and
21 use the maximum temperature if the average temperature
22 is below the threshold.
23 And they're going to do all of that two
24 years before the PEO and they plan to develop a set
25 of calculations. That almost sounds like a commitment

1 for something that just might happen if it happens at
2 all. So I'm wondering what is the firmness of this
3 commitment.
4 MR. GRAVES: Well, sir, that's a good
5 question. I cannot answer the firmness of the
6 commitment. That would certainly be something to
7 direct to the licensee. But our impression was that
8 that was their intention.
9 CHAIRMAN SKILLMAN: Fair enough. Now,
10 we're going to ask someone from the licensee to tell
11 us what it means.
12 MR. MIN: Yes, this is Seung Min with the
13 staff first. And then if I address that question that
14 there is a difference between the current license basis
15 particularly on these requirements mainly based on
16 appendix -- I'm sorry, Section III of ASME code.
17 Before the fatigue analysis, TLA. If we
18 take TLA for the period of extended operation,
19 environmental effects need to be considered. That
20 portion either dealt between the PEO fatigue analysis
21 and the CLB fatigue analysis for to fill in the gap.
22 The applicant identified the enhancement to implement
23 to identify the locations involved environmentally set
24 fatigue analysis. That's all.
25 CHAIRMAN SKILLMAN: Thank you. Can

1 someone from Entergy confirm that this is a commitment
2 that's embedded in your commitment list?
3 MR. COX: Yes, this is Alan Cox. I'm
4 looking at the commitment list in the SER, and
5 Commitment No. 11 is on the fatigue monitoring program.
6 It says, to enhance it as described in LRA Section
7 A.1.18. And in that section, it discusses this. And
8 the due date for this commitment is enhancement to
9 develop a set of fatigue uses calculations prior to
10 August 29, 2023. And that's the two years prior to.
11 So it is a formal commitment as documented in the SER.
12 CHAIRMAN SKILLMAN: Yes sir. Alan, thank
13 you very much. Thank you.
14 Sam, that concludes my comments. Thank
15 you for a very thorough inspection, and that ends my
16 questions on the inspection report.
17 Manny, back to you.
18 MR. SCHULTZ: Just one. Sam, I think --
19 this is Steve Schultz. This may be a comment more than
20 a question, but I'd like you to respond. On your last
21 page of discussion, you've indicated that in performing
22 the audit at the site, the information was easily
23 retrievable and auditable. And then you follow that
24 with a conclusion that existing programs effectively
25 managed aging effect.

1 And my impression is in reading the audit
2 reports, not only the documentation that you've been
3 able to provide and following through the track of
4 inspection that you've accomplished at the site that,
5 in fact, these summary statements are very accurate.
6 You provide a lot of good information in each of the
7 areas to support your conclusions that are presented
8 in the audit.
9 I also notice as I look through the listing
10 of items that you draw from the documentation at the
11 site that there seems to be in many of the areas that
12 you inspect, if I look at the time history of what you
13 pulled as documentation, that there seems to be an
14 improvement in plant condition, at least based on the
15 chronological reporting of events.
16 Am I drawing a proper conclusion, or did
17 I just happen to see things that looked like they
18 demonstrate that trend?
19 MR. GRAVES: I can tell you my
20 communication with the team leader, he was actually
21 very favorably impressed with the material condition
22 of River Bend Station. Greg Pick was the lead inspector
23 on this, and he's done a number of these inspections
24 throughout the region. And he said that this was the
25 most impressive material condition he had seen. So

1 I think your conclusions, not 100 percent sure how you
2 got there, but that is exactly the conclusion he came
3 to as well.
4 MR. SCHULTZ: Thank you. I'm not taking
5 that as a full confirmation. I just wanted to talk
6 with you about it and get your impressions.
7 MR. GRAVES: I know we very much appreciate
8 that. We try to make the inspection reports thorough
9 and we try to use language that will communicate the
10 issues. And as inspectors, if we say something is
11 adequate, that's typically a pretty tall compliment
12 for an NRC inspector.
13 MR. SCHULTZ: I understand that.
14 MR. GRAVES: Yes sir. So that's why some
15 of the wording is the way it is. But yes sir, thank
16 you very much.
17 MR. SCHULTZ: Well, your document says --
18 the slides we have say that the material condition is
19 good. I think you amplified that by saying it was very
20 good when you made your report today.
21 MR. GRAVES: Yes sir, I did.
22 MR. SCHULTZ: But I'm not taking that --
23 I'll take it as you've just stated it. I appreciate
24 that. Thank you very much.
25 MR. GRAVES: Yes sir, thank you. Manny,

1 I think I'm finished. Your turn.

2 MR. SAYOC: Thank you, Sam. We're on

3 Slide 8. In the next few slides, I will present the

4 results of the staff's review of the LRA as described

5 in the SER. SER Section 2 described scoping and

6 screening of structures and components subject to aging

7 management review. The staff reviewed the applicant's

8 scoping and screening methodology, procedures, quality

9 controls applicable to the LRA development and training

10 of project personnel.

11 The staff also reviewed the various

12 summaries of safety-related systems, structures, and

13 components or SSCs, non-safety SSCs affecting functions

14 of safety-related components and SSCs relied upon to

15 perform functions applicable to River Bend in

16 compliance with the emissions, regulations for fire

17 protection, environmental qualification, station

18 blackout, and anticipated transients without scram.

19 Based on the review, the results from the

20 scoping and screening audit, and additional information

21 provided by the applicant, the staff concludes that

22 the applicant's scoping and screening methodology and

23 implementation was consistent with the standard view

24 plan and the requirements of 10 CFR Part 54. Next

25 slide, please.

1 CHAIRMAN SKILLMAN: Manny, let me ask one
2 or two questions that is on SER Section 2. On SER,
3 page 2-7, at the bottom of the page, the NRC writes
4 this sentence. It is in response to non-safety-related
5 SSCs providing functional support for safety-related
6 SSC functions. And this is the sentence that I
7 challenge.
8 MR. SAYOC: Okay.
9 CHAIRMAN SKILLMAN: One safety-related
10 SSC supporting 10 CFR 50.54(a)(1) was identified, the
11 plant drains system, which supports maintaining
12 suppression pool inventory for use following a LOCA.
13 And the conclusion of that section is, based on the
14 above, the methodology for identifying non-safety SSCs
15 whose failure could prevent satisfactory
16 accomplishment of the intended functions is in
17 accordance with 50.54(a)(2).
18 It sounds as if this is the single one and
19 only SSC. Is that an accurate conclusion?
20 MR. SAYOC: If I am understanding your
21 question, you're referring to the plant drains.
22 CHAIRMAN SKILLMAN: Yes, it sounds as if
23 that is the single one and only and there isn't anything
24 else. And that doesn't make sense. So could it be
25 it's just the wording of your SE? Or is this an example?

1 And failing the words, an example, one would be led
2 to believe it's just this single and only one system?
3 MR. HISER: This is Allen Hiser of the
4 staff. I'd be surprised if this is the only system
5 that falls under this category. We can go back and
6 take a look at the SER and bring back to you any
7 clarification.
8 CHAIRMAN SKILLMAN: If you would, a
9 clarification. And it is page 2-7 of the safety
10 evaluation. And it is the last and final sentence on
11 that page.
12 I've got one other comment on Section 2.
13 This is an RAI response to RAI B.1.10-2. And this
14 has to do with the internal portions of the SLICK lines.
15 And the safety evaluation says, the internal portions
16 of the SLICK lines don't matter because they've boosted
17 the boring concentration 25 percent. And that leads
18 to the impression that the SLICK lines can fall apart
19 and you can still poison the core.
20 Well, it sounds like a dandy argument for
21 reactivity, but it doesn't sound like much of an
22 argument for structural integrity inside the reactor
23 vessel. So I'm wondering what the safety evaluation
24 really evaluated.
25 MR. HISER: Which page was that again?

1 CHAIRMAN SKILLMAN: That is on SER, page
2 2-21 at the bottom of that page.
3 MR. SAYOC: I think that's from the staff,
4 Jim Medoff.
5 MR. MEDOFF: So, this was a matter that
6 was looked at by the staff, Mr. Summerson of DSS and
7 myself, as part of the vessel -- I'm sorry. This is
8 Jim Medoff of the staff. This was as an aspect of the
9 application that was investigated by the both of
10 Division of Safety and Safeguards and by the Division
11 of Materials and License and Renewal. It deals with
12 the way the vessel internals program manages the standby
13 liquid control system to manage an ATWS event.
14 In the approved report, the EPRI BWR VIP
15 has concluded that the internal portions of this SLICK
16 system did not need to be age managed because even if
17 it broke, even if you had a through-all crack and the
18 component fail and you had a blob of boron water coming
19 into the reactor near in the lower plenum, what would
20 happen is eventually the reactor coolant would start
21 to heat up and then it would promote some natural
22 circulation to get the boron up towards the core where
23 you needed it.
24 And then that would start to shut down the
25 reactor with the boron inventory. And then it would

1 start to cool down and instead you would get this
2 reiterative cycle to make sure you got boron cooling
3 in the core. For that reason, Entergy did not include
4 the internal portions of volume and scope and we
5 wondered about that. We did think about it.
6 And so we basically asked them a question.
7 We wanted to assume. Let's assume that the VIP report
8 is it's questionable, I think, that it really occurred.
9 We asked the question, would you really get adequate
10 mixing if the line broke? Because it's serving a safe
11 shutdown function.
12 From that perspective, we asked a question
13 on that. And we had a teleconference, and Entergy had
14 replied that they had something in their design basis
15 that would account for inadequate mixing which was our
16 big issue on the review.
17 What we did is we went back to the FSAR
18 in the design basis. We did find a statement in their
19 ATWS evaluation and their SLICK system operational
20 statements that said they included an additional 25
21 percent of boron into the boron control tank which would
22 account for any questions of inadequate mixing which
23 alleviated our concern with the potential through all
24 flaw and warming.
25 CHAIRMAN SKILLMAN: How did that alleviate

1 your concern?

2 MR. MEDOFF: Because the question is

3 whether the mixing argument in the approved VIP report

4 would be okay. We had a big discussion with this with

5 the folks in DSS. The conclusion was the additional

6 25 percent for Entergy should be sufficient to address

7 any questions on whether they put adequate mixing if

8 you had a through-all flaw in the line.

9 CHAIRMAN SKILLMAN: And is all of that

10 documented?

11 MR. MEDOFF: Some of it's documented in

12 the scoping section. Some of it's documented in the

13 review of the AMP and in the audit report. So there's

14 another section which would be the Section 3, a section

15 for the reactor vessel internals AMP that should discuss

16 that as well in one of the action item responses.

17 CHAIRMAN SKILLMAN: Thank you. Go ahead,

18 Manny. Thank you.

19 MR. SAYOC: SER Chapter 3 in its

20 subsections covers the staff's review of aging

21 management programs for managing aging in accordance

22 with 10 CFR 54.21(a)(3). Chapters 3.1 through 3.6

23 include the aging management review items in each of

24 the general system areas within scope of license

25 renewal.

1 For a given aging management review, the
2 staff reviewed the item to determine whether it is
3 consistent with the GALL report. If an aging
4 management review is not consistent with the GALL
5 report, then the staff reviewed the applicant's
6 evaluation to determine with the applicant has
7 demonstrated assurance that the effects of aging will
8 be adequately managed so that intended functions will
9 be maintained consistent with the current licensing
10 basis for the period of extended operation. Next
11 slide.
12 The LRA describe a total of 43 aging
13 management programs: 11 new, 31 existing, and one
14 plant-specific. This slide identifies the applicant's
15 disposition of AMPs on the left column and the final
16 disposition of AMPs as a result of the staff's review
17 on the right column.
18 One plant-specific AMP was provided, all
19 with the exception of the plant-specific AMP were
20 evaluated by the staff for consistency with GALL report,
21 Rev. 2. Overall, the staff concluded that 22 AMPs were
22 consistent with the GALL report. These included 12
23 new programs and 10 existing programs.
24 In addition, 13 programs were consistent
25 with enhancements, 2 consistent with exceptions, and

5 were consistent with enhancements and exceptions. RBS has one plant-specific program. Later in the presentation, we will discuss an existing program that was replaced and thus became a new program. Next slide, please.

Section 4 identifies time-limited aging analyses, or TLAAs. Section 4.1 documents the staff's evaluation of the applicant's identification of applicable TLAAs. The staff evaluated the applicant's basis for identifying those plant-specific or generic analyses that need to be identified as TLAAs and determine that the applicant has provided an accurate list of TLAAs as required by 10 CFR 54.21(c)(1).

Sections 4.2 through 4.7 document the staff's review of applicable TLAAs as shown. Based on its review of the information provided by the applicant, the staff concludes that either the analysis remained valid for the period of extended operation, the analysis has been projected to the end of period of extended operation, or the effects of aging on the intended functions will be adequately managed for the period of extended operation as required by 10 CFR 54.21(c)(1)(i), (ii), and (iii) respectively. Next slide, please.

Since we have no open or confirmatory

1 items, we wanted to highlight a few areas of interest
2 in our review. The first area is related to the reactor
3 vessel of neutron fluence TLAA. In its review, the
4 staff identified an issue with the methodology used
5 to calculate the 60-year neutron fluence values -- I'm
6 sorry, fluence levels for the reactor pressure vessel
7 RPV.
8 The LRA stated it used an NRC-approved
9 methodology to determine the neutron fluence values.
10 However, the staff noted that the staff approved
11 methodology is not applicable to RPV beltline
12 components above the active fuel region. The staff
13 therefore issued an RAI requesting justification on
14 how the methodology was expanded to incorporate the
15 qualified above core calculation model.
16 In its response, Entergy provided
17 additional core design conservatisms that justified
18 neutron fluence values for the RPV, including the
19 components above the active fuel region.
20 Specifically, the applicant stated that the
21 conservatisms in this methodology accounts for
22 potential uncertainties in the above core water
23 densities and considers the bounding power-flow state
24 point that leads to higher neutron fluence.
25 These conservatisms provide sufficient

1 demonstration that the 60-year neutron fluence values
2 in the LRA are conservative and meet the intent of
3 guidelines in Reg. Guide 1.190 which demonstrates --
4 sorry, which describes methods and assumptions
5 acceptable to the NRC for calculating a neutron fluence.
6 The staff therefore concluded that
7 associates TLAAs were demonstrated to be acceptable
8 for 10 CFR 54.21(c)(1)(ii). Next slide.
9 MR. SCHULTZ: Emmanuel, one question
10 associated with the vessel neutron fluence. And I
11 guess it really occurred to me to look at this further
12 with respect to the evaluations we discussed this
13 morning at Waterford in this area.
14 The SER talks about, just as it is on the
15 slide here, a conclusion that is based upon these
16 conservatisms. Did the staff do any audit calculations
17 or anything to demonstrate that what has been reported
18 as conservatisms are validated or is there some
19 experience that the staff has that led you to agree
20 with the conclusions that were being presented? That's
21 one question.
22 The other question I have is, was this
23 information presented by the vendor or was it performed
24 and presented by the applicant?
25 MR. SAYOC: Yes sir. I appreciate the

1 question. We have Mr. Amrit Patel that I think can
2 better answer your question.
3 MR. SCHULTZ: Thank you.
4 MR. PATEL: I'm Amrit Patel from the tech
5 staff. So the staff didn't base this on anything from
6 an audit. So there were no staff performed
7 calculations to verify that. It was based solely on
8 our information submitted through RAI responses based
9 on staff questioning of the qualification and
10 validation of the method for these above core region.
11 So the majority of that response is
12 proprietary, so that's kind of why it's couched in terms
13 of conservatisms. But there are several layers of
14 conservatism in the qualification. So a lot of that
15 is focused on the above core voiding distribution which
16 has a direct influence on the flow -- direct impact
17 on the fluence. But it's purely the applicant's
18 assessment or analysis.
19 MR. SCHULTZ: You're right. I didn't
20 appreciate the proprietary nature of the calculations
21 and the results thereof. So now, I better understand.
22 Because recently, that is since this morning, I was
23 looking at the SER particularly. So now, I understand
24 why the details aren't there. I had looked at the RAI,
25 and I know what details are there, the RAI response.

1 The other question I had with regard to
2 the SER presentation of information is that there was
3 an error noted and it was pretty late in the game, in
4 August, associated with the effect of pull power year
5 calculation that had been done. I didn't know which
6 direction that error was made. I presumed it was an
7 issue where you needed to demonstrate more fully the
8 ability of the conservatisms to account for the final
9 results.
10 MR. PATEL: So my understanding, I wasn't
11 directly involved in the finding. But if my memory
12 serves me right, it was related to a transposition
13 error.
14 MR. SCHULTZ: Yes.
15 MR. PATEL: Right. And I do recall it was
16 quite minor. The relative change in -- yes, if you
17 want to --
18 MR. SCHULTZ: Only if you're not
19 performing the calculation.
20 MR. PATEL: Right, but I think the way --
21 yes, if I understand, I think -- oh, can you speak to
22 it? Okay.
23 MR. SCHULTZ: I'd appreciate that. Thank
24 you.
25 MR. SHERMAN: Todd Sherman from Entergy.

1 So unfortunately, the error that was found was in the
2 less conservative direction. And for the past
3 operating cycles, the vendor modeled them as-is. But
4 for the future projected cycles, they added on an
5 additional ten percent conservatism to account for
6 different core-to-core cycle variations.
7 And so the error that was found was
8 approximately .72 EEPY that were not added onto that
9 irradiation past cycle.
10 MR. SCHULTZ: A cycle is 10 to 11.
11 MR. SHERMAN: That is correct.
12 MR. SCHULTZ: Yes.
13 MR. SHERMAN: And so the ten percent margin
14 which was originally 2.866 of EEPY was reduced to 2.086.
15 So it just reduced the overall margin from the future
16 projected cycles irradiation.
17 MR. SCHULTZ: That helps a lot. Thank
18 you.
19 MR. SAYOC: Okay, thank you. The second
20 area of our review that we would like to highlight is
21 related to the use of polymeric material in high voltage
22 insulators. The staff noted high voltage insulators
23 made of polymeric material utilize in the recovery path
24 transmission lines. The applicant stated that
25 polymeric high voltage insulators were installed in

1 2008. However, the LRA only lists porcelain high
2 voltage material.
3 GALL has addressed porcelain high voltage
4 insulators but not polymeric high voltage insulators.
5 The staff noted that polymeric high voltage insulators
6 have unique aging mechanisms that can result in aging
7 effects such as loss of insulation resistance and loss
8 of material. Animal excrements containing chemicals
9 such as phosphates, ammonia, nitrates at present can
10 contribute to and accelerate aging as well.
11 Thus, the staff issued an RAI requesting
12 inclusion of the polymeric high voltage insulators and
13 evaluation of this site-specific material-evaluation
14 combination. The applicant responded by including the
15 polymeric high voltage insulators and provided an
16 evaluation of the pertinent aging mechanisms and aging
17 effects.
18 The applicant incorporated periodic
19 preventive maintenance and inspections to be relied
20 upon to monitor potential age-related degradation.
21 The staff concluded that inclusion of the polymeric
22 high voltage insulators in the LRA and periodic
23 preventive maintenance and inspections are acceptable.
24 Next slide, please.
25 Another area of review that we would like

to highlight pertains to Entergy's new neutron absorbing material program. The staff found this new program to be consistent with GALL Report AMP XI.M40 and will adequately manage the effects of aging.

This is a replacement for the Boraflex monitoring program that was previously credited for neutron absorbing material. Due to degradation, Boraflex material currently in the spent fuel pool will not be able to maintain required sub-criticality margin into the period of extended operation.

Entergy plans to submit an LAR for SNAP-IN inserts by the end of the third quarter of 2018. Installation is scheduled for June through October 2019, and aluminum boron-carbide neutron absorbing material will be installed prior to the PEO. The staff finds these acceptable. Next slide, please.

CHAIRMAN SKILLMAN: Manny, what examination has the staff given to the new SNAP-IN material and its survivability in the spent fuel pool?

MR. SAYOC: Okay. We have the staff.

MR. YODER: Matt Yoder from the NRC staff. We previously reviewed and approved let's say on the order of ten other license amendments for this material. So it's well documented and well tested.

CHAIRMAN SKILLMAN: Okay, thank you.

1 MEMBER MARCH-LEUBA: Okay. Excuse the
2 question then. What degradation was found on the
3 Boraflex?
4 MR. YODER: So again, this is Matt Yoder
5 from the staff. Boraflex material, essentially, it's
6 a polymer and it's dissolving. It's well documented
7 there had been multiple information notices, generic
8 letters, et cetera documenting this phenomena.
9 MEMBER MARCH-LEUBA: I guess you answered
10 my next question is it's a generic issue. And you're
11 saying there was a generic letter.
12 MR. YODER: Most plants that have this
13 material have done away with it either by replacing
14 with the SNAP-INs or using a geometric approach,
15 spreading the fuel out, if you have the room to do so.
16 MEMBER MARCH-LEUBA: Thank you.
17 MEMBER BALLINGER: When they change out
18 the Boraflex, the lifetime goes from essentially very
19 small to essentially infinity with the new material.
20 So it's a huge difference.
21 CHAIRMAN SKILLMAN: But let me ask this.
22 With the dissolution of the Boraflex, is the fuel that
23 is in the pool that is reintroduced to the core injured
24 in any way?
25 MR. YODER: Matt Yoder from the staff.

1 There's no impact on the fuel.

2 CHAIRMAN SKILLMAN: How do you know?

3 MR. YODER: You do have silica going into

4 the water, and you're counting on your reactor water

5 cleanup system to take that out. As far as impact on

6 the actual fuel itself, but we're not aware of any impact

7 on the fuel.

8 CHAIRMAN SKILLMAN: I was just wondering

9 if there's any relationship between dissolution of

10 Boraflex and some of the fuel problems that you're

11 having for which you put in that great big filter.

12 MR. YODER: I would say no.

13 CHAIRMAN SKILLMAN: I would say no too,

14 but I just wanted to ask the question. Thank you.

15 Thank you.

16 MR. SAYOC: Okay, next slide. The final

17 item we want to highlight pertains to the emergency

18 diesel generator crankcase vent lines. This was an

19 item that was brought to the attention to the NRC staff

20 by the ACRS to review the conclusion that the vent lines

21 are not subject to aging management review. The staff

22 appreciates ACRS for giving this feedback.

23 In RAI 2.3.3.16-1, the staff noted that

24 the Division I and II Emergency Diesel Generator vent

25 lines as delineated in the Drawing LRA-PID-08-9B were

1 not depicted as being subject to AMR. The staff
2 question how the function of the venting crankcase where
3 the Division I and II Emergency Diesel Generators and
4 the HPCS diesel generator will be maintained during
5 the period of extended plant operations.
6 Entergy responded, in part, the function
7 of venting the crankcase is not necessary for the diesel
8 to operate under emergency conditions. This is shown
9 in the USAR Section 8311.4.1 which lists two sets of
10 conditions under which the diesel will trip, one set
11 for both normal and emergency conditions and one set
12 for normal conditions only.
13 The trip for high crankcase pressure is
14 only listed with a set for normal conditions and not
15 as a required trip for emergency conditions. In fact,
16 the non-emergency trips are bypassed on receipt of
17 emergency start signal.
18 Upon revisiting this issue and preparing
19 for this ACRS subcommittee meeting, the staff
20 determined that further clarification of the technical
21 content of the applicant's RAI is warranted. To
22 facilitate this clarification, the staff relayed this
23 issue to the applicant such that they would prepare
24 for a discussion here today.
25 Specifically, the staff finds that the

1 applicant needs to either justify to the NRC why the
2 EDG vent pipes do not have either a 54.4(a)(1) or (a)(2)
3 function. Or if they serve either a 54.4(a)(1) or
4 (a)(2) function, then the applicant needs to propose
5 an aging management program and AMR line items to age
6 manage the vent pipes.
7 As you heard today, Entergy plans to
8 supplement it's RAI response regarding this issue in
9 the upcoming weeks. The staff will review the
10 applicant's supplemental information for completeness.
11 Subsequently, the staff plans to amend the River Bend
12 license renewal safety evaluation report before ACRS
13 full committee meeting on November 1. Next slide.
14 MR. SCHULTZ: Your last comment answered
15 a question I was going to ask. In going through the
16 SER, there are many instances where the staff has
17 documented an additional commitment that was made by
18 Entergy as a part of the interactions that have gone
19 back and forth, especially through the responses to
20 the RAI. So the completion of that documentation is
21 going to be accomplished just in the next few weeks?
22 MR. SAYOC: Well, certainly for the case
23 of the crankcase, we'll --
24 MR. SCHULTZ: This one? Oh, okay.
25 MR. SAYOC: We will look through the SER

1 and see if there's any other items that we need to
2 complete as far as documentation. And we'll update
3 the SER prior to November 1, our full committee.
4 MR. SCHULTZ: November 1, okay. I noted
5 the -- I mean, the example I was looking at was this
6 stainless steel underground piping and a commitment
7 to increase the frequency of the inspection above and
8 beyond what was in the original proposal. It'd be two
9 inspections in ten years instead of one. Those things
10 are already documented?
11 MR. SAYOC: Do we have --
12 MR. DONOGHUE: This is Joe Donoghue. If
13 there's a commitment that the applicant made and we
14 relied upon it in our review, my expectation is that
15 they made it in the commitment list. Garry is to the
16 mic.
17 MR. YOUNG: Yes, this is Garry Young with
18 Entergy. The commitments and the changes to the
19 commitments that result from the RAI interaction that's
20 documented in the SER have all been captured.
21 And so when we talked about our commitment
22 management system, that includes the original
23 commitments and then all of the modifications to those
24 commitments. And then when the SER is finally
25 published in the final form, we will go back and verify

1 that we have correctly captured the changes to the
2 commitments that have occurred as documented in the
3 SER in our system that we have in the plant.
4 MR. SCHULTZ: Okay. So then it's
5 iterative and well understood who's doing what then?
6 MR. YOUNG: It's iterative and we have what
7 we call a living LRA where we capture all of this
8 information at the plant. And then by the time the
9 SER is published, we believe we have a completely
10 accurate picture. But we will verify it against the
11 results that are documented in the SER.
12 MR. SCHULTZ: Excellent. Go ahead.
13 MR. HISER: This is Allen Hiser of the
14 staff. And within the SER whenever there is a
15 commitment, there should be a commitment number
16 associated with it so it ties directly. If there is
17 not a number associated with it, then we need to go
18 back and make sure that it is on the list.
19 MR. SCHULTZ: Okay, good. Thank you.
20 MR. OESTERLE: This is Eric Oesterle from
21 the staff. Just another piece of the puzzle. When
22 we get ready to issue a renewed license, what we always
23 do is include a license condition which enforces rolling
24 all those commitments that we've relied on in the SER
25 into the plant's licensing basis the day that we issue

1 the renewed license. So it gets incorporated that day
2 into the UFSAR.
3 MR. SCHULTZ: Thank you.
4 MR. SAYOC: Okay. On the base of its
5 review, the staff determines that the requirements of
6 10 CFR 54.29(a) have been met for the license renewal
7 of River Bend Station, Unit 1. This concludes my
8 presentation now. If there are any questions, the
9 staff would like to take them at this time.
10 CHAIRMAN SKILLMAN: So colleagues around
11 the table, are there any further questions for the NRC
12 staff on the matter of River Bend license renewal?
13 MEMBER RICCARDELLA: I believe somebody
14 from the staff was going to brief us on the core shroud
15 cracking and how that is going to be monitored into
16 the period of extended operation.
17 MR. MEDOFF: So this is Jim Medoff of the
18 staff. I was responsible for the vessel internals
19 program review. Entergy -- as has been explained to
20 you before, this is a new process. So we didn't put
21 quite as much information in the SER. But a lot of
22 the things we did review are included in the audit
23 report.
24 We did look at the operating experience
25 for the core shroud as explained in several condition

1 reports. And we did confirm it was an unrepaired shroud
2 and we were able to confirm that they assessed the extent
3 of cracking including taking into account some
4 proximity rules if cracks were close to one another.
5 What we didn't have from Entergy at the start was
6 whether they had re-categorized the shroud.
7 What we did was we asked them an RAI on
8 that and Todd Sherman, my counterpart at the utility,
9 explained that they did re-categorize the shroud and
10 they did put it in an RAI response. So that's
11 documented in the operating experience of the AMP
12 write-up for the VIP or vessel internals program. It's
13 in Section 3.0. And also, we have a write-up in the
14 audit report.
15 MEMBER BALLINGER: So let me ask the
16 question about the re-categorization. It's usually
17 re-categorized based on dose or fluence or
18 conductivity.
19 MR. MEDOFF: From what I can tell from my
20 reading of VIP 76-8 documents, re-categorization based
21 on flaw size reinspection.
22 MEMBER BALLINGER: Okay, flaw size.
23 Okay, all right. Because it's A, B, and C.
24 CHAIRMAN SKILLMAN: Colleagues, any other
25 questions for the staff before we release them?

1 Hearing none, Manny, thank you very much.
2 MR. SAYOC: Thank you, sir.
3 CHAIRMAN SKILLMAN: At this point in the
4 meeting, I would like to ask if there are any individuals
5 in the room that would like to make a comment relative
6 to the license renewal activity for River Bend nuclear
7 station. Seeing none, if the phone line is open, if
8 someone is out there, would you please simply say hello.
9 PARTICIPANT: Hello.
10 CHAIRMAN SKILLMAN: Thank you. Now, if
11 anybody on the phone line would like to make a comment,
12 I invite you to do so at this time. Please introduce
13 yourself. Hearing none, Kent, please close the line.
14 Colleagues, any final comments for either
15 the NRC staff or the Entergy staff? Hearing none, Manny
16 and to your team, thank you for a very thorough
17 examination of River Bend. And to John Ventosa and
18 his crew from Entergy, thank you for bringing your team
19 all this distance and for the presentations that you
20 have presented to us today.
21 So to the staff and to Entergy, thank you.
22 And with that, we are adjourned.
23 (Whereupon, the above-entitled matter went
24 off the record at 3:15 p.m.)
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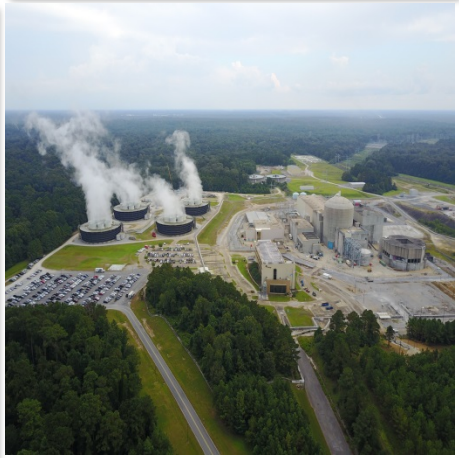
River Bend Station License Renewal



Entergy Presenters

Name	Title
John Ventosa	Chief Operating Officer-South
James Henderson	Director, Engineering
Tim Schenk	Manager, Regulatory Assurance
Garry Young	Director, Fleet License Renewal

Agenda

- Background
  - Site Description
  - Plant Status
  - Licensing History
  - Major Equipment Upgrades
- License Renewal Project
  - License Renewal Application (LRA)
  - Aging Management Programs and Commitments
- Conclusion

RBS Site Description

- Located in West Feliciana Parish, Louisiana, approximately 24 miles north-northwest of Baton Rouge, Louisiana
- General Electric NSSS – Stone & Webster (constructor)
- BWR-6, GE Mark III containment
- GE turbine generator

RBS Site Description

- Ultimate heat sink is independent wet cooling tower
- Closed circulating water system with mechanical draft cooling towers
- Licensed thermal power - 3091 MWt
- Staff complement - approximately 820

RBS Plant Status

- Plant Status
  - 100% power
  - 24-month cycle
  - ROP action matrix Column 1
- Last Refueling Outage
  - RF19 (Spring 2017)
- Next Refueling Outage
  - RF20 (Spring 2019)

RBS Licensing History

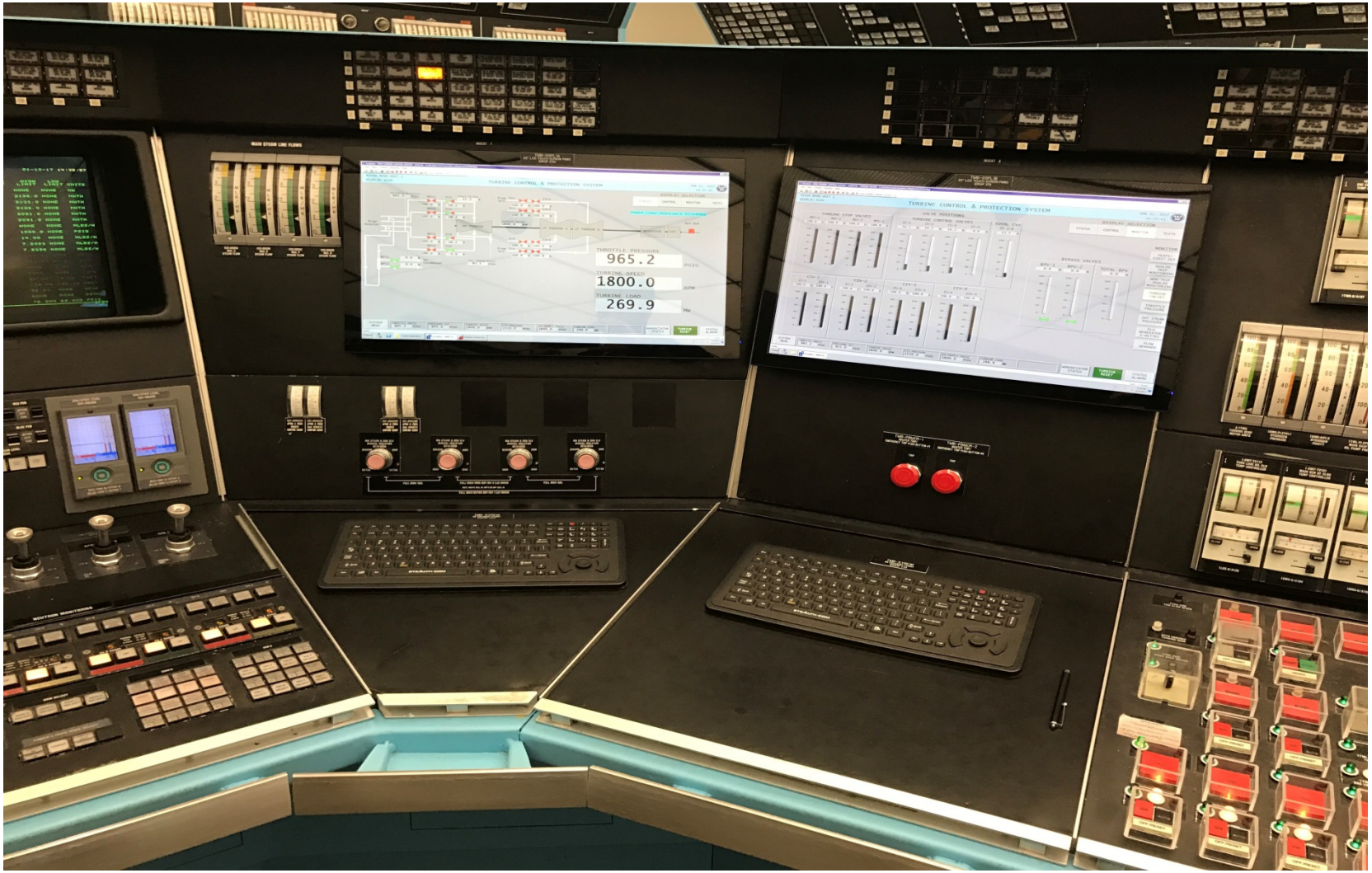
Construction Permit	March 25, 1977
Operating License	November 20, 1985
Commercial Operation	June 16, 1986
5% Power Uprate	November 2000
Power Uprate License Amendment (1.7% Thermal Power Optimization)	January 31, 2003
LRA Submitted	May 25, 2017
Operating License Expiration	August 29, 2025

Major Equipment Upgrades

Completed

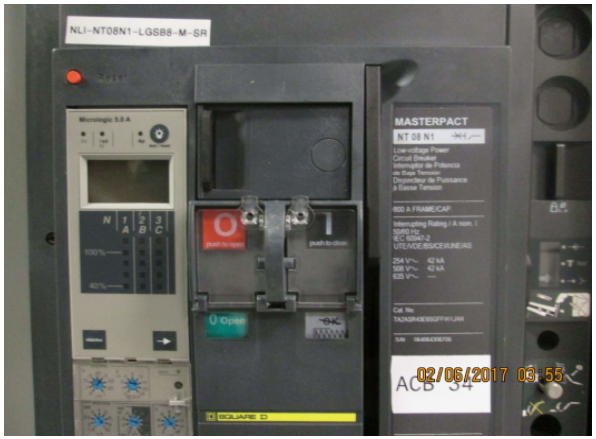
- Upgraded digital EHC turbine controls
- Upgraded control building chiller controls
- Recoated underground circulating water piping
- Replaced inverters
- Replaced carbon steel piping
- Upgraded normal service water cooling tower
- Replaced 4th point feedwater heaters
- Upgraded 480 V load center breakers

Photos – Digital EHC



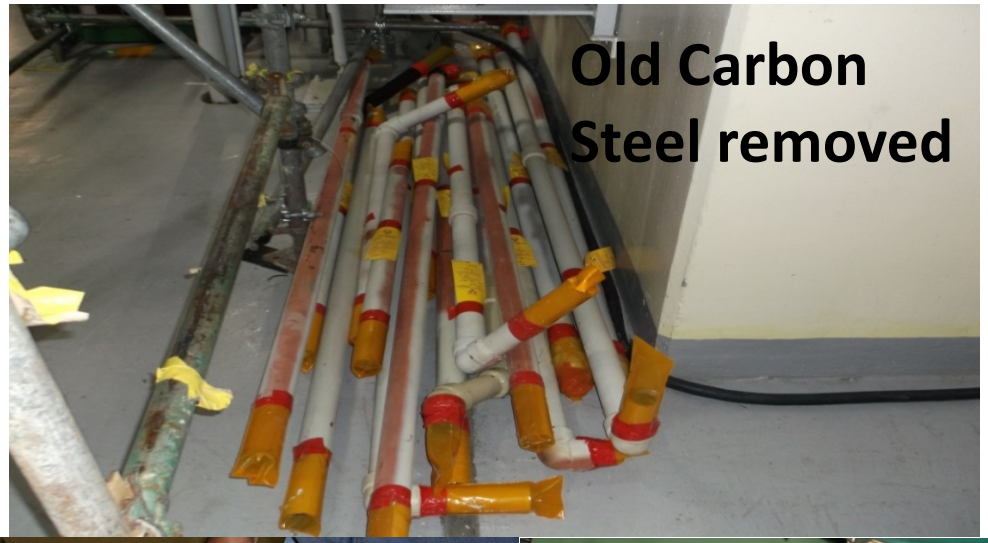
Human Machine Interface for EHC on the H13-P680 Panel

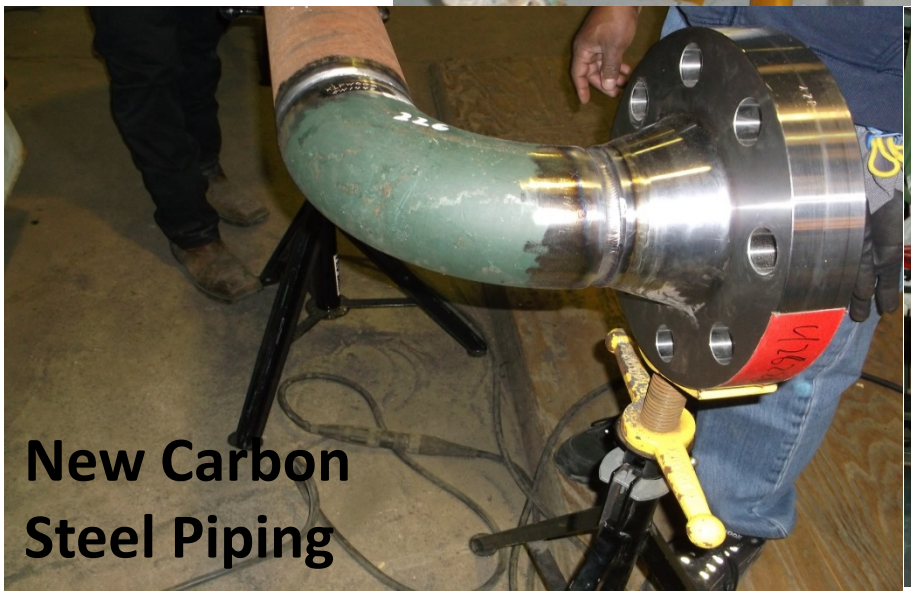
Photos – 480 V Loadcenter Breakers

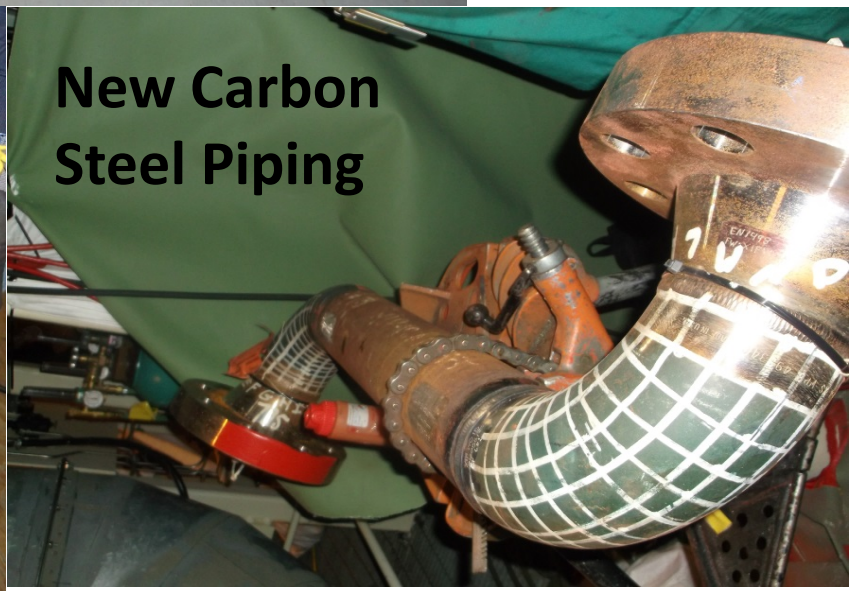


Photos – Carbon Steel Piping Replacement

Carbon Steel Piping Replacement in RF-18 and RF-19







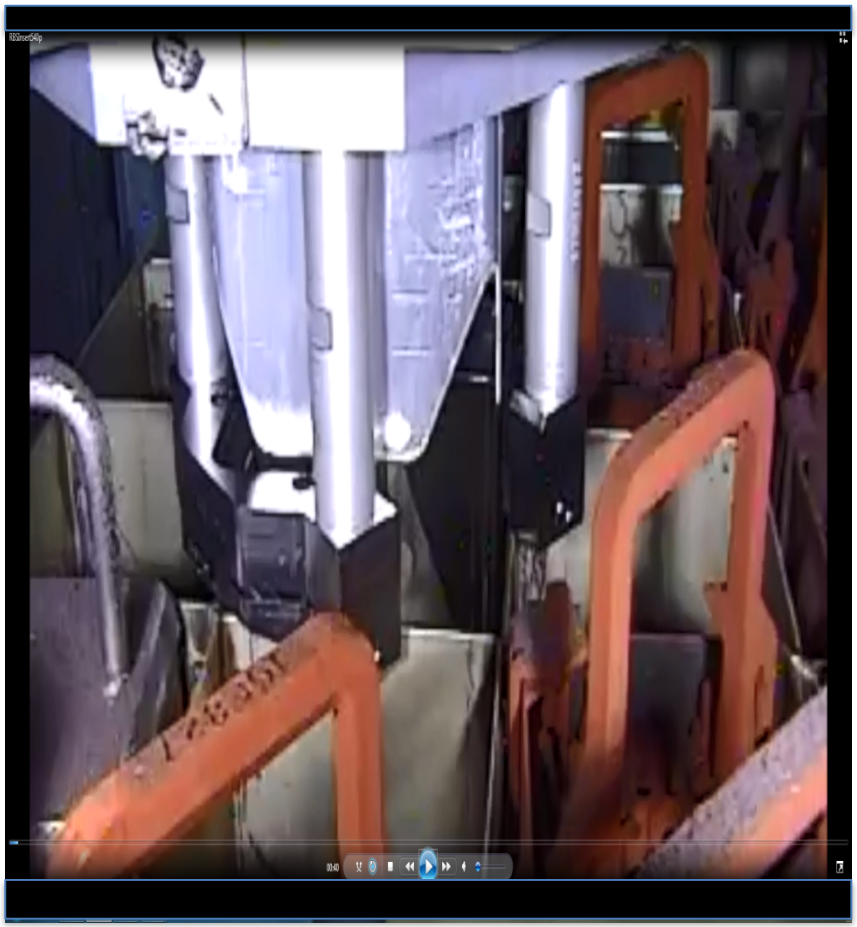
Major Equipment Upgrades

Planned

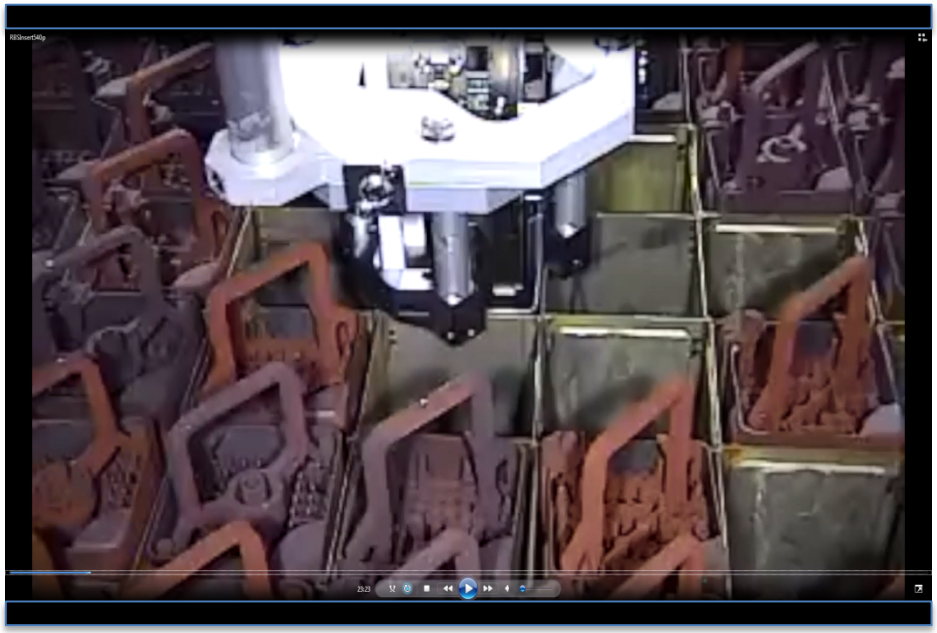
- Turbine building chiller replacements
- Spent fuel pool neutron absorber upgrade
- Condenser upgrades
- Service water cooling heat exchanger refurbishment
- Fancy Point switchyard upgrades
- Recirculation pump power cable replacement
- Feedwater strainer
- Feedwater level control

Photos – Neutron Absorber Prototype Inserts

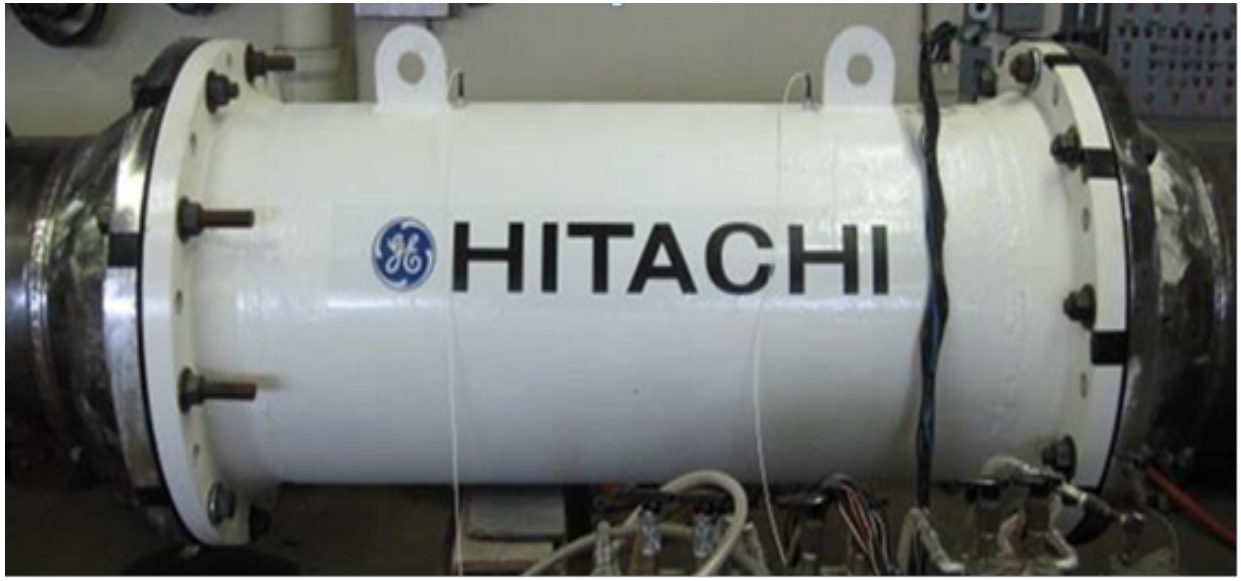
Start of absorber insertion



Full insertion. Ready to retract tool



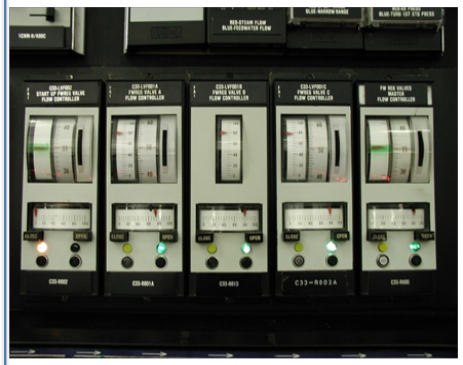
Photos – Feedwater Strainer



Photos – Feedwater Level Controls

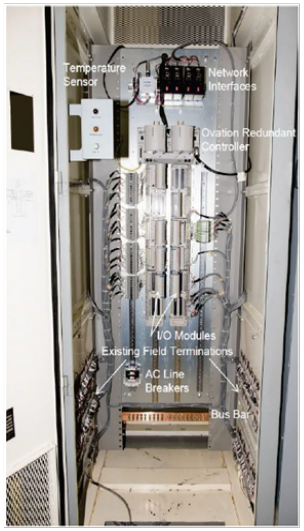
Past

- RBS has had multiple issues with the FWLC system in the past contributing to reactor SCRAMS
- System is currently the GE original analog control system with reverse engineered Baily control cards.



Present

- SIPD 3166 has been presented to upgrade the FWLC system to DCS control system, such as Ovation.
- This Mod is proposed to be installed RF21



Future

- Will increase the reliability of the feedwater system, leading to few SCRAMS or down-powers.
- Automatic Feedwater control over the complete range of normal power operation (1 – 100 percent) and optionally during plant heat up/cooldown
- Ability and spare capacity to expand and upgrade plant controls to the ovation platform as needed.
- Long Term Benefits:
  - Improves Reliability
  - Increases Defense in Depth
  - Addresses Obsolescence and spares issues
  - Eliminates several Single Point Vulnerabilities
  - Improves Data Collection

RBS License Renewal Project

- Experienced, multi-discipline Entergy team (corporate and site personnel) prepared the license renewal application (LRA)
- Incorporated lessons learned from previous applications
- Used NEI 95-10 guidance
  - Scoping and screening process
  - Aging management review
  - LRA format and content
- Used Revision 2 of NUREG-1801
- 18-month NRC review schedule

Safety Evaluation Report

- SER issued August 2018
  - No open items
  - No confirmatory items

Aging Management Programs and Regulatory Commitments

- **43 Aging Management Programs**
  - 12 new programs
    - 12 consistent without exception
  - 30 existing programs
    - 10 consistent without exception
    - 13 consistent with enhancements
    - 2 consistent with exceptions
    - 5 consistent with exceptions and enhancements
  - 1 existing plant-specific program with enhancements

Program Commitment Implementation

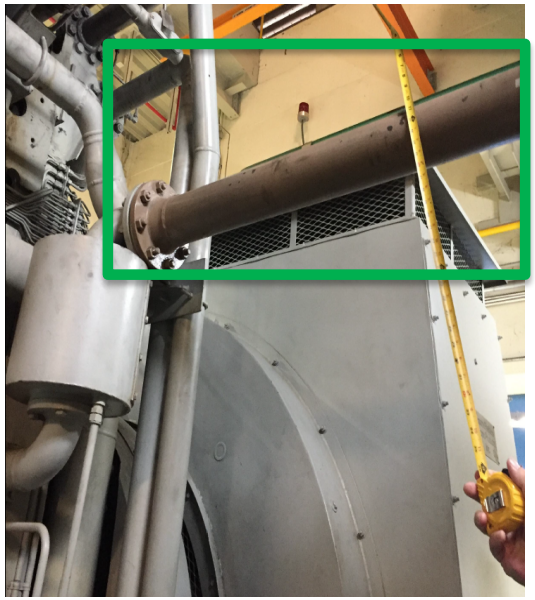
- Regulatory commitments in the commitment management system track enhancements to existing programs and implementation of new programs
- Entergy has significant experience with license renewal commitment implementation
- Similar new AMPs and AMP enhancements have been successfully implemented at other Entergy plants

Conclusion

- Entergy is committed to the long-term operation and continuous improvement of our facilities.
- Entergy will manage the effects of aging in accordance with 10 CFR 54.21(a)(1)
- Entergy has evaluated time-limited aging analyses that require evaluation under 10 CFR 54.21(c)
- Entergy has met provisions of 10 CFR 54 for issuance of a renewed license.

Standby Diesel Crankcase Vent

- RAI response 2.3.3.16-1 & SER page 2-50
- ACRS raised question on wording of RAI response
- Agree wording is misleading – RAI supplement planned to clarify
- Aging effects would not prevent venting



United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards License Renewal Subcommittee

River Bend Nuclear Generating Station Safety Evaluation Report (SER)

September 20, 2018

Emmanuel Sayoc, Project Manager
Office of Nuclear Reactor Regulation

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Presentation Outline

- Overview of River Bend Station (RBS) License Renewal Review
- Region IV 71002 Inspection: License Renewal Inspection
- SER Section 2: Scoping and Screening Review
- SER Section 3: Aging Management Review
- SER Section 4: Time-Limited Aging Analyses
- Conclusion

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License Renewal Review: Audits and Inspections

Audit / Inspection	Dates	Location
Operating Experience Audit	October 2 – 13, 2017	Rockville
Scoping & Screening Methodology Audit	October 24 – 26, 2017	Onsite
Aging Management Program (AMP) Audits	October 16 – November 8, 2017 November 6 – 10, 2017	NRC HQ Onsite
Region IV 71002 Inspection: Scoping, Screening, and AMPs	February 26 – March 2, 2018 March 19 – 23, 2018	Onsite

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SER Overview

- Final SER issued August 16, 2018
  - No open items or confirmatory items
  - Total of 119 RAIs issued
    - 15 follow-up RAIs

71002 Inspection: Scope

- Scope:
  - Scoping and screening of components
  - Walk down of accessible areas
  - Review of 25 AMPs
    (6 new & 19 existing)

- Team of 4 conducted on-site inspection for 2 weeks:
  - Weeks of February 26 and March 19, 2018

- Inspection Report issued May 7, 2018 (ML18127B169)

71002 Inspection: Results

- Facility was in good material condition
- Applicant agreed to include existing periodic heat exchanger inspections for their service water systems into their plant-specific Periodic Surveillance and Preventive Maintenance aging management program

71002 Inspection: Conclusions

- Scoping and screening performed in accordance with 10 CFR 54
- Information easily retrievable and auditable
- Existing programs effectively managed aging effects
- Reasonable assurance that aging effects will be managed and intended functions maintained

SER Section 2

- **Structures and Components Subject to Aging Management Review**
  - Section 2.1: Scoping and Screening Methodology
  - Section 2.2: Plant-Level Scoping Results
  - Sections 2.3, 2.4, 2.5: Scoping and Screening Results

SER Section 3

- **Aging Management Review Results**
  - Section 3.1: Aging Management of Reactor Vessel, Internals, and Reactor Coolant System
  - Section 3.2: Aging Management of Engineered Safety Features
  - Section 3.3: Aging Management of Auxiliary Systems
  - Section 3.4: Aging Management of Steam and Power Conversion Systems
  - Section 3.5: Aging Management of Containments, Structures and Component Supports
  - Section 3.6: Aging Management of Electrical Commodity Group

SER Section 3

Section 3.0.3 - Aging Management Programs

Applicant's Disposition of AMPs	Final Disposition of AMPs in SER
• 11 new programs – All consistent	• 12 new programs – All consistent
• 31 existing programs – 12 consistent – 13 consistent with enhancements – 2 consistent with exceptions – 4 consistent with enhancements and exceptions	• 30 existing programs – 10 consistent – 13 consistent with enhancements – 2 consistent with exceptions – 5 consistent with enhancements and exceptions
• 1 plant-specific existing program	• 1 plant-specific existing program

SER Section 4

- **Time-Limited Aging Analyses (TLAAs)**
  - 4.1: Identification of TLAAs
  - 4.2: Reactor Vessel Neutron Embrittlement Analyses
  - 4.3: Metal Fatigue Analyses
  - 4.4: Environmental Qualification of Electric Equipment
  - 4.5: Concrete Containment Tendon Prestress Analyses
  - 4.6: Containment Liner Plate, Metal Containment, and Penetrations Fatigue Analyses
  - 4.7: Other Plant-Specific TLAAs

Reactor Vessel Neutron Fluence

- Issue:
  - No basis for the adequacy of the neutron fluence methodology for RPV beltline components above the active fuel region
- Resolution:
  - Fluence methodology includes sufficient conservatisms:
    - Accounting for potential uncertainties in the above-core water densities
    - Considering the bounding power/flow statepoint that leads to higher fluence
  - 60-year fluence calculations are conservative and meet RG 1.190
  - TLAA demonstrated to be acceptable per 10 CFR 54.21(c)(1)(ii)

High Voltage (HV) Insulators: Use of Polymeric Material

- Issue:
  - HV insulators made of polymeric material identified during on-site audit, while LRA only cited porcelain insulators
  - GALL has not evaluated polymeric HV insulators

- RAI requested:
  - Justification for not listing polymeric material in LRA
  - Discussion of site-specific aging mechanisms, aging effects, and chemical contaminants from animal excrement associated with polymeric HV insulators

- Applicant's RAI Responses:
  - Revised LRA to include polymeric HV insulators
  - Addressed pertinent aging effects and mechanisms
  - Proposed periodic preventive maintenance and inspections

- Staff's Conclusion:
  - Changes in LRA to include polymeric HV insulators, periodic preventive maintenance and inspections are acceptable

Neutron Absorbing Material Monitoring Program

- New program consistent with GALL Report AMP XI.M40
- Will adequately manage the effects of aging
- Replacement for Boraflex monitoring program that was previously credited for neutron absorbing material
  - Due to degradation, Boraflex material currently in the spent fuel pool will not be able to maintain required sub-criticality margin into period of extended operation (PEO)
  - Plans to submit LAR for SNAP-IN® inserts end of 3rd quarter 2018
  - Installation scheduled for June – October 2019
  - Aluminum boron-carbide neutron absorbing material will be installed prior to PEO

RAI 2.3.3.16-1: EDG Crankcase Vent Lines Not Subject to AMR

- Issue:
  - ACRS identified concern re: RAI response regarding the Division I & II Emergency Diesel Generator vent lines being not necessary for the diesels to operated under emergency conditions.
  - Information provided does not clearly provide technical justification as to why the vent lines do not have either 54.4(a)(1) or (a)(2) function.

- Resolution:
  - Staff contacted RBS to make them aware of the ACRS concern.
  - RBS plans to supplement this information by October 15, 2018.
  - Staff will review the supplemented information and revise the SER accordingly.

Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of River Bend Station, Unit 1.

Backup Slides

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HV Insulators: Loss of Material Due to Mechanical Wear

- Issue:
  - EPRI 1003057 states that mechanical wear in porcelain HV insulators is an aging effect
  - GALL report recommends plant-specific AMP for loss of material due to mechanical wear & reduced insulation resistance
  - Polymeric HV insulators have not been addressed in the LRA
- RAI requested:
  - Include evaluation of metallic material used and applicable loss of material in polymeric HV insulators
- Applicant's Response:
  - Metallic components of polymeric HV insulators are similar to porcelain type previously evaluated in the LRA
  - Loss of material due to mechanical wear is not an applicable aging effect (same as porcelain insulators)
  - No plant-specific AMP is required
- Staff's Conclusion:
  - Applicant's evaluation is consistent with license renewal Standard Review Plan and acceptable

Here are my comments regarding the River Bend Nuclear Generating Station, Unit 1 License Renewal Application.

The ACRS Subcommittee on Plant License Renewal is asked consider the following comment with respect to the aging management program for systems, structures, and components that are credited for the renewal of River Bend's operating license:

According to River Bend's FSAR (Chapter 15.0.3, ADAMS No. ML17226A118), "infrequent incidents" are described as incidents that, "may occur during the life of the particular plant (spanning once in 20 yr to once in 100 yr)." These events are also known as "abnormal (unexpected) operational transients." Therefore, the River Bend nuclear generating plant must be designed to deal with as many as two infrequent incidents during its design lifetime of 40 years, without endangering the public health and safety.

Infrequent incidents are not like anticipated operational occurrences, which might occur one or more times during a calendar year of operation, and which are remedied simply by a reactor shutdown. A single infrequent incident that does not receive the correct response, from the plant's automatic reactor protection systems, or from its operators, could easily end the plant's operating lifetime (e.g., consider the consequences of the unmitigated infrequent incident that occurred at Three Mile Island, in 1979).

If River Bend's operating license is renewed, then the plant must be designed to deal with as many as three infrequent incidents during its new design lifetime of 60 years, without endangering the public health and safety.

Probabilistic risk assessment (PRA) arguments could well dismiss the occurrence of three infrequent incidents, as highly unlikely; but the use of PRA would be inappropriate in this application. This is because 10 CFR §54 requires that plants maintain their current, deterministic licensing bases during the extended terms of operation that are authorized by their renewed licenses. Consider that an even less likely class of events, anticipated transients without scram (ATWS) is specifically listed in the scope of 10 CFR §54. The definition of scope, as defined in 10 CFR §54.4, includes, "(a) Plant systems, structures, and components within the scope of this part are … (3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for …. Anticipated transients without scram (10 CFR 50.62)." ATWS events are not likely to occur, and not included in plant design bases.

This is supported by the Statement of Consideration, "The Commission reaffirms its previous conclusion (see 56 FR 64943 - 64956) that PRA techniques are most valuable when they focus the traditional, deterministic-based regulations and support the defense-in depth philosophy. In this regard, PRA methods and techniques would focus regulations and programs on those items most important to safety

by eliminating unnecessary conservatism or by supporting additional regulatory requirements. PRA insights would be used to more clearly define a proper safety focus, which may be narrower or may be broader. In any case, PRA will not be used to justify poor performance in aging management or to reduce regulatory or programmatic requirements to the extent that the implementation of the regulation or program is no longer adequate to credit for monitoring or identifying the effects of aging." --- FR 22468, Vol. 60, No. 88 (May 8, 1995)

River Bend's aging management program should account for the potential increase in infrequent incidents that would accompany the extension in operating lifetime. That is, increasing the plant's operating lifetime by 50% will consequently increase the number of potential infrequent incidents by 50%. (This issue also applies to other BWRs, and to PWRs, as well.) Since increasing the authorized operating lifetime of a plant could increase the maximum number of infrequent incidents, from 2 to 3, then it seems that some sort of modification (e.g., in plant design or operation) would be required in order to maintain the number of infrequent incidents, in the CLB, at not more than 2 incidents over a period of 60 years of operation.

10 CFR §54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*, "governs the issuance of renewed operating licenses for nuclear power plants." So, is the renewal of an operating license the same as the issuance of a renewed operating license? If yes, then why is 10 CFR §54 required? Would it not be simpler, and less confusing, to issue a license amendment, under 10 CFR §50, which would extend the license expiration date, and record a license commitment (or condition) to establish and implement an acceptable aging management program? Then the new expiration date would be specified in a license amendment that converts a 40-year license into a 60-year license. Approval of the license renewal, as an amendment, would also be subject to the requirements of 10 CFR §50.92, *Issuance of amendment,* which addresses, among other things, the question of whether the operation of the facility, in accordance with the proposed amendment, would cause a significant increase (e.g., 50%) in the probability of an accident (e.g., an infrequent incident) previously evaluated. In this way, (1) the CLB is maintained, (2) there is no doubt as to whether all amendments and commitments that were made for a 40-year license also apply to a 60-year license, and (3) the license renewal is accomplished by amendment to an existing license, consistent with all other major changes (e.g. power upratings); not by issuing a "renewed license".