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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of:

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

305th General Meeting

Docket No.

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1 UNITED STATES OF AMERICA
2 NUCLEAR REGULATORY COMMISSION

3
4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

5
6 305th GENERAL MEETING

7
8 Room 1046

9 1717 H Street, N. W.

10 Washington, D. C.

11 Thursday, 12 September 1985

12
13 The Advisory Committee on Reactor Safeguards was
14 convened at 8:40 a.m., David Ward, Chairman of the Committee,
15 presiding.

16 PRESENT FOR THE ACRS COMMITTEE:

17 D. Ward, Chairman

18 H. Lewis

19 J. Ebersole

20 D. Moeller

21 D. Okrent

22 C. Michelson

23 G. Reed

24 C. Wylie

25 F. Remick

1 PRESENT FOR THE ACRS COMMITTEE; (Continued)

2 P. Shewmon

3 J. C. Mark

4 C. Siess

5 R. Axtmann

6 W. Kerr

7 PRESENT FOR NRC STAFF:

8 R. Blau

9 G. Gears

10 W. Hazleton

11 D. Scaletti

12 J. Rosenthal

13 M. Rubin

14 J. Read

15 A. Serkiz

16 K. Kniel

17 R. Bosnak

18 J. O'Brien

19 PRESENT FOR GE:

20 R. Villa

21 G. Sherwood

22 D. Hankins

23 K. Holtzelaw

24 PRESENT FOR BNL:

25 C. Shu

P R O C E E D I N G S

MR. WARD: We will now hear from Mr. Ebersole.

MR. EBERSOLE: I will comment on each of the things of particular interest to the committee. The first one is inadvertent actuation of the fire suppression system at Hope Creek. You may recall I called out in TVA again that there had been rooms overpressurized and doors blown off by malfunctions of the delivery system from the large storage systems for CO₂, and certainly an implied threat to blow apart safety rooms such as battery rooms or others that might be protected and had a strong enclosure including the doors.

Thus, apparently what should be a relatively hazard-free system may have some substantial hazard potential if it is maloperated by inappropriate operative devices or not provided relief panels or whatever to get rid of mistakes in the control system.

I'm going to turn all this over to Ernie Taylor for Item No. 1, the Hope Creek inadvertent actuation of the fire suppression system.

MR. ROSSI: I'm Ernie Rossi, Chief of the Events Analysis Branch in the Office of Inspection and Enforcement.

We have five events on which formal presentations will be given this morning. These will be discussed by various members of the Office of Inspection and Enforcement and the Office of Nuclear Reactor Regulation. I will

1 introduce them as they make their presentations.

2 In addition to the five presentations, we have with
3 us Nick Chrissotimos from Region III, who at the end of the
4 five presentations is going to say a few words about FERMI 2
5 premature criticality which occurred on July 2nd of this
6 year. We understand there were a couple members of the
7 committee who were interested in hearing something about that
8 event today.

9 Also, to help us in answering questions which you
10 might have, we have a number of other people with us. Among
11 these are Alex Dromery from the Office of Inspection and
12 Enforcement. We have Ron HERNON, Dave Wagner, Dan McDaniel
13 and Warren Hazelton from the Office of Nuclear Reactor
14 Regulations, and I believe we were going to have one person
15 from Region I here.

16 MR. BLAU: My name is Randy Blau from Region I,
17 Senior Resident Inspector, Hope Creek.

18 MR. ROSSI: Fine. So we will begin with the
19 presentation on the Hope Creek inadvertent actuation of the
20 fire suppression system, and that will be given by Jim
21 Henderson of the Office of Inspection and Enforcement.

22 We also have Jack Strosnider who joined us from the
23 region to help answer questions on Hope Creek.

24 [Slide.]

25 MR. HENDERSON: I don't know whether this

1 transparency will be of any help, but it will give you some
2 outline of the situation while I talk.

3 I'm Jim Henderson of the Inspection and Enforcement
4 Engineering and Generic Communications Branch.

5 When we met with the subcommittee on Tuesday, some
6 concerns were expressed and questions asked that we couldn't
7 answer, although I tried. In my presentation I will try and
8 answer them, and to the extent I can't, I have some backup
9 from the region. The resident inspector will be able to help
10 on things like building arrangement and things of that nature
11 since I have not been to the site.

12 Hope Creek is a one-unit BWR site contiguous to the
13 Salem site. It is in the last stages of construction, and on
14 the 4th of September at just the day before we received the
15 first shipment of fuel, various elements of the plant are not
16 yet fully complete. For example, there is still temporary
17 construction access openings in compartment boundaries, an
18 ventilation systems are not fully operational.

19 On the morning of September 4th, a walk-through
20 emergency site drill related to the receipt of fuel was in
21 progress. Construction personnel had been notified and they
22 were not involved. At about 8:45 a.m. there was an automatic
23 initiation of CO2 fire suppressant to a diesel fuel oil tank
24 room. The CO2 injection continued beyond the design time and
25 quantity limits.

1 There was no apparent damage to any structure,
2 systems or components, but adjacent workmen were affected.
3 Evacuation was promptly initiated. It was somewhat slowed
4 down by the precognizance of the drill in progress and the
5 assumption that the evacuation was not real but part of the
6 drill.

7 The building was evacuated and 23 individuals were
8 transported to hospitals. We have no real information on
9 their present state. It seems they got behind the cloak of
10 medical confidentiality and nobody is talking about it.
11 Incidentally, this thing does come under the purview of OSHA
12 as an industrial accident rather than under NRC as a nuclear
13 event.

14 There are four diesel fuel oil tank rooms in line
15 with corridors on each side of the row, and cross access at
16 the ends. The four deisel generators sit each on top of the
17 associated tank room. Each tank room is about 30 feet high,
18 with single access door, with the door sill about 20 feet
19 above the tank room and adjacent corridor floor accesses by
20 ladder to a platform outside the normally closed door and
21 grating inside the door.

22 Each door contains louvers which allow escape of air
23 displaced by incoming CO2 and prevent overpressurization of
24 the compartment by excessive CO2 injection such as was
25 experienced during this event.

1 When the CO2 injection occurred, the injection was
2 intended to be automatically terminated on a time delay of
3 about 72 seconds with release of between one and two tons.
4 Current information indicates that when the control system
5 timed out and reset, it promptly reinitiated, and this
6 sequence occurred until the entire contents of the CO2 storage
7 tank, which at that time was 10 tons in the 17-ton capacity
8 tank, had been discharged.

9 The Licensee believes that the problem is maybe in
10 the system control panel, and the panel has been removed and
11 sent to the manufacturer, Cardox, for evaluation.

12 The subcommittee asked what peak pressure was reached
13 in the tank room. There is no installed pressure sensing and
14 recording equipment for the tank room, so the answer can only
15 be qualitative. CO2 is normally stored as a liquid at modest
16 temperatures and pressures. When released, it promptly starts
17 to vaporize. But the latent vaporization is applied by
18 subcooling to the point where it freezes. Subsequent
19 sublimation as heat is absorbed from the environs, is
20 relatively slow, and apparently the escape area of the door
21 louvres was sufficient to prevent appreciable pressure buildup
22 in this plant design.

23 MR. BLAU: Excuse me, Jim. My name is Randy Blau.
24 I'm Senior Resident Inspector at Hope Creek. I have some
25 additional information that I got late yesterday.

1 The Applicant did an injection test in the room
2 this spring and they did measure the pressure. From the
3 pressure they got from a normal injection, they did
4 calculations that had not been reviewed but showed that --
5 their calculations show that with the existing configuration,
6 a full tank dump in the room should have resulted in about
7 .6 pound of pressure in the room.

8 Now, the room is not in its final operations phase
9 configuration in that the area around the doors, around the
10 door frame has not been sealed and will be sealed at a later
11 date. At that point, the only event path will be under the
12 door and a design opening around ventilation intake, which
13 closes automatically on CO2 but has a ventilation that has a
14 vent path around it.

15 The previous information that there was a louvre in
16 the door is not correct. In the operations phase, the
17 pressure from a full tank dump into the room would be worse
18 than the .6 calculated, and the Applicant has further
19 calculations necessary to make sure that the
20 overpressurization does not exceed NFPA requirements.

21 MR. HENDERSON: Thank you, Randy. That's a big
22 help.

23 An event similar to this event is reported to have
24 occurred at Grand Gulf on July 14, 1982. The protected volume
25 was the ECCS penetration room, and the room was tight enough

1 so that a locked door was forced open. At that time the cause
2 was believed to be an internal and intermittent fall in the
3 actuation circuitry between the sensor and the control panel,
4 not in the control panel.

5 The potential generic implications will be examined
6 after the evaluation of the Cardox efforts at Hope Creek.

7 So there is, at least one historic event that looks
8 quite similar to this, and there is a possibility that there
9 is a defect in the generic Cardox design. We will know about
10 that later.

11 I guess that is about all I have to say unless there
12 are questions.

13 MR. MOELLER: Several times the ACRS has written
14 letters asking particularly about the potentiality for CO2
15 getting into a control room, you know, due to a release, and
16 AEOD about, what, three or four years ago extensively looked
17 at this and wrote a report on it. So my question is, is this
18 something that is peculiar to the fact that they are in the
19 construction phase? Had they been operating, would the
20 sequence or the impact been different?

21 MR. HENDERSON: Randy, can you speak to that?

22 MR. BLAU: Yes. This event could happen in the
23 operations phase. The dispersal of their carbon dioxide would
24 not have been as great due to the fact that, for one, many
25 doors and construction cut-outs are still open in the plant

1 that would be closed and are, in fact, required to close
2 during operation. In this event CO2 got throughout the
3 54-foot elevation of the entire diesel area wing and the
4 adjacent radwaste building.

5 As I said, during operations, the extent of it would
6 not be quite as great due to the doors open and additionally
7 due to the ventilation system. The ventilation system at Hope
8 Creek has not yet been completed and, in fact, not balanced
9 yet, and during this event, the normal ventilation system was
10 not operating. So during operations, we would expect the event
11 to be different in CO2 dispersal.

12 I have not done a detailed review of the control
13 room ventilation system, but the design of the FSAR calls for
14 separate outside supply with redundant fan, safety related.
15 That provides a slight positive pressure in the control room
16 with passive exhaust atmosphere with safety-related dampers in
17 the exhaust.

18 MR. MOELLER: But you have the redundant intakes,
19 but does the control room have a CO2 monitor?

20 MR. BLAU: As far as I know, the control room does
21 not have a CO2 monitor.

22 MR. MOELLER: Which is another question, which is
23 off the subject, but does the control room have even a
24 radiation monitor?

25 MR. BLAU: The control room has radiation

1 monitors. Those have not been installed yet, but the
2 ventilation system shifts to a filtered ventilation system on
3 intake.

4 MR. MOELLER: It has monitors on the air intake, but
5 my question was, is there a radiation monitor within the
6 control room, meaning for external dose?

7 MR. BLAU: There is an area radiation monitor
8 measuring gamma dose rate in the control room, but there is
9 not an airborne monitor measuring, to my knowledge, the
10 quality of the air in the control room.

11 MR. MOELLER: Thank you.

12 MR. EBERSOLE: Are there any rooms which have
13 critical safety equipment which upon malfunction of the
14 distributing or apportioning systems would be mechanically
15 damaged, not provided with relief panels or what other means
16 that you have to do, to grant malfunctions and failures in
17 this apportioning system? Remembering, again, the
18 apportioning system is nonseismic and may do anything, in
19 fact, under the seismic system.

20 MR. BLAU: Right. The apportioning system is
21 nonseismic, nonsafety grade. It serves nine rooms, the four
22 diesel fuel base, the four diesel rooms, and a control
23 equipment mezzanine below the control room. The Applicant has
24 an engineering review that is going on. I'm sorry I can't
25 really answer your question. The Applicant now feels they can

1 prove that there won't be mechanical damage, but I can't
2 comment further on that.

3 MR. WYLIE: I just wanted to ask a question. I
4 understood you to say they had automatic louvres in the
5 pressurized room. They were closed on the ventilating system.

6 MR. BLAU: The ventilation system of all CO2 circ
7 rooms has CO2 fire dampers, which are combination fire dampers
8 which close on a heat signal, not a signal, melting of fusible
9 links. Also, when the CO2 activates, it sends an electrical
10 signal to the damper that fuses the link and allows the spring
11 to close the damper.

12 MR. WYLIE: That bottles up the room.

13 MR. BLAU: Those are fire protection dampers which
14 have a fire barrier rating. They are not air-tight dampers.
15 In other words, you would expect trace amounts of carbon
16 dioxide to escape through the dampers.

17 MR. WYLIE: Okay. Do they design for pressure
18 reliefs in the room?

19 MR. BLAU: These rooms do not have rupture discs or
20 other formal reliefs.

21 MR. WYLIE: A flapper is all you need someplace
22 high.

23 MR. BLAU: Right. The overpressure calculations
24 involve calculating the vent area, the available vent area. I
25 don't know if there is anyone here --

1 MR. WYLIE: I understood they would have gotten
2 .6 pound the way it is right now, but once sealed, you are
3 going to get much higher than that. If you assume one pound,
4 that is 144 pounds per square foot.

5 MR. HENDERSON: I think any more on this particular
6 area would be pure speculation.

7 MR. MICHELSON: I need clarification before you cut
8 off the subject. The other day you told us CO2 got into the
9 diesel room itself. I'm wondering if you can confirm --

10 MR. EBERSOLE: He said it is the diesel room.

11 MR. MICHELSON: It is the tank room.

12 MR. BLAU: It was the tank room below, which is in
13 the basement, at elevation 54.

14 MR. MICHELSON: The clarification I need, did any of
15 it get into the diesel room?

16 MR. BLAU: They did not detect any -- the safety
17 efforts involved people in air masks looking for unconscious
18 people. They all had portable oxygen monitors which alarmed at
19 19.5 percent and decreasing. The only alarms received by any
20 of the rescue people were on the 54-foot elevation of the
21 building, two floors below the diesel building, which is on
22 elevation 102.

23 MR. MICHELSON: Okay.

24 MR. LEWIS: I'm just way behind my colleagues. I'm
25 still trying to understand the safety significance of this

1 plant to the plant if the plant had been in operation. Is the
2 safety significance that CO2 might have gotten to the control
3 room and adversely affected the operators, or is there another
4 safety significance I missed?

5 MR. MICHELSON: The real problem might have been the
6 same problem with the CO2 control panel. If the actual
7 inadvertent actuation had been in the room below the control
8 room and they had dumped ten tons into there, it might have
9 been a very interesting safety significance.

10 MR. LEWIS: So the safety significance is that it
11 could have happened elsewhere in the plant.

12 MR. MICHELSON: That's the real problem, in my mind.

13 MR. WYLIE: As I understand the system, it serves
14 many areas, including the area under the control room, as was
15 outlined a while ago.

16 MR. BLAU: That's correct.

17 MR. MOELLER: How much CO2 would it take to shut the
18 diesels down on the air intake?

19 MR. LEWIS: It doesn't mean they were simultaneous.

20 MR. MOELLER: The diesels need oxygen.

21 MR. EBERSOLE: They operate from outdoors. They
22 didn't have CO2 in the combustion chambers. They may see CO2
23 in the cooling environment of the generators if they are CO2
24 protected in the engine rooms. In that case, they close up
25 and lose their generator cooling.

1 MR. HENDERSON: The presumption is if you discharge
2 the CO2 to the engine room itself, at that engine, that
3 diesel generator is an operator, but the combustion area
4 intake is from outside.

5 MR. MICHELSON: The other safety significance, of
6 course, is the seismic qualification of the Cardox panels. It
7 isn't qualified, so one wonders during an earthquake do you
8 expect ten tons of CO2 to be released here, there or
9 everywhere. It's a concern any time you get an inadvertent
10 actuation.

11 MR. WARD: The risk is that person will be disabled?

12 MR. MICHELSON: I don't think there is any
13 mechanical risk. I assume there were prudent designers and
14 designed for the dump of the full capacity of the system
15 anywhere. If they haven't, they have got to go do their
16 homework.

17 MR. EBERSOLE: They do not do this. Even TVA --

18 MR. MICHELSON: I don't know that they do or they
19 don't, Jesse. I know TVA blew some rooms over there.

20 MR. WYLIE: My experience goes back many years with
21 hydro units where they always used CO2 for extinguishing fires
22 in generators, but they always have pressure release. Very
23 simple pressure release higher in the machine to make sure you
24 don't overpressure the machine when you shookt them.
25 Generally those are multi-bottle types installation.

1 The first shot is one shot, one or two bottles, and
2 then you have an orifice release to the rest of the bottles.
3 But now these are bulk systems and they are relying strictly
4 on electrical controls to release the timed release. So it's
5 a different application.

6 MR. NICHELSON: I assume there are blowout panels
7 for it. I don't know that for a fact.

8 MR. WYLIE: All it does is lift a flapper.

9 MR. WARD: Mr. Rossi, we have got a variety of
10 opinions from the committee on the safety significance.

11 MR. ROSSI: I think the safety significance clearly
12 in these kinds of things is the inadvertent actuation of any
13 fire system that may interfere in any way with either
14 personnel or with equipment.

15 I think Ron Hernon wanted to say a couple of words.

16 MR. HERNON: Ron Hernon with NRR.

17 A piece of information we didn't have for the
18 subcommittee the other day was that there was a generic issue
19 that is presently being prioritized by Nuclear Reactor
20 Regulation. It's Generic Issue 57, and we would expect the
21 prioritization to be completed within the next month or two.
22 Inadvertent actuation of fire protection systems.

23 MR. ROSSI: I think the safety significance that
24 they will be looking at is whether the inadvertent actuation
25 of fire suppression systems, period, whatever they may be, can

1 interfere with either equipment or personnel and therefore
2 affect the safety of the plant. The generic issue would be to
3 determine whether that should be looked at generically across
4 the board in terms of looking to see if what is being done
5 today is adequate or not.

6 MR. LEWIS: You understand what's troubling me. I'm
7 trying to separate the regulatory significance from the safety
8 significance, and as I understand it, the issue of the safety
9 significance, at least having heard the different opinions of
10 my friends and colleagues, is not yet entirely clear. There
11 are several things that could have happened, if this had (a)
12 happened in another place, if it happened in conjunction with
13 an earthquake, as Carl said, or other ways that haven't really
14 been thought through yet.

15 Is that really the situation, that there is some
16 potential safety significance, but nobody is quite clear
17 exactly yet what the most serious issue is?

18 MR. ROSSI: Or to what extent it exists and how
19 probable it is, and that would be what the generic issue would
20 address, precisely that.

21 MR. LEWIS: That's what I was concerned about.
22 Fine.

23 MR. MOELLER: Is the generic issue only for CO-2, or
24 does it include water?

25 MR. HERNON: It includes CO-2 and water.

1 MR. WARD: What about halon, for example, is it
2 general?

3 MR. HERNON: It's general.

4 MR. EBERSOLE: Any further questions?

5 [No response.]

6 MR. ROSSI: Jim Henderson is also going to discuss
7 an event that occurred in July at Turkey Point Unit 3,
8 involving the auxiliary feedwater pumps at that plant, and
9 that will be followed by another event which the subcommittee
10 considers to be somewhat closely related to on Turkey Point.

11 Go ahead, Jim.

12 MR. EBERSOLE: I think this presentation has as a
13 sort of a predecessor the Davis-Besse case. We find we have
14 another plant which is borderline Davis-Besse.

15 [Slide.]

16 MR. HENDERSON: I think it is rather interesting
17 that the Turkey Point came along not that long after
18 Davis-Besse, and there is a similarity, although there are
19 some significant differences, too.

20 Last Tuesday I presented the subcommittee a
21 discussion of the event of July 21-22, Turkey Point, Unit 3.
22 Although I couldn't answer all the questions, a decision was
23 made to present this to the Full Committee.

24 I have attempted to acquire answers to the
25 subcommittee questions and in that process have had telephone

1 conversations with representatives of the Licensee, as well as
2 the Staff.

3 This has resulted in acquisition of some conflicting
4 information which I have not been able to completely resolve.
5 Some of the chronology of events is even in the
6 characterization, such as low vs. high steam generator level,
7 are not entirely clear. I believe that these ambiguities do
8 not affect the overall validity of the presentation.

9 For example, as will be explained more fully later,
10 the Licensee challenges my characterization of all three
11 auxiliary feed pumps as inoperable. I got some volunteer help
12 yesterday that I could have gotten along, I think, better
13 without. It must be understood that I was not directly and
14 personally involved in the event, and all that I report may be
15 properly considered to be hearsay, although I believe it to be
16 the truth as it was related to me.

17 So now let me go on with this, with the event.

18 On the evening of July 21, 1985, both Turkey Point
19 Units 3 and 4 were operating at 100 percent power. At 11:41
20 p.m., Unit 3 tripped off line. Unit 4 was unaffected. The
21 Licensee attributes the trip to electronic noise generated by
22 a lightning strike.

23 Unit 3 has two half-size electric drive feed pumps.
24 These pumps have constant speed drives and regulate feedwater
25 flow by flow control valves.

1 Initially the flow control valves acted to reduce
2 flow and the feedwater pumps remained at service supplying
3 water for post-trip heat removal.

4 However, this rapid flow reduction was not easy to
5 control, and two minutes after the unit tripped, the feedwater
6 pumps tripped on steam generator signal.

7 It is not clear whether the steam generator level
8 condition was too high or too low. The main feed pump trip
9 generated an auxiliary feedwater pump start signal. All three
10 auxiliary feed pumps started automatically and performed as
11 designed.

12 The unit was stabilized and preparations were made
13 to restart the unit.

14 The main feed pump reportedly was started at 11:50
15 p.m., and at about 11:58, steps were initiated to return the
16 auxiliary feed pumps to standby condition.

17 The A and C pumps, which comprise one train, were
18 placed in standby condition without apparent difficulty.
19 Problems were experienced with flow control valves for the
20 feed pump and troubleshooting was initiated.

21 The flow control valve reportedly would not respond
22 to automatic or manual position signals. It was stuck in an
23 open position.

24 At about 4:05 a.m., while feedwater flow and steam
25 generator level were being controlled by both flow valves on

1 the main feedwater system and troubleshooting on the B pump
2 was still in progress, a high level steam generator trip
3 occurred.

4 All three auxiliary feed pumps started
5 automatically. The A and C pumps apparently were placed in
6 standby without difficulty, promptly tripped and on mechanical
7 locked out overspeed trip.

8 The B feed pump, which had been placed in an
9 abnormal configuration for troubleshooting, started more
10 slowly and the speed was controlled by an electronic overspeed
11 element.

12 Mechanical overspeed devices.

13 The Five-All type, which trips the steam stop valve
14 and must be manually locally reset. The electronic overspeed
15 sensing device acts on the hydraulic governor to reduce speed
16 to a lower speed setpoint where it returns control to the
17 hydraulic for reasons I don't fully understand.

18 The governor allowed the turbine to again overspeed
19 to be intercepted by the overspeed sensing device, and the
20 turbine pump was cycled on about a three-to-five second
21 period.

22 The flow regulating valve was stuck and closed. The
23 steam generator fluctuated with the pump C. However, the
24 steam generator water was being supplied to the steam
25 generator and the quibble between me and the Licensee is

1 whether because it was not subject to either automatic or
2 manual control, it was operable or not.

3 During the telephone call yesterday afternoon, the
4 Licensee representative objected to my position that the B
5 feed pump was inoperable.

6 MR. WARD: You mean, Jim, the pump was running and
7 supplying water, but it wasn't controlling --

8 MR. HENDERSON: It was running and supplying water
9 on the cyclic basis, and it was restoring low steam generator
10 level on the sort of a ratchet basis. It did bring the steam
11 generator level within normal limits.

12 MR. ROSSI: Dan McDonald from NRE would like to add
13 something here.

14 MR. MC DONALD: I am Dan McDonald, Project Manager
15 for Turkey Point.

16 In discussions with both the resident and the
17 Licensee, the steam generator, it was the C steam generator
18 that had the open valve, and the second event was a low-low
19 level in the B steam generator, which initiated the actuation
20 of aux feedwater, and during the event, even though at the
21 control room the indication was erratic for the B pump, the
22 rpm was constant, which was observed down at the auxiliary
23 feed pumps, and the Licensee indicates the water level was
24 recovering in the B steam generator. And the failure of the
25 flow control valve to the C steam generator did not allow for

1 the aux feedwater to get to the C steam generator. But the
2 main feed was still feeding the C generator.

3 They did within about five minutes get the A feed
4 pump operable and were feeding feedwater via train number one
5 to the C generator.

6 MR. EBERSOLE: Let me comment at this point and ask
7 you to verify all of these pumps are turbine-driven.

8 MR. MC DONALD: Yes, sir.

9 MR. EBERSOLE: You mentioned a stuck valve. What
10 valve was that?

11 MR. MC DONALD: It was a flow control valve to the C
12 steam generator.

13 MR. EBERSOLE: The predominant habit of safety
14 reliefs sticking open, everybody knows about that, and here
15 you will subsequently hear that the isolation valves between
16 steam generators in this case cannot close under certain
17 conditions.

18 MR. HENDERSON: I think there is a misunderstanding
19 there. As on the main feedwater system, the pumps run at
20 constant speed. The control of flow to the steam generator is
21 by a flow regulating valve in the pump discharge, and there is
22 no overpressure protection involved in this. But the flow
23 regulating valve has a pneumatic actuator, and that was where
24 --

25 MR. ROSSI: I think your concern is if you get a

1 stuck-open safety valve, you would lose the steam --

2 MR. EBERSOLE: Driving it to all pumps. Because you
3 will subsequently hear the isolation valves don't work between
4 steam generators.

5 MR. ROSSI: I understand your concern. I would like
6 to point out a couple of things. On this plant, it is not
7 typical to lift the cold safety valves on a trip. In some B&W
8 plants that occurs fairly frequently. So that's the
9 difference.

10 Another difference between this plant and let's say
11 Davis-Besse is that this plant has considerably more inventory
12 in the steam generators than does a plant like Davis-Besse.

13 Another thing -- I'll ask Dan McDonald to tell you
14 in just a minute about the electric-driven start-up pumps that
15 are available at the plant, and although they are not
16 safety-related, certainly significantly increase the
17 reliability of having feedwater for the more credible kinds of
18 events like trips to the plant, losses of main feed and that
19 kind of thing.

20 Let me say one other thing before I turn it back
21 over to the people that are supposed to be talking about it.

22 On the safety significance of an event like this,
23 let me address that just a minute. We have got three turbine
24 driven auxiliary feedwater pumps. We design plants for the
25 single failure criteria, and when we see problems with

1 multiple redundant components in a system, we get concerned.

2 MR. LEWIS: I agree with you.

3 MR. ROSSI: We are particularly sensitive at this
4 point in time obviously to problems with turbine-driven
5 auxiliary feedwater pumps. That might indicate common mode
6 failure.

7 So this whole area is being looked at quite
8 carefully from the standpoint of things that we can make the
9 industry aware of, or we can ask the industry to do, to try to
10 eliminate any kind of common mode failure elements in these
11 kinds of events.

12 That's the safety significance of this one, that
13 there were problems and you can argue about how inoperable the
14 system was or was not, but there were problems with the
15 redundant portions of the system, and that is something that
16 concerns us, and we are still looking at this event, and
17 obviously we are still looking at the problems --

18 MR. WARD: I don't think you have to convince us of
19 this one. Even the committee understands this one.

20 MR. LEWIS: But therefore it would be nice to go a
21 little bit deeper into why the A and C tripped on overspeed
22 instead of arguing about whether ratcheting was an
23 inoperability on the B pump.

24 MR. ROSSI: I agree with you. I don't know whether
25 you have any more to add on the cause, but this one has

1 continued -- is going to be continued to be looked at.

2 MR. EBERSOLE: One small comment before we get into
3 the mainstream again. This is Turkey Point. It's in
4 hurricane country, and the scenario, the pall that hangs over
5 it, it may experience an ACL power outage for a very long
6 period of time. In that case, these two units --

7 MR. ROSSI: That is correct. Those are the
8 safety-related pumps.

9 I think it is worthwhile describing the electric
10 ones.

11 MR. WARD: This is a point that I don't think has
12 come out, that there are three aux feed pumps, 100 percent
13 capacity, but they serve both units.

14 MR. EBERSOLE: That is right.

15 MR. WARD: And there's a lot -- apparently the
16 design of this plant, there's a lot of shared equipment
17 between the two units.

18 MR. HENDERSON: That's true. It seems to me it's
19 more than has typically been allowed by the Staff.

20 MR. LEWIS: And two of those three failed.

21 MR. MC DONALD: Gentlemen, if you'd like, I can
22 describe at least what they believe was the cause of the
23 overspeed and mechanical trip on the A and C pump. There's a
24 steam inlet valve on the trip and throttle valve. When you
25 reset the system, you are to open the trip and throttle valve.

1 and then close the steam inlet valve. When the pumps roll
2 dead, then they go down and operate the knob on the governor,
3 which allows a piston to move up and dump the oil that's in
4 the governor.

5 There's another orifice, but it's very small and it
6 takes, I believe, on the order of about 30 minutes to drain.

7 What they believe happened on that night when they
8 were down troubleshooting on the B pump and the C flow control
9 valve on the C steam generator, that the operator in the
10 control room noted that the trip and throttle valve had been
11 left closed and not opened, according to procedure, which
12 trapped steam between the steam inlet and the throttle valve.

13 When he opened that valve, it caused the turbines to
14 roll, which pumped oil back into the governor. Then when they
15 got the signal in a short time, the second initiating signal,
16 there was already oil in the governor that caused the
17 overspeed. They believe that's the case.

18 MR. ROSSI: I would like to say something else about
19 an event where it is my understanding the problem was after
20 the trip, after the pumps had gone a while and when they had
21 been shut down and restarted. That's correct, isn't it?

22 MR. MC DONALD: Yes.

23 MR. ROSSI: I'd like to point out after these plants
24 are down for a while, the decay heat level and the stored
25 energy and so forth in the reactor coolant system, a lot of

1 that is much, much lower. So there is some additional margin
2 for getting these things restarted, you know, when you're
3 essentially at hot standby and you have problems.

4 Nonetheless, I think we all understand the
5 significance of it, and it is going to be continue to be
6 looked at in terms of possible generic implications to
7 eliminate common mode failures.

8 MR. MICHELSON: A couple of questions.

9 The first one on auxiliary feedwater for pressurized
10 water reactors.

11 Does the Staff consider it acceptable to have to
12 reset the turbine from the local position?

13 MR. MCDONALD: Normally they are automatic reset, I
14 understand, on turbines used on BWR designs. In this case it
15 was accepted by the Staff.

16 MR. MICHELSON: I'm asking pressurized water now,
17 not boiling.

18 MR. MCDONALD: I appreciate that. I'm not sure at
19 the time the evaluation was done that it required a local
20 reset; however, the Licensee has, I believe, some 16 different
21 actions that they are taking related to aux feedwater. One of
22 them is going to put an automatic dump in the oil system for
23 the governor so it will not require local reset.

24 MR. MICHELSON: That leaves the second question.
25 G.E. had these kinds of problems with overspeed for a couple

1 of years and finally worked out some good solutions and don't
2 have any move overspeed problems. Don't those good solutions
3 somehow get over to the pressurized water folks?

4 MR. MCDONALD: I believe the modification with the
5 governor and high pressure steam inlet for the turbine drive
6 was fairly recent as a result of the TMI modifications on aux
7 feedwater.

8 MR. MICHELSON: With G.E. they solved this thing a
9 year or two ago. Is it now required that the pressurized
10 water people go and put these fixes on that G.E. learned how
11 to do?

12 MR. MCDONALD: I'm not aware of any requirement.

13 MR. MICHELSON: Isn't there something funny about
14 our regulatory process that is a barrier between these two
15 types?

16 MR. EBERSOLE: That fix has not yet got to GESSAR
17 II.

18 MR. MICHELSON: No, no, Jesse. The GESSAR II
19 people, that's different. They said it was fixed. Remember,
20 I asked the question.

21 MR. EBERSOLE: The narrative states otherwise.

22 MR. BEARD: Carl, maybe I can help you on this one.
23 As you know, I was one of the guys that was up to "Messy"
24 Davis. They had turbine troubles. Part of the solution
25 seemed to reside in areas that the border people had already

1 addressed. One of the things we tried to point out to them
2 was there was a post-TMI requirement that each utility develop
3 a system for reviewing operating experiences at their plants
4 and at other plants. I forget exactly the title and the
5 reference number, but that's not important.

6 MR. MICHELSON: I recall.

7 MR. BEARD: One of the things, I believe, that NRR
8 is relooking at a result of the "Messy" Davis event is are the
9 utilities really reviewing operating experience at other
10 plants to the full capability they should because the very
11 thing that you pointed out we pointed out to them, that the
12 Terry Turbine folks and the Limitor Works and Woodward
13 governor folks have already worked extensively in this area on
14 these turbines.

15 So I suspect personally that there will be a lot of
16 improvements and a lot of attention brought to PWRs reviewing
17 operating experience on boilers where it is related
18 equipment. But obviously, I can't speak for Mr. Denton, but I
19 personally expect he will in that area.

20 MR. MICHELSON: Apparently it was lucky in this case
21 somehow, I guess.

22 MR. ROSSI: I would like to suggest unless somebody
23 has some additional questions or Jim has something --

24 MR. LEWIS: I wanted to say one word in support of
25 Carl's concern. Viewed superficially, this appears to be an

1 event which merits a sense of alarm. We have got a triply
2 redundant safety system which sort of worked one-half; that
3 is, 2-1/2 parts of it failed in the sense that the third pump
4 was working but was not entirely controllable in the sense --
5 that would seem to me to be a cause for a kind of high
6 priority alarm and concern on the part of the Staff.

7 I wonder if it is.

8 MR. ROSSI: As a measure of our level of concern, we
9 pick out the events that we think are significant to come down
10 and tell you about. This is on our list. We are concerned
11 about it. Davis Besse has highlighted the general problem of
12 common mode failures and problems with turbine-driven pumps.
13 I think at this point in time I would say there is a
14 considerable amount of alarm on these kinds of issues.

15 MR. LEWIS: I understand that you understand it, but
16 if I were an antinuclear outsider, I would be screaming "Why
17 don't you shut down these plants? Your safety system isn't
18 reliable, primary safety system."

19 MR. REED: I think it is opportune to break in a
20 little bit with philosophy and get farther above the nuts and
21 bolts issue, which I see someone has recommended that we work
22 above. Mr. Rossi has just recommended or tried to bring us at
23 an intermediate plateau above nuts and bolts in talking about
24 components that are similar in a one-principle system,
25 auxiliary feedwater, for the removal of decay heat.

1 Now, what hasn't been said and wasn't brought before
2 the subcommittee is that there were two other auxiliary
3 feedwater system failures in the last two months, I believe
4 one at Salem and one at Smud, another B&W. The interesting
5 thing to me, and what should be interesting to ACRS, is that
6 auxiliary feedwater on some PWRs seems to get into problems,
7 and perhaps auxiliary feedwater from an ACRS viewpoint should
8 be looked at very hard as to whether or not that single decay
9 heat route or path is adequate in the long run for some PWRs.

10 MR. WARD: Mr. Wylie.

11 MR. WYLIE: I just had one observation. It's
12 interesting to note, both here and "Messy" Davis and Turkey
13 Point, that the equipment that was assured safety was
14 nonsafety related.

15 MR. ROSSI: That is a point. We certainly cannot
16 cross out the importance of the nonsafety-related equipment
17 that is on these plants.

18 MR. WYLIE: The reason I make that observation is
19 there seems to be a trend that if it's not safety-related, you
20 discount it, you don't use it. I think we can learn something
21 out of that.

22 MR. ROSSI: I think we have covered the main aspects
23 of everything we had to say, and I would suggest that we go on
24 to discussion of the MSIV failure at Turkey Point unless
25 anyone has an objection.

1 MR. EBERSOLE: This is an interrelated matter since
2 this provides a means to commonly bleed down all steam
3 generators and thus lose the driving head for the turbine
4 points. Same plant.

5 MR. ROSSI: For this one we will have Vern Hodge of
6 the Office of Inspection and Enforcement discuss the MSIV
7 problem at Turkey Point.

8 MR. EBERSOLE: While he is getting geared up, let me
9 comment. John McAvoy make a study of all the aux feed pump
10 configurations, and may plants have just two pumps. Most of
11 them have an electric pump and a turbine pump, so by no means
12 to all of them have three pumps, two motor and one turbine.

13 MR. LEWIS: Three don't seem to do you much good
14 when they all fail. I would view this with great alarm.

15 MR. EBERSOLE: This is a critical safety system.

16 MR. LEWIS: I would hate to see it shoveled into a
17 generic study that would last three years. There seems to be
18 a real emergency.

19 MR. EBERSOLE: There appears to be much more reason
20 to shut a plant down for this reason because it supports LOCAs
21 under the steam generator for supports. Plants have been shut
22 down for far less important reasons.

23 MR. HODGE: Good morning. I'm Vern Hodge from IE.

24 In July NRC received a Part 21 report from Turkey
25 Point units about the potential for the MSIVs to fail closed

1 under low steam flow conditions.

2 MR. EBERSOLE: To fail open.

3 MR. HODGE: They would not close.

4 MR. EBERSOLE: Yes. You said fail closed.

5 MR. HODGE: Failed to close. Sorry.

6 So two issues can be discussed here. One is the
7 Licensee's review disclosed unanalyzed condition possible for
8 the main steam line break accident. The NRC inspectors
9 observed inadequate testing practice.

10 [Slide.]

11 This diagram shows roughly how the valve works.
12 Instrument air is fed through two accumulators to a
13 piston-operating cylinder which moves the shaft up or down to
14 close or open the MSIV. Essentially this problem occurred --
15 also, to assist the closure, partial engagement spring. This
16 starts the piston down. It's used mostly for testing
17 purposes. And then assisting the valve closure is steam flow
18 in the steam line.

19 Under low steam flow conditions, that is absent, of
20 course, and the problem then essentially is because the
21 accumulators are too small.

22 MR. MICHELSON: That's not what you would call a
23 fail safe design, safe meaning, I assume, full closure. A
24 failure of air supply, for instance, it doesn't fail
25 closed. Accumulator air supply.

1 MR. HODGE: I think it's a matter of scale. It's
2 designed to close.

3 MR. MICHELSON: If it's designed right, it will
4 close.

5 MR. HODGE: Right.

6 [Slide.]

7 For the main steam line break accidents, you see
8 MSIVs won't close. Testing program has indicated that,
9 indeed, they won't close under some conditions. The problem
10 applies to the Turkey Point and the Robinson plants, and the
11 problem is that a threshold steam flow is required for the
12 valves to close. This is not known exactly, so for
13 conservatism, Licensee assumes they exceed the aux feedwater
14 capability to make up so continued blowdown is possible.

15 MR. WARD: What is the line size?

16 MR. HODGE: I'm not sure. I think it's about 28
17 inches.

18 MR. WARD: Okay.

19 [Slide.]

20 Licensee justifies continued operation by
21 establishing backup systems to assure the availability of
22 instrument air. Diesel air pressure would backup the plant
23 system. Cross-ties have been arranged from the fossil plant
24 instrument system, and a procedure has been instituted to shut
25 down the plant if the instrument air supply does fail.

1 I understand in previous operating experience this
2 instrument air supply has not failed. Corrective action as to
3 change the design on an expedited basis to assure MSIV closure
4 in 5 seconds as required by the technical specifications
5 without steam flow assistance. At the same time, this design
6 modification would resolve the problem with the testing
7 practice alluded to earlier, which I will discuss now.

8 [Slide.]

9 In February, inspectors noted that the stroke
10 testing procedure did not call for securing instrument air
11 supply, and as a result, the Turkey Point and Robinson plants
12 were cited as violating 10 CFR 50.55A(g), which invokes the
13 ASME boiler and pressure vessel code, one paragraph of which
14 requires that testing of the valve, meaning observing the
15 behavior of the valve when the actuator power is secured and
16 NRC has determined that actuator power includes both electric
17 and instrument air power.

18 We are not certain how many plants this would
19 effect. We are writing an information notice on it in the
20 hope that Licensees will review their testing practices and
21 understand the possibility of the unanalyzed condition.

22 I would be happy to answer any questions.

23 MR. MICHELSON: That test requirement pertains only
24 to Robinson and Turkey Point?

25 MR. HODGE: No, sir. This is a regulation.

1 MR. MICHELSON: For all plants?

2 MR. HODGE: I believe so.

3 MR. REED: On the issue of why the valve didn't
4 close, I believe you said in subcommittee it was because
5 perhaps the calculated pressure force from the stem was not
6 taken into consideration well enough. Now, I don't understand
7 that not being taken into consideration, but generally the
8 thing that changes is packing friction. Is there a packing
9 friction aspect to this motion to close?

10 MR. HODGE: Probably so, yes. In a diagram, the
11 unbalanced force from the steam pressure down here probably
12 would be eventually balanced by the air pressure up here as
13 depleted. All the terms and equations become small; therefore,
14 the pressure it can stand is what is left within the
15 enclosure.

16 MR. REED: That should have been calculated by the
17 designer, but he should have also put in there a healthy
18 margin for packing friction and packing condition.

19 MR. HODGE: Undoubtedly that is true.

20 MR. REED: After all is said and done, you will be
21 looking at the final balance here to find out what pressures
22 are required in the top of the cylinder to cause this closure,
23 and you will find out whether the packing was, let's say, not
24 properly maintained, whether the design was in error.

25 MR. EBERSOLE: If there were a relatively small main

1 steam line break, presumably there would be a fairly slow
2 blowdown, and that might not close, I presume.

3 MR. HODGE: That's correct.

4 MR. EBERSOLE: Would that lead to containment
5 overpressurization because you would dump the contents of both
6 steam generators into one volume?

7 MR. ROSSI: I believe that would take another
8 failure of the check valve if it were a break inside the
9 containment.

10 MR. EBERSOLE: That's right. There is a dual check
11 valve. And these have been validated to close satisfactorily
12 against impact loads?

13 MR. HODGE: Yes.

14 MR. EBERSOLE: For the smaller break it would be
15 better.

16 MR. ROSSI: For the smaller break --

17 MR. EBERSOLE: Almost a compensating effect here.

18 MR. MCDONALD: One thing I want to make clear. In
19 all the tests when the instrument area is hooked up the valve
20 closes within a 5-second time. During the test it closed
21 sometimes, although it was erratic. The analysis says under
22 no flow conditions it shouldn't close within 5 seconds, and
23 that's why they presented it as a Part 21.

24 In relation to the ability of both the check valve
25 and the valve to close in impact on the seat, in 1976 the

1 Staff evaluation required licensees to look and assure when
2 the valves are slammed shut under pipe load that they don't
3 have a problem. These valves, both the main steam isolation
4 valve and the check valve, are modified, and the operator on
5 the MSIV. It could have been at that time a change in design
6 might have caused some problem, but it was not tested without
7 the plant air system.

8 MR. EBERSOLE: Okay. I see.

9 Any further questions?

10 [No response.]

11 MR. EBERSOLE: If not, Ernie?

12 MR. ROSSI: Next we have a situation on Maine Yankee
13 that will be discussed by J.T. Beard from the Office of
14 Nuclear Reactor Regulation, and this is another one that falls
15 in the common mode problem area, which we are always concerned
16 about when we see them. This is a common mode problem with
17 steam generator pressure indication.

18 MR. BEARD: As Ernie has said, when we see common
19 mode, or even potential common mode problems, we do get quite
20 concerned. On this particular one, I was involved in a
21 meeting very late last night on this one. I can give you some
22 assurance that we are definitely looking into this.

23 [Slide.]

24 The way I set up the presentation is sort of what I
25 call newspaper style. I'm going to hit you with the bottom

1 line first, and then come back and fill in with details.

2 There were two common mode problems that effectively
3 compromised the protection system at this plant for main
4 steamline breaks. A lot of the protection is actuated by
5 sensing low pressure in the steam lines. We have three steam
6 generators at this plant, and each channel has four pressure
7 detectors on it, so we are talking about a total of 12
8 transmitters that feed into four instrument channels.

9 What actually took place, the event was that in
10 early August the plant was in two-cycle coastdown. They were
11 down to about 78 percent, pressure was a little low, and they
12 found of the 12 pressure transmitters, nine were not fully
13 open. I point out that's in quotes.

14 Then after the plant did come down after that cycle
15 in September, they were running the 18-month tech spec
16 surveillance tests and they discovered that the three channels
17 that were not affected by the root valve problem were
18 essentially wiped out because a year or so ago they had put in
19 a design mod because they were going to tie into the
20 protection system instrument loops.

21 The long and the short of it is they didn't do a
22 good job on that.

23 So the end result was all 12 channels were
24 compromised. I think that also summarizes the item you had
25 down here as significance was the main line of defense on a

1 main steamline break was compromised by common mode problems
2 and the fact that these conditions had originated during the
3 refueling proceeding, and had been undetected for the entire
4 operating cycle.

5 So that was your exposure.

6 I have to jump in and immediately follow that up
7 with a comment that there is diverse instrumentation in the
8 design, and for a number of safety functions, such as tripping
9 the reactor, we fully expect that those would have actuated,
10 albeit slightly delayed, because they are in fact back-ups.

11 With that sort of bottom line, I'd like to go on and
12 give you a little more information on each of these two
13 problems.

14 [Slide.]

15 I made up a little chart here that shows what was
16 affected and what was not. As I said earlier, there are three
17 steam generators and each has four transmitters. Transmitters
18 converge into one instrument channel. Three of these root
19 valves were found completely closed. Although while they were
20 closed, they were leaking, and the rest of this set were
21 various degrees of fully closed or just slightly closed.

22 MR. REMICK: When you say leaking, do you mean
23 leaking through the valve seat?

24 MR. BEARD: Leaking through the valve and providing
25 pressure through the instrument sensing device.

1 What actually took place was as they were coasting
2 down, pressure had, of course, come down, as you would expect,
3 but they found that on steam generator No. 1, one of the
4 pressure channels was -- I guess you would call it sagging.
5 It was reading like a hundred pounds lower than everybody else
6 and was acting a little erratic. We called the I&C people in,
7 they checked out the transmitters, it was fine, the instrument
8 loops were fine, so they started checking into the sensing
9 lines.

10 When they went to blow those down, they found out
11 that they didn't behave the way one would expect. As they got
12 to looking into it more, they found out that the root valves
13 were in fact fully closed.

14 I would point out the one they found over here was
15 steam generator No. 1, channel No. D, and that root valve was
16 fully closed.

17 A subtlety I would like to emphasize is while the
18 root valve was fully closed, the indicators in the control
19 room were indicating reasonable and normal values. This is
20 because of the leaking that I pointed out, that they were able
21 on a steady state basis to eventually charge up the line and
22 read something.

23 So the real problem was one of what would they do in
24 a transient type condition. The reason they got into this
25 situation was in a previous refueling they had blocked off or

1 wanted to block up instrumentation in order to protect it, in
2 order that they can conduct a hydro test on the steam
3 generators.

4 An interesting thing is you notice the A channels
5 apparently were not affected. The reason for that is really
6 all 12 of them had been closed. It was providential that they
7 had another piece of work that involved an Appendix R
8 modification that had a specific step in it that said go back
9 on the ones that we are using for Appendix R shutdown margins
10 -- shutdown panels and make sure these things will reopen.

11 So these things have the problem, but through a sort
12 of a separate act they were taken care of.

13 Going back here, the problem comes up that, like I
14 said, that part was just providential. The root problem seems
15 to me to be that these valves were not on any sort of
16 checklist, not on any administrative controls whatsoever, and
17 the Licensee makes the case, explains that although he
18 realizes today that's invalid, his assumption had been that
19 if the instruments are reading properly, then it's obvious to
20 everybody that the root valves must be okay.

21 Well, he's learned his lesson now. The Licensee did
22 run some tests, not very quantitative and not highly
23 scientific, but they were trying to get a feel for what might
24 have been the response they could have expected from these,
25 and depending on exactly how far they are closed down on these

1 root valves, stop to stop is about five and a half turns.
2 It's just like a faucet at your home, for your garden hose,
3 depending on how tight you turn it down or how open it is, you
4 could get responses as slow as 30 or 60 seconds type delay.
5 But they were -- except for the ones that were fully closed,
6 they would eventually have gotten there.

7 [Slide.]

8 Here is another cartoon I drew up to try to show up
9 how these instruments actually come together. This one
10 depicts a typical instrument loop, where you've got the
11 pressure transmitter with the instrument tube actually coming
12 into it.

13 Of course, upstream of that is the root valve we
14 were talking about earlier.

15 Inside the little dotted box are some parts of the
16 instrument loops that are power supply and test connections
17 that aren't related to this event.

18 Basically, as you know, the transmitter puts out a
19 current through the loop four to 20 millionth corresponding to
20 the pressure the transmitter sees. The way you get signals
21 out of this loop is by letting that current run through
22 resistors and tapping the whole result into various circuits.

23 As I said, up at Maine Yankee, they take these three
24 transmitters say in the design failures, safety function is to
25 detect low pressure. So we'll go through a black box that we

1 will call auctioneering low, we'll find out which of these
2 three is the lowest pressure signal, allow that to go into
3 your bi-signal trip unit, and if it's low, it trips.

4 [Slide.]

5 The situation that they got into was they were doing
6 a post-TMI related modification, that of installing subcooling
7 monitors in the reactor. TMI requirement was that they have
8 monitoring in the core which would use like core exit
9 thermocouples and reactor coolant system pressure, on
10 recommendation of Combustion Engineering.

11 The utility, through their engineering organization,
12 Yankee Atomic, decided they would go beyond that and actually
13 monitor the subcooling conditions in the dome of the reactor
14 vessel, and also pick off temperature-pressure-related signal
15 to steam generators.

16 What they were trying to do was to go into the steam
17 generator pressure channels, tap off a signal and use that as
18 one of the inputs to their shutdown cooling monitor channels,
19 one of many different inputs.

20 The basic problem they got into was they wanted to
21 be able to switch these various transmitters into their
22 circuitry. They've got three pairs of wires and they realized
23 if we could do this with a single pulse switch around one
24 side, we don't have to switch the other one, we can save a
25 little money by a cheaper switch.

1 The end result was they established a new ground --
2 I want to put that word in quotes, common return, whatever you
3 want to call it, so that they could make the switching easier.

4 Now, the mistake they got into was they did not give
5 any consideration apparently to whatever grounding might be in
6 the reactor protection system. So now you end up basically
7 with one circuit and two grounds in it, and that's not good.

8 We did resume the design change package. You have
9 to realize that people are going to make mistakes and the
10 regulatory approach is to design some system that will provide
11 assurance that the mistakes that do occur will be caught. The
12 design review process didn't even address this.

13 The post-modification testing was limited very much
14 to the extent, okay, we wanted inputs to our subcooling
15 monitors, do they now work. The answer is yes.

16 Question: Do they look at the RPS system that we
17 are interfacing with? The answer: No.

18 Another interesting aspect of this is, as I said
19 earlier, this was done during the refueling outage. Every 18
20 months the tech specs require they do a very elaborate test of
21 the instrumentation for the protection system and the
22 engineered safeguards actuation system.

23 They did that test, got their X in the square like
24 in April, and the following month made the design mod and did
25 not see any need to repeat the testing. So that's why the

1 thing went undetected.

2 They do have more frequently a monthly functional
3 test that the tech specs require them to do. While I haven't
4 looked at all the details of it, the Licensee made it very
5 clear that the way they performed that test, it's inherently
6 not capable of picking up this problem. So that's why the
7 situation went undetected for the entire operating cycle.

8 I should say it's not in the handout, but this
9 particular utility has really been set back on their heels by
10 this discovery, these two discoveries, common mode problems.
11 The utilities plan a lot of corrective actions, some of which
12 are obvious; like, for example, now all the root valves are on
13 the checklist of administrative controls. They are very
14 concerned that this modification got them into hot water and
15 it escaped all their nets that should have caught it.

16 So they are concerned to the extent that they have
17 now launched a major re-review of every design change that has
18 ever been made on that plant, that either directly involves or
19 interfaces with the reactor protective system or engineered
20 safety features, actuation system as an independent design
21 review.

22 They are backing that up by a proposal to do very
23 comprehensive tests of all the instrumentation, safety-related
24 instrumentation, hopefully to detect these and similar type
25 problems, and they feel so upset by this that they are

1 voluntarily keeping the plant down in order to complete this
2 activity, so that they have a better handle on what will this
3 protection system and what will it not do. Because at this
4 point the utility has said flat out they don't know what they
5 have got.

6 MR. LEWIS: I'm glad to hear that they are taking
7 this seriously.

8 For the record, it's interesting that this is the
9 second major problem that has been discovered as a consequence
10 of the installation of the subcooling meters. Of course, the
11 Crystal River accident was a major consequence of a subcooling
12 installation. The subcooling meters were only one of the --
13 I'd like to call the Crystal River an iatrogenic one, and this
14 is an iatrogenic design problem.

15 The subcooling meters were only one of the many mods
16 that were imposed after TMI, and I wonder whether there's a
17 generic problem there in terms of the old adage, that if
18 something ain't broke, don't fix it. That is, this is two so
19 far discovered as a consequence of just the subcooling meter.
20 I wonder if you think there's any other generic issues
21 associated with the very rapid rate of modification of plants
22 in the aftermath of TMI?

23 MR. BEARD: I share your concern. NRR is looking
24 into this very carefully, in this just area. We realize not
25 only post-TMI -- Salem fixes, a lot of other fixes. But the

1 utilities, by and large, are hanging a lot of stuff on the
2 safety-related instrumentation these days, not only for those
3 kinds of reasons, but one side of the NRC is going out doing
4 control room design reviews. Apparently that's prompting
5 additional indicators and things of this nature, so we are
6 concerned that they are hanging a lot of stuff on it.

7 I said to the subcommittee the other day that when
8 we wrote a letter, those post-TMI fixes and the Crystal River
9 fixes and whatnot, we did feel it was necessary to tell the
10 utilities, when you make modifications, don't screw it up.

11 I'm not so sure that was the correct thing to do. I
12 think we should have said it, but any time you ask a utility
13 to modify his plant, you run the risk that it doesn't get done
14 properly, and I think that's what we're seeing.

15 My personal opinion is, well, some of these are very
16 notable messes that they have gotten into. If you look over
17 all of the number of changes that have been made, the number
18 of plants -- the overall numbers that we're talking about, I
19 personally am surprised that there have been this few. But I
20 think we as regulators need to recognize that as you said, if
21 it's not broke, don't fix it.

22 Any time you upset the apple cart by any change,
23 there's also a downside to that decision that has to be
24 addressed, or at least cannot be ignored.

25 MR. LEWIS: That's exactly right. I agree with

1 that.

2 MR. OKRENT: On the same point, I hate to let the
3 other aspect of this same issue not be mentioned. Utilities
4 should be able to make these changes directly.

5 MR. LEWIS: That was the next thing I was going to
6 say. I agree completely with you, Dave. In fact, in this
7 particular case, when you have add-to electronics, I thought
8 most people know that you should be careful about common
9 grounding or commoning problems. That's a fairly elementary
10 error to have made.

11 MR. BEARD: I agree. I brought this up to the
12 utility's management a day or two ago, and told them just that
13 point. I thought it was a very elementary problem they got
14 themselves into. I guess the only thing I can say is in all
15 honesty, I never cease to be amazed at these plants. This
16 modification was, by the way, done locally, local approval
17 under the provisions of 10 CFR 50.59. It was only because
18 they had an event that it came to our attention.

19 MR. WARD: What do you mean, it was done locally?
20 Local approval?

21 MR. BEARD: What I mean is local approval is when
22 the utility designs and reviews the mod and makes the final
23 approval to install this modification and the NRC is not
24 involved in that review and approval process.

25 MR. REMICK: I assume they reported that to you on

1 the 50.59, their annual 50.59 report presumably had that
2 information in it?

3 MR. BEARD: I have not gone back and rechecked this
4 particular item, but I presume they met the regulation. They
5 gave us a list of all the modifications they put in the plant
6 the last year or two.

7 MR. SIESS: But nobody looked at it?

8 MR. REED: Could you walk me through the fundamental
9 safety significance of, let's say, these two things related to
10 pressure, loss of rapid pressure response on steam line
11 breaks? Walk it through to where it might interface or cause
12 or lead us to potential for core melt.

13 MR. BEARD: I'll give it a shot. I have to say we
14 have not completed our review, as you can imagine. This thing
15 just came up.

16 Let me say as I get started here, the Licensee has
17 done an analysis of just what you are bringing up, Glenn.
18 They did an analysis that started out with saying, okay, let's
19 just postulate all of our pressure instrumentation is dead,
20 for whatever reason. They we will go on and we will say what
21 piece of equipment or actuations would be presumed reasonably
22 to be disabled by that, and secondly, what pieces of
23 instrumentation or equipment could we reasonably presume would
24 still be available?

25 Then we went through all the analytical calculations

1 with the computer codes and whatnot, and they came up that
2 because of the backups, it looks as though the plant would not
3 return to criticality and return to power, that that would
4 still be precluded; but there are some parts of that -- we
5 have not reviewed that analysis yet. Let me tell you what I
6 think we know about it.

7 On main steam line situation -- and Ernie, please,
8 if I make a mistake, please correct me -- there are three
9 things you generally want to do. One is to isolate the steam
10 side of the steam generator. Most plants use MSIVs for that.
11 The second one is you want to isolate the main feedwater side
12 to curtail the amount of overcooling you get, and the third
13 function is related to getting your aux feedwater up and
14 running.

15 MR. EBERSOLE: Don't you protect the containment
16 from high pressure by turning off the feedwater as well?

17 MR. BEARD: Yes. That's one of the other reasons
18 for it. You are correct, Jess2.

19 At this particular plant, the way they isolate the
20 steam side of the generators is through what they call excess
21 flow check valves. These check valves are operated by this
22 pressure instrumentation, so that function would be lost. The
23 way they isolate main feedwater is through another gadget -- I
24 have forgotten what it was -- but those gadgets are operated
25 when the excess flow check valves operate, so they would be

1 lost, so feedwater isolation valves would not be totally
2 closed.

3 They realize -- and if you look in their accident
4 analysis section of the FSAR -- that if you don't shut off aux
5 feedwater, isolate it, that all the water goes into the break
6 and that makes it quite bad. So one of the safety functions
7 is to isolate the aux feedwater system to feed the break, and
8 that function would be lost also.

9 In their analysis they say if, however, we take
10 credit for the reg valves in the feedwater system and assume
11 that they will close because we will get high steam generator
12 level on the swell due to the break, which will give you
13 turbine trip, which will come back and give you reactor trip
14 and isolate at least the feedwater system of running it back
15 or completely closing it, if we take credit for the reg valve,
16 then we will get some help in that area. That's normally not
17 allowed in the licensing process.

18 The end results of their analysis are that if we get
19 credit for that kind of thing -- this is a best estimate
20 kind of thing, not licensing analysis -- it looks like they
21 will get a backup reactor trip on the steam generator high
22 level pretty quick. If not, they will get it in something
23 like 5 seconds, according to their analysis, because of the
24 containment high pressure signal tripping.

25 They didn't give us a whole lot of information on

1 what is going to happen in the secondary side, and we had some
2 serious questions in that area, but they did really look at
3 this question of would the reactor return to power, and they
4 believe that it will not if you take reasonable best estimates
5 type analysis and use credits for nonsafety-related things, as
6 Charlie was bringing up. But in the licensing space, that
7 doesn't hold water. We are trying to focus our attention, at
8 least on the side of the effort that I'm working with, in what
9 I call the real safety issues of the concern and try not to
10 trip over our sneaker strings in the regulatory aspects.

11 I'm not sure how well this answered your question.

12 MR. REED: I think that's what I want to know, was
13 it really significant with potential for core decay heat
14 removal in jeopardy. It doesn't look like another arrow for
15 my quiver. I keep trying to store arrows.

16 MR. WARD: You need another quiver, I think.

17 MR. SIESS: Back to the issue of whether changes are
18 made correctly. A lot of errors that are made during
19 construction are detected during the preoperational testing;
20 am I correct?

21 MR. BEARD: On a new plant you are absolutely
22 correct, and that's what we hope for.

23 MR. SIESS: Is there a comparable program of testing
24 that could be expected to discover errors made in
25 modifications?

1 MR. BEARD: The answer to that question is that we
2 have made a lot of improvements in this particular area since
3 the Salem ATWS. One of the big things was a program called
4 post-maintenance or post-modification testing. They should
5 undertake a comprehensive test to make sure not only does the
6 function you are trying to add work properly but that you
7 haven't had it configured with other parts. That program has
8 just be lodged a year or so ago. It has not been fully
9 implemented at a lot of utilities.

10 We explored that very point with this particular
11 utility because they have already given us commitments on what
12 they are going to do with this kind of testing. When I was
13 talking to their management, I said, have you looked at the
14 question of whether or not you did the kind of
15 post-maintenance or post-modification test that you told us
16 you would do? That's the first question. The answer was yes,
17 we did everything we were obligated to do.

18 Second question: Were your obligations, your outline
19 of what you would do, did you consider that those were
20 adequate? Answer: Clearly they were not adequate.

21 MR. SIESS: So they did what you told them, but that
22 wasn't adequate.

23 MR. BEARD: They did not do what we told them. We
24 told them simply to propose a program of post-maintenance,
25 post-modification testing that would adequately address safety

1 concerns. They developed a program to hit that general
2 requirement. We did not tell them how to do that testing in
3 any way, shape or form.

4 MR. SIESS: You don't have to approve what they
5 proposed?

6 MR. BEARD: I think the NRC does review
7 that. Whether they issue a separate approval or whatnot or
8 whether there is reason to do that, off the top of my head I
9 can't give you an authoritative answer.

10 MR. ROSSI: Even if we were to approve it, it would
11 be an audit review. We don't go through every detail of every
12 single procedure in every program. You know, I think there
13 are a couple of lessons that I like out of this event. One of
14 them is post-modification testing. You know, you can look for
15 grounds that are in the wrong place. I just believe no matter
16 how good you are in doing that, you are probably going to miss
17 some. I really think post-modification testing is very
18 important in picking up this kind of a problem.

19 The other thing is the kind of things that cause
20 common mode failures in systems. This is a good example of
21 what we have, I think, recognized for years as possible
22 producers of common mode failure.

23 MR. SIESS: Ernie, it seems to me that raises a
24 question of why you do a review. If your review is only an
25 audit-type review and it doesn't discover the deficiencies in

1 the licensee's proposal, why is NRC wasting its time doing
2 such a review? I mean do you salve your conscience?

3 MR. ROSSI: I think the reviews we do certainly
4 place a lot of emphasis on licensees developing good programs,
5 and we follow those up with what we are doing here when we
6 find glitches in their programs. We go back and look at what
7 they are doing to correct it.

8 MR. SIESS: If you had never even done the review,
9 you would have ended up at the same point, you are telling me.

10 MR. ROSSI: We may have had more of that to do, I
11 think.

12 MR. EBERSOLE: Isn't there a ritual -- certainly
13 there is a golden rule that no piece of protective system is
14 ever bought without a price, and isn't there a ritual or
15 routine that certainly says, when you do anything like
16 this: What the hell have I done wrong?

17 MR. BEARD: There are supposed to be, Jess.
18 Unfortunately, in my personal opinion the criterion for that
19 kind of stuff is in 50.59, and it says you are supposed to do
20 a review, you, the utility, are supposed to do a review. If
21 it meets certain tests, you don't have to submit it to the
22 NRC. I think the basic root of the root problem is those
23 determinations are done in a rather superficial manner.

24 We looked at the 50.59 review of TMI. They didn't
25 address but about half the criteria. I'm a frustrated

1 engineer, you know.

2 But going back a little bit to the question of the
3 NRC reviews, I think part of the problem is this agency is
4 trying to reach some balance between taking 30 years to
5 licensing of the plant and doing a good, responsible job
6 protecting health and safety and keeping the job to a
7 manageable size. And the NRC is trying to give some credit to
8 the fact they are using good engineers to design things,
9 hopefully, and they generally are. Their Appendix B
10 requirements to 10 CFR 50, quality assurance, say you have got
11 to have designer reviews, and the corporate does all that kind
12 of thing. They have plant safety review committees.

13 By the time it gets to us, hopefully with those
14 layers of review, the government's review should find no
15 problems, and we therefore can take some assurance that we
16 don't have to review 100 percent of the plant, or we would
17 have to have just as many engineers and just as many years as
18 the architect engineer or the vendor. So you run into
19 societal kind of questions, too.

20 MR. SIESS: That sounds great, but it just doesn't
21 catch the problem.

22 MR. BEARD: Absolutely.

23 MR. EBERSOLE: Standardization in detail will catch
24 the problem, I think.

25 Go ahead, Carl.

1 MR. MICHELSON: What I wanted to ask about is this
2 problem of -- well, it's a three-part question. The first
3 part is to what extent now or how are you transmitting this
4 information to other utilities so that they take care of this
5 question of leaving valves partially open or completely
6 closed? You should tell us a little about that.

7 The next part of the question is that instrument
8 valves aren't the only problem. There are hundreds or
9 thousands of small valves which are nonmonitored and for which
10 you can't even tell their positions, necessarily, around the
11 plant, many of which can inactivate engineered safety
12 features. So why aren't you extending this on to them?

13 So the third part of the question is are you doing a
14 study of this whole question of leaving nonmonitored valves in
15 improper conditions? And I think this has to go beyond the
16 old AEOD study in which they looked at the wrong train, wrong
17 valve kind of situation, and now look at leaving these
18 unmonitored valves in various positions and there is no
19 knowledge on the part of the management that they are in a
20 nonacceptable position.

21 MR. BEARD: Let me see if I can take that question a
22 piece at a time. It is my belief -- and Ernie, correct me if
23 I'm wrong -- that I&E is considering an information notice to
24 get the word out on this.

25 MR. ROSSI: That's correct.

1 MR. BEARD: So we will let people know about these
2 occurrences and lessons to be learned from them.

3 MR. BEARD: The second part of it, if I remember it
4 properly, or in order --

5 MR. MICHELSON: Other valves.

6 MR. BEARD: It has to do with other valves in which
7 the same disease might exist. I don't know that the agency
8 has decided exactly how and who is going to address that part
9 of the generic applicability question, but I can tell you from
10 meetings even late last night the generic applicability is
11 definitely being pursued. It may turn out AEOD in a better
12 charter might be asked to look at this question again.

13 MR. MICHELSON: Is there a possibility it might be a
14 generic issue and go through that process?

15 MR. ROSSI: Valve verification, I think, has been
16 recognized as a generic problem for a number of years and has
17 been addressed and readdressed with notices --

18 MR. MICHELSON: They keep addressing big ones. They
19 don't address all the little half-inch, three-quarter inch
20 that can get you into big trouble. They recognize they are
21 there but they don't address them in the programs. I'm not
22 satisfied that you have a program presently in the industry
23 that takes care of these malpositioning of nonmonitored
24 valves.

25 MR. ROSSI: It is clear that the program is not

1 working well enough.

2 MR. MICHELSON: This is just an isolated incidence.
3 In the last year, you can go down -- fortunately, the LERs
4 don't report all of these any more because they don't have
5 to. Only when you do a whole bunch of them at once and really
6 screw it up do you even have to report it.

7 MR. EBERSOLE: May I ask this question of the NRC at
8 large --

9 MR. MICHELSON: He has got a third question.

10 MR. BEARD: I have a third answer. The answer, in
11 my personal opinion, to your third question about the generic
12 problem is we as an agency have been licensing plants on the
13 basis of single failures, and we have to come to grips with
14 this question for the common mode problems that are popping up
15 out there in the real world.

16 As the Chairman has said, we have to look at that
17 whole thing as a licensing basis, and we at NRR try to come to
18 grips with not only where is it going to happen next, how is
19 it going to happen, but what can we do to prevent it. We
20 don't have all the answers yet, but we are definitely working
21 on the problems.

22 MR. MICHELSON: My question was do you actually have
23 a study under way or are you still thinking about it?

24 MR. BEARD: A study under way on the valves or
25 common mode?

1 MR. MICHELSON: Positioning of malpositioned valves.

2 MR. ROSSI: I don't know of any particular study. I
3 do know it is a continuing concern within the agency, within
4 the regions on malverification in general.

5 MR. MICHELSON: The reason I asked is I have been
6 reading LERs from time to time over the last year and I see a
7 lot of this. It's in old LERs, unfortunately, that are now
8 beginning to phase out, so I don't see as much because they
9 aren't reporting it as much. But is there any kind of
10 organized look at what we have seen in the past when it was
11 reported?

12 I think it is almost a worthwhile undertaking.

13 MR. BEARD: We expect AEOI to do that kind of thing.

14 MR. REED: I just wanted to carry on on what Carl
15 said a little bit and what Mr. Rossi is saying. There are, of
16 course, many what are key safety-related valves that are on
17 monitor lights in the control rooms. Then there are tens of
18 thousands of other valves. Let's say nines of thousands are
19 not at all safety related, but it appears to me here the
20 check-off list was deficient.

21 Now there is verification validation into operator
22 attention -- this is a requirement -- attention to valve
23 position, so I really think what Carl is talking about, yes,
24 that's ongoing; but when you are operating and using some tens
25 of thousands of valves, invariably somebody is going to have

1 one off the check-off list or make a mistake and we are going
2 to hear about that incident, and we really want to know what
3 its significance is.

4 MR. EBERSOLE: Any other questions? I was just
5 going to ask why wouldn't it be appropriate to mandate that
6 every important valve, safety valve be sealed closed with a
7 lid seal with an individual's name on it.

8 MR. REED: I think that is a practice, Jesse, but
9 rather than having individual names, there was a number tag, a
10 plastic number tag on the valve which goes back to the
11 check-off list which says it was operated in position on a
12 certain day and it is traceable to the operator.

13 MR. EBERSOLE: I am after traceability.

14 MR. MICHELSON: The problem is, at least in a number
15 of plants I have toured I have been looking for this, and I
16 find it is good on the 2-inch and up kind of valves; I find it
17 is nonexistent on half-inch or 3/4-inch.

18 MR. EBERSOLE: I said why wouldn't all of them?

19 MR. MICHELSON: That's my problem. There's no set
20 practice in the industry that goes down to every one of the
21 half and three-quarter inch. I have rarely seen it on
22 instrument valves.

23 MR. BEARD: We were here before you some months ago
24 on a number of problems of dispositioning of isolation valves
25 and scram systems, hydraulic control units. The same comments

1 come up. The only thing I can really say in response to your
2 question is this is an advisory safety group and you may
3 choose to make that recommendation.

4 MR. EBERSOLE: I think that's right. We have to
5 consider that.

6 Any further questions?

7 [No response.]

8 MR. ROSSI: The next item is discussion of new pipe
9 crack indications which have occurred at Peach Bottom, and
10 that discussion will be led by Jerry Gears from the Office of
11 Nuclear Reactor Regulation.

12 MR. EBERSOLE: Dr. Shewmon, this was especially in
13 your direction.

14 MR. GEARS: My name is Jerry Gears. I'm the Project
15 Manager for the Peach Bottom facility at NRR.

16 [Slide.]

17 I would like to present this morning a quick
18 overview, at least as it refers to the ongoing IGSCC
19 inspection at Peach Bottom Unit-3, highlight some of the areas
20 that have been again focused because of the offense at Unit-3
21 and also present some actions that we are taking within the
22 NRR staff at this time and within I&E to address the issue.

23 As I discussed last Tuesday, Unit-3 is currently
24 down, in shutdown phase, and is undergoing an 84-11 inspection
25 to do a brief history of the IGSCC problem. As you may

1 recall, there are several I&E Bulletins on IGSCC, 82-03 and
2 then 83-02. Based on the results and findings of those
3 bulletins, the Staff was -- there was a heightened interest in
4 the crack phenomenon on BWRs. Back in 1984, we came out with
5 a generic letter describing and telling Licensees essentially
6 that we were interested now in a reinspection phase, but we
7 wanted them to go during each shutdown and do another
8 inspection program. We set out guidelines of what we
9 considered to be an adequate inspection program. That's
10 currently what Unit-3 is undergoing.

11 Last month, we started to get some of the results of
12 this program. As my second bullet indicates, we are seeing
13 numerous cracks. I guess, at this point yesterday, we
14 checked, since the program is still going on, that we are
15 talking on the order of 27 or 28 valves that have been
16 determined to have cracks.

17 I mentioned here the GE SMART system.

18 MR. SHEWMON: Did you say valves? You don't mean
19 valves, do you?

20 MR. GEARS: Welds. Excuse me. Cracks on welds. 28
21 welds have crack indications.

22 MR. OKRENT: Maybe if they looked at the valves,
23 they would find cracks.

24 MR. SHEWMON: If they could look at them, they
25 would.

1 MR. GEARS: The GE SMART system is mentioned here in
2 passing, because apparently it's the first time it's being
3 utilized. It's an automated system that is being utilized to
4 the fullest extent at a BWR inspection program.

5 MR. SHEWMON: Do you know what is "smart" or
6 different about that one? It's a tricky name.

7 MR. GEARS: I guess I can talk a little bit about
8 the system in a general fashion. I think there's currently
9 several automated systems out in the field. The GE system, I
10 guess the main characteristics, like most automated systems,
11 is essentially it allows the inspectors to sit in an area of
12 reduced radiation and gives them a time, a more relaxed time
13 period to actually look for cracks, and in that case the
14 meaning of "automated" here means that the transducers can be
15 controlled by the inspectors and in a fairly safe area.

16 MR. SHEWMON: Does that mean they also record the
17 signal?

18 MR. GEARS: They are all recorded on all sorts of
19 taping, a computerized video tape system, and go back over and
20 over again.

21 This particular system and its operators have gone
22 through the EPRI Center for certification and have passed.
23 There are, as I say, from my understanding, other automated
24 systems out there, but this is the first one that we know of
25 that has gone through a fairly rigorous use. I think

1 something up towards 75 percent of the welds at Peach Bottom
2 have been looked at first by the system.

3 A little bit more about the way they use the system
4 is, as I say, they try to take a first look with the automated
5 system. If indications are seen, they have two onsite,
6 independent NDE teams, Southwest and General Electric, who go
7 back and do manual confirmation.

8 As far as we know today, the confirmation has been
9 100 percent manually what the system has been showing. The
10 significance is, I guess, highlighted in Bullet 3, not that
11 we're just seeing cracks, but that the cracks apparently are
12 on welds that were originally called in 1983 to be clean or
13 at least were reported to be clean.

14 We have some additional data that the Licensee has
15 provided, based on 1983, which provides a comparison of the
16 '83 data with the '85 data.

17 Most of these welds have what is called -- back in
18 1983, it was called geometry or root geometry, and therefore
19 in 1983, based on those indications, they were considered to
20 be crack-free.

21 One of the cracks -- well, actually as of yesterday,
22 we understand there is more than one, but we're talking
23 perhaps two or three of the cracks are fairly significant in
24 terms of length, what we would call 360-degree
25 circumferential, and this one here is the deepest one so far

1 of that size. It's upwards of 55 percent through-wall.

2 Most of these cracks have been discovered on welds
3 that had received IHSI induction heat stress improvement, not
4 all, but most of them.

5 MR. MOELLER: Could you refresh me on what is the
6 rate of growth of such a crack? I mean, if you waited another
7 month or two months or a year, would it be 65 percent? When
8 was it 25 percent?

9 MR. GEARS: I'm not sure if I could handle that. I
10 can give you an indication. There is a fair amount, as you
11 all would know, of the 55 percent -- fair amount of error in
12 that, anyway, and how good we really know or how well we know
13 these cracks, even in terms of sizing them, once we see that
14 the error band is still fairly high.

15 MR. MOELLER: Roughly when was the weld done that
16 has now grown to this depth?

17 MR. GEARS: When was the weld first laid on this?
18 Well, this plant is ten years old, so I would say it's
19 approximately ten years old.

20 MR. MOELLER: Thank you.

21 MR. GEARS: And I would say that what we're saying
22 is, that crack was probably there back in 1983 but was not
23 seen, and therefore was not sized. So I guess there's no
24 indication at this point --

25 MR. EBERSOLE: Why do you say '83, when it might be

1 five years earlier?

2 MR. GEARS: That could be; yes, right. That's the
3 first time any of these welds went through such a rigorous
4 inspection. It could have obviously been earlier.

5 MR. OKRENT: Do you have a physical reason for
6 discarding the possibility that it grew over a two-year
7 period?

8 MR. GEARS: Do we have good evidence that it didn't
9 grow over two years? Maybe I'll let Warren Hazleton answer
10 that.

11 MR. HAZLETON: You obviously realize you're asking
12 sort of a complex problem, but let me try to cover it.

13 In the case of most of the cracks that have been
14 found, the weld had been given the IHSI treatment, and for
15 most of the cracks, small cracks, shallow cracks, we would
16 expect that the IHSI treatment would prevent any further
17 growth or initiation.

18 The only question that remains for these deep ones
19 and the IHSI treatment, although it puts the inside of the
20 pipe in compression, the outside of the pipe is in tension,
21 and somewhere the stress goes through a zero somewhere around
22 the middle. So if you have a deep crack, the IHSI process
23 could conceivably make the crack go faster than it would have
24 without it.

25 This is the main concern about the depth of the

1 cracks and the IHSI treatment. So I think in most of these
2 cases, we are fairly confident that the cracks were there in
3 '83 and were just miscalled. They were called geometry and
4 not cracks, which is the main problem with the inspection.

5 The other aspect --

6 MR. OKRENT: Excuse me. What I'm getting at is, I
7 am a little interested in trying to see whether, by following
8 what I will call the obvious interpretation -- namely, "We
9 missed it before" -- we could be leading ourselves into
10 missing something.

11 MR. HAZLETON: Yes. You interrupted me.

12 Remember, I said that you can have a problem with
13 deep cracks and IHSI.

14 The other thing that is of importance that I was
15 going to mention is, this particular run of pipe had at least
16 several -- I don't remember exactly -- probably at least two
17 full structural overlays on them. This is in the RHI system
18 that has high thermally-induced stresses, and we recognize the
19 fact that when you have abnormally high stresses, it wipes
20 out, if you will, a good IHSI. So we are not assuming that
21 this crack was present in the same configuration last time; we
22 are looking at the possibility that in some of these cases the
23 cracks have grown since 1983.

24 MR. SHEWMON: Dave, may I ask one question for
25 clarification?

1 You said that there had been a couple of overlays on
2 one of these. Is that the one that 360 degrees or a couple of
3 repairs?

4 MR. HAZLETON: There have been overlays on other
5 welds using the same pipe run. This one was said to be
6 crack-free in '83, so it had no overlay.

7 MR. SHEWMON: When they put an overlay on, it
8 shrinks the pipe?

9 MR. HAZLETON: Then puts higher stresses on the
10 adjacent --

11 MR. SHEWMON: And tensile stresses. It will tend to
12 drive the cracks.

13 MR. HAZLETON: Yes, sir.

14 This is, I might say, one of our main concerns about
15 continuing to operate, quote, "with overlays." It isn't
16 necessarily the overlay growth we're worried about; it's some
17 of the other welds that have had additional stresses put on
18 them.

19 MR. OKRENT: Let's see, now. I'm trying to
20 understand a broader Staff position. Is it the Staff's
21 position that you will always have leak before break, so even
22 though you have this rather frequent incidence of 360 degree
23 cracks quite a way through the wall, it is not a significant
24 effect with regard to risk to the plant or public health --
25 risk to public health and safety? They may be different

1 answers. Or that the existence of such cracks, in fact, does
2 change your perception of the risk, and you might tell me why.

3 I really don't know which of those two positions the
4 Staff -- or maybe some third position -- holds, given this
5 history of quite a few, what I would call major cracks.

6 MR. HAZLETON: Well, you ask a very big question.
7 Let me attack one part of it.

8 We are oversimplifying the situation here when we
9 are describing the crack. The crack is sort of 360-degree,
10 intermittent with some areas very shallow and other areas
11 deeper, with some spots very deep, like 55 percent. But
12 that's just a spot, what we talk about as cusps.

13 And the feeling has been that whatever local stress
14 situation or other causes, the cusp is going to cause it to go
15 through the wall at that point first and cause a leak.

16 Now one can -- you know, we can discuss this
17 situation all day, but we certainly don't like deep cracks,
18 and we certainly don't like deep cracks that have been given
19 an IHSI treatment, because it has a better propensity for
20 going through fast.

21 MR. OKRENT: I don't think you answered the basic
22 question, which is: Do these cracks and their frequency --
23 does this represent, in your opinion, some incremental
24 increase in risk by posing some increased likelihood of a
25 challenge under one or another circumstance? Or do you think

1 that they represent a very little increment in risk, if any?

2 MR. HAZLETON: I thought I touched on that, but
3 let's --

4 MR. OKRENT: I'd like you to be more specific and
5 not hint.

6 MR. HAZLETON: Okay, I'll be specific.

7 What we are talking about here is not specifically
8 new nor unexpected. That is, our attitude has been that the
9 standard residual stress pattern in the weld, plus the
10 standard stresses on the welds, are not likely to cause any
11 problem. We think they are going to leak locally.

12 We always have been concerned about the possibility
13 of cracks going through -- deep cracks in IHSI welds. So I
14 don't see that it represents any different policy. We have
15 recognized this as a possibility, and, of course, that is one
16 reason why we keep harping on doing a good inspection.

17 MR. OKRENT: I'm sorry. You know, I still don't
18 have an answer, and I think it's an important question, and I
19 would like to get an answer from the Staff, if not today, in
20 the not too distant future.

21 We have been having a record of finding major cracks
22 of BWR piping, large piping, over a period of years. Now it's
23 not necessarily obvious to me that inspecting and finding them
24 is adequate for protection of the public health and safety, if
25 there is some significantly increased chance of medium or

1 large-sized LOCA, which will pose a challenge that so far has
2 been answered only on paper and whose ramifications we don't
3 necessarily know, if, as in many other events, there are
4 associated other failures by chance or whatever.

5 I, for one -- I must say that I am less convinced
6 than most of your Pipe Review Group seems to be, that pipes
7 having these big cracks have almost the same chance of having
8 a medium or large-sized LOCA, meaning 10 to the -10 per year
9 or whatever it is people calculate.

10 I don't believe it. I would like to know what the
11 Staff things.

12 MR. HAZLETON: I am not -- clearly, I am not here
13 prepared to talk about the NRC policy on this.

14 MR. WARD: Okay. That's probably a question, a good
15 question in this session, you didn't come really equipped to
16 deal with this.

17 Paul, let me ask you, do you think that this recent
18 operating experience indicates the need -- is there something
19 new here that you think your subcommittee should look into?

20 MR. SHEWMON: I don't think our subcommittee could
21 come up with any probability numbers that Dr. Okrent would
22 believe, any more than the ones that we spent several million
23 dollars to get out of LLL.

24 MR. HAZLETON: I could discuss a little further what
25 we have been doing about this. This particular situation of

1 finding cracks on reinspection, that were apparently missed
2 during the previous inspection, is not new. We have been
3 finding this ever since early this spring, and as a matter of
4 fact, in -- I think it was June when we had a meeting down at
5 the NDE Center on inspection of overlays, I particularly
6 discussed this situation with the ELRI people. I thought we
7 needed a requalification program for the inspectors to make
8 sure, at least as sure as we could, that people knew what they
9 were doing out there, because we were seeing too many cases
10 where they had been missed previously.

11 And as a matter of fact, we then in a letter, August
12 1st to Georgia Power, we told them that we would expect that
13 they should requalify the people going to do the inspection,
14 perhaps one that is going for the third cycle after the first
15 one, and we do have cooperation from the Owners Group. We
16 have a requalification program going out. We are doing
17 something about it. Whether it's enough or not, I can't say.

18 MR. WARD: Let me ask Paul now to finish his
19 thought.

20 MR. SHEWMON: There have also been cases of
21 overcalls, which one hears on odd months, this being an even
22 month, or the other way around.

23 Is there any way you have of discerning one from the
24 other, or do you see any common threads on why sometimes
25 somebody goes back in and finds that there were one-third or

1 half of what they thought were cracks last time aren't cracks
2 this time?

3 MR. HAZLETON: No. We have asked that question
4 innumerable times.

5 MR. SHEWMON: You haven't got an answer, then?

6 MR. HAZLETON: That's right.

7 MR. SHEWMON: One other thing on this so-called
8 SMART system. Do they have in that any kind of signal process
9 particularly?

10 MR. HAZLETON: Yes. There's some signal
11 processing. I'm not familiar with it in detail, but it does
12 make a nice picture of the thing. It gives a better call --
13 it gives a picture where the operator do a better job with
14 signal recognition, so he can differentiate better.

15 MR. SHEWMON: Okay. Now, as well as people not
16 knowing how to do these things, there is a question of
17 whether people that know how, but still would rather do it
18 their own way.

19 MR. HAZLETON: Yes, sir.

20 MR. SHEWMON: Presumably the machine gives you less
21 of that problem; is that right?

22 MR. HAZLETON: Yes, that is right.

23 MR. SHEWMON: Or the SMART system.

24 MR. HAZLETON: This is another thing that we have
25 been trying to emphasize, that people can go down to the NDE

1 Center and learn how to do it. But whether or not they really
2 do it when they get out in the field is another question. We
3 try to monitor that with our Region people, but they just
4 can't look at everybody and look at all the details.

5 But we are trying to emphasize to the owners that
6 it's their responsibility to see that the people do do the job
7 that they're trained to do.

8 MR. SHEWMON: To come back to your part, these
9 things are not -- I guess, let me tell you why I'm somewhat
10 more comfortable than you are, though I don't like what's
11 going on.

12 Partly, the cracks are not uniform round, as he has
13 said. So presumably it would go through at some place before
14 others. And then you get back to the usual safety systems
15 which you've got there, since this is a DBA. And I appreciate
16 that you're not comfortable getting close to challenging one
17 of your safety systems, but that, I think, is where we are.

18 Presumably they are better now than they were in
19 '83, not a lot better maybe, but some better, and hopefully
20 they will get most of these things isolated before they come
21 back.

22 One other thing that the Staff isn't here to talk
23 about today, but some utilities are going to come back in and
24 say, "We would like to leave these cracked pipes with overlays
25 and their plus-hydrogen treatment which seems to stop the

1 cracks from growing. And that would be interesting to listen
2 to also.

3 MR. GEARS: I want to add to that, that we already
4 have one utility that has added to the life of the plant --

5 MR. SHEWMON: I've talked to the Licensing people
6 there, and they say it hasn't been docketed. They just came
7 in and talked to the Staff. I find it a little slippery
8 myself.

9 MR. GEARS: I stand corrected, then.

10 MR. OKRENT: I'm concerned that there seems to be
11 the possibility of a kind of mind set in the Staff, maybe
12 broader, that you can't have a LOCA. You know, once you're --
13 if that is your initial approach, then you say, "Well, if
14 cracks are occurring, we have to find them," but, you know,
15 you're not particularly alarmed, and, in fact, you may or may
16 not go in to see why you got one where you shouldn't have
17 gotten one. And in particular, you won't go back and evaluate
18 the basic, if you will, premise that we can't have a LOCA and,
19 in fact, factor the possibility of a LOCA in with a range of
20 other operating experience that we have, where, in fact, you
21 have multiple things sitting in one event all the time.

22 So despite the supposed design-basis accident aspect
23 and so forth, there may be surprises. I have the sensation
24 that there is too much of a feeling of being at ease with a
25 continuing history of what I call major cracks.

1 They vary, of course. Some have been much worse
2 than this, as we know.

3 In my opinion, either the ACRS should have a
4 conscious review of this, or they ought to ask the Staff for a
5 White Paper in detail which tells us why what the Staff has
6 been doing and is doing is adequate for protecting the public
7 health and safety. I think the situation should not just go
8 on as it has been.

9 MR. SHEWMON: What is the status -- let me ask the
10 Staff -- what is the status of NUREG-0313, Rev. 3 or whatever,
11 that is supposed to address this question.

12 MR. WARD: A very short answer, please.

13 MR. HAZLETON: A very short answer is that it's in
14 for final typo corrections. I expect -- did expect that this
15 week I would prepare a memo from Denton --

16 MR. WARD: That's your answer.

17 MR. SHEWMON: This is part of the Pipe Study Group
18 that deals with stress corrosion cracking and the report of
19 the sort that Professor Okrent is looking for. Whether it
20 will have the quality or not he wants, I don't know. We'll
21 soon know.

22 MR. WARD: Jesse, I would suggest we have aired this
23 enough.

24 MR. EBERSOLE: We're coming to the end of our
25 allotted time in two minutes.

1 MR. WARD: Why don't we skip the last item.

2 MR. EBERSOLE: The last item was for Bill Kerr, and
3 it's a matter of discipline versus real significance.

4 I did omit one thing. Did we have a company
5 representative from --

6 MR. ROSSI: Maine Yankee. I thought somebody from
7 Maine wanted to say something.

8 MR. EBERSOLE: If they are here and want to say what
9 they want to do about this, fine. Otherwise, we're through.

10 MR. BEARD: Jesse, they decided not to come.

11 MR. EBERSOLE: Good, I'm glad to hear it.

12 MR. REED: I'd like to make just a quick protest
13 statement, that I do not think the Fermi event should be
14 classified as an abnormal occurrence. I'd like that to be in
15 the record.

16 MR. EBERSOLE: Fine.

17 MR. WARD: Thank you. Let's take a ten-minute
18 break, and we will come back with the GESSAR topic.

19 [Brief recess.]

20 MR. WARD: The next topic of business is the GESSAR
21 II review, and I ask Dr. Okrent to take over the meeting.

22 MR. OKRENT: Let me first note that on Saturday, I
23 expect to have some kind of a first draft letter for the
24 committee to cogitate over. My best guess is that what we can
25 do then is to have a serious discussion of a range of issues,

1 some broad, some specific, and maybe if we're lucky, gain an
2 idea of the direction in which the next draft should go, and
3 maybe we will ascertain that there are some issues where the
4 committee will want to hear a little more and so forth.

5 We held a subcommittee meeting yesterday which
6 covered a range of topics, and in considerable part, based on
7 what seemed to be well-covered or what seemed to perhaps have
8 some questions, as well as from the point of view of bringing
9 to mind for the committee certain but not all of the matters
10 that it will have to consider in the overall review of the
11 case.

12 There is an agenda which has been handed out, and we
13 will go through it in a minute.

14 Let me just make one or two observations. One topic
15 that we did discuss for a little bit at the subcommittee
16 meeting, which I did not put on today's agenda, but which I
17 think is something that warrants calling to the attention of
18 the full committee, is that the reactor vessel for a BWR has a
19 design such that the control rods commence with the bottom
20 head, and that -- a lot of them, like 100 -- and that, plus
21 the general incore structural arrangement, makes it
22 impractical, I believe -- at least I think that's the state of
23 the situation -- to inspect certain of the welds at the bottom
24 head, and I believe that it is not the custom to inspect the
25 region between these many penetrations for control rods.

1 Now this is not -- it is not a welded region, but
2 it's sort of a Swiss cheese kind of affair. And although to
3 my knowledge, no one has observed any problem in that area, we
4 are talking about very low probabilities of vessel failure in
5 all of the PRAs and so forth. Certain modes of vessel failure
6 at the bottom of this vessel could lead to releases which fly
7 in the face of the trends, you know, that people talk about in
8 source term considerations.

9 So it is a question that in some way I think the
10 committee will have a need to think about, but we did not put
11 it on this agenda. It looked like there were enough other
12 topics.

13 MR. MARK: Just for my edification, there are holes
14 through the bottom to accommodate the control rods. In what
15 rough kind of spacing and number do those holes exist? Are
16 they a foot apart, or is it closer than that together?

17 MR. OKRENT: You mean from center to center?

18 MR. MARK: From hole to hole.

19 MR. REED: It's at least a foot.

20 MR. MARK: So it's a very solid, interposing piece
21 between holes. The holes aren't close enough together to
22 interact.

23 MR. EBERSOLE: They're mighty close. Well, GE can
24 say that. What's the spacing between the rods?

25 MR. VILLA: Six inches on the housing.

1 MR. EBERSOLE: The housing is six inches?

2 MR. WARD: Let's see, could you give your name and
3 use the microphone?

4 MR. VILLA: Rudy Villa, General Electric.

5 I don't have the exact number, but each of the
6 bundles is about four and a half inches in dimension square,
7 and there are at least four bundles in each area, and the
8 blade covers at least four bundles. So I think we'd be
9 talking about at least an eight-inch diameter for each of the
10 housings. There are 205 -- at least over 200 -- that
11 penetrate the bottom of the vessel

12 So I think it's probably at least a foot, center to
13 center, of these, and these are welded directly into the
14 vessel, on the vessel plate on fabrication.

15 MR. MARK: And those welds are looked at when
16 performed, but you can't get to them later.

17 MR. VILLA: That's correct.

18 MR. MARK: Thank you.

19 MR. MICHELSON: There's also a two-inch drain line
20 at the very bottom of the vessel which you can look at before,
21 but I don't think you can look at it later, and that is a far
22 bigger hole, of course, than the rods.

23 MR. OKRENT: In any event, I'm mentioning this. I
24 thought the agenda was already so full that --

25 MR. MARK: This is not unique to GESSAR. This is

1 the way things have been built from the beginning.

2 MR OKRENT: The way they are is a question, really.

3 Let me, if I can, just read a set of thoughts I sort
4 of jotted down to, in a sense, ask myself, what are things one
5 should think about in the process of trying to arrive
6 somewhere in this review? So I will just read what are
7 questions here, and it's not intended to be a complete list or
8 in any order of priority.

9 What is an FDA? What commitment is the NRC making
10 when it issues one?

11 What commitments would it be making if it approves
12 GESSAR II?

13 How much detailed information should be provided by
14 the Applicant for an FDA?

15 What should be the level and the depth of the PRA
16 which is required? Should it treat uncertainties, as well as
17 the state-of-the-art permits?

18 What should the interface requirements with the
19 balance-of-plant be? How should they be specified, in view of
20 the fact that the PRA makes assumptions about balance-of-plant
21 performance?

22 What seismic fragility requirements should be
23 established or are established by the GESSAR PRA and by the
24 Staff review?

25 What other performance requirements for GESSAR II

1 systems are established by the PRA, if any?

2 What level of PRA evaluation and review should be
3 performed by the Staff, should have been accomplished by the
4 Staff, for it to accept an FDA, and should the Staff report
5 mean values of various important parameters which are
6 evaluated, as well as the state-of-the-art permits?

7 What should be the quantitative safety objectives
8 for future plants?

9 Is there some kind of containment criterion that a
10 future plant should meet, even though the Staff hasn't come
11 forth with a proposal?

12 Of course, how to deal in design for terrorists and
13 sabotage in future plants, we haven't talked about, and it's a
14 question I have to think on here.

15 How should one do cost/benefit analyses for possible
16 design improvements?

17 How does one assure defense-in-depth?

18 How does one assure that the frequency of challenge,
19 like the number of scrams and so forth, is acceptable?

20 How does one judge that the Staff resolution of USIs
21 and generic items is acceptable for GESSAR II? Is there some
22 criterion for judging? Are there what I will call design
23 matters that should be raised on GESSAR II as to future
24 plants, even though there are current designs which are being
25 accepted for the MARK III, for example, changes in the

1 hydraulic scram volumes or whatever?

2 And how does one assure that something like the
3 considerable number of open issues in the seismic safety area
4 will be handled appropriately, if you grant an FDA?

5 There are a range of such questions. I will just
6 mention a few.

7 There seems to be insufficient information on core
8 internals fragility, according to the Staff's expert panel on
9 seismic safety.

10 The Staff has identified the open question on
11 relay chatter.

12 There have been recommendations again by the Staff's
13 expert panel that one look for seismic systems interactions
14 -- that is, interactions between non-seismically designed
15 systems and systems important for safety and things like this.

16 Anyway, as I say, this is not a complete list, but
17 I'm just trying to bring out the kinds of questions that, as I
18 say, I ask myself when I try to evaluate, where are we in this
19 review, where am I in this review, and, in fact, you will see
20 that my first question is, in fact, the first topic on the
21 agenda.

22 We had quite a bit of discussion in the subcommittee
23 meeting yesterday, just what is an FDA, and what is specified,
24 and I'm not sure that the subcommittee felt that it quite knew
25 even was the Staff was defining as an FDA.

1 And then there is, perhaps, our image as to what the
2 details should be.

3 MR. SHEWMON: Do you feel you need answers to all
4 those before you can write a note that says that you think
5 this will or will not be a significant risk to the public,
6 whether here or wherever it is built?

7 MR. OKRENT: I am saying that these are questions
8 that certainly come into my mind as I try to think about how
9 do I prepare a possible committee report. And in some cases,
10 you raise a question, you think about it and say, "It seems to
11 be okay as the Staff has done it." In another case, you might
12 look at it and say, "At the present time, the Staff has not
13 tied it down sufficiently with what they propose to do or
14 whatever."

15 There will be a draft to look at, okay?

16 MR. MARK: I'm slightly puzzled on the matter of the
17 PRA. I can imagine doing something called a PRA on the part
18 of the plant that is included in GESSAR, but then almost
19 everything depends upon things not there, site-specific
20 earthquake level, whether it comes from the north or the east
21 or goes up and down or sideways, watertanks and everything
22 else.

23 So will there then have to be a subsequent PRA for
24 the plant that might get licensed, because the PRA on the
25 GESSAR II itself may tell one something, which certainly

1 doesn't tell one what one needs to know?

2 MR. OKRENT: Let me try to give a one or two-minute
3 answer to that.

4 In fact, the Staff is going to, in its own position,
5 require that there be a plant-specific PRA, at least to cover
6 those parts of the PRA that are not in the GESSAR design or
7 have to show that they have systems or components that meet
8 whatever GESSAR assumed in its PRA.

9 And in the seismic area, you will hear that there
10 will be a need for the utility referencing this FDA to show
11 that its fragilities match certain fragilities that have been
12 identified either by GE or the Staff or show that whatever
13 they have doesn't produce a significant change in risk. But
14 we don't have a definition of the word "significant."

15 The question, I think, is complicated by the fact
16 that you have part plans, and certainly it doesn't make it
17 easy for -- but it's most; it's part, but it's most -- for GE
18 to do a definitive PRA. But on the other hand, this is
19 supposed to be a final plan approval for GESSAR II itself, and
20 one can ask whether the state of the information, the state of
21 the PRA that was done for GESSAR II, is done to the level that
22 one thinks it should be for a final design approval, and again
23 whether the review has been done -- an evaluation has been
24 done to the level it should, because presumably performing
25 this PRA was not just a routine thing, intended to have no

1 impact, no significance in the licensing.

2 Presumably the purpose of doing the PRA was to
3 enable the Staff and the Applicant to get increased insight
4 into the nature of the plant, its strong and weaker points,
5 its risks, to enable the Applicant and the Staff to evaluate
6 possible improvements in the plant. And if the PRA is
7 inadequate for this purpose, then one has not, in a sense,
8 accomplished, it seems to me, the intent, as I understand it,
9 of the severe accident policy statement of the Commission.

10 So it's a complex matter, and that's why I put these
11 questions the way I did. I didn't give you any answers. I
12 want you to think on these kinds of things, and you will have
13 to judge for yourself in many of these -- it somewhat all
14 hinges on, what do we mean by and FDA and when are we willing
15 to say, "Well, we'll buy this," and not agree that it has to
16 be a backfit to change and so forth.

17 I would propose we begin with the agenda,
18 Mr. Chairman. I notice that at the end of this period we
19 move into some committee business and I am assuming that we
20 might run 30 minutes.

21 MR. WARD: I hope not too late because we do have a
22 full schedule. We are already half an hour into it.

23 MR. OKRENT: We're a half an hour into it. I only
24 left 15 minutes at the end for others.

25 Okay. The NRC is up for Agenda Item 1.

1 MR. SCALETTI: Good morning, my name is Dino
2 Scaletti from the NRC Staff. With regard to Agend Item 1,
3 Mr. Michelson had asked to put some words on paper so that
4 some questions could be generated. I made an attempt at that
5 to cover basically what an FDA is. I don't know whether you
6 want to generally discuss FDA's or whether you wanted to talk
7 about this recent issuance of Amendment 1 to the GESSAR II
8 FDA. So I will endeavor to answer any questions you have
9 based upon the information that I have given you now.

10 MR. OKRENT: Mr. Michelson?

11 MR. MICHELSON: Since I asked for the statement, let
12 me say that I think this is exactly what I think an FDA will
13 be, but I need a couple of clarifications.

14 First of all, if I do not find a document referenced
15 in any of these four items that you listed as the scope of the
16 FDA, I assume that document is not a part of the FDA approval.

17 MR. SCALETTI: If it's not listed, it's not found in
18 the context of the application, --

19 MR. MICHELSON: By application you mean these four
20 documents now?

21 MR. SCALETTI: Those are just the major four --

22 MR. MICHELSON: Wait a minute. If I understand your
23 statement correctly, if it doesn't appear in GESSAR II or its
24 amendments or the SER or its amendments, then it's not a part
25 of the FDA. Is that correct?

1 MR. SCALETTI: The application probably entails more
2 of that. There's other information associated with the
3 application.

4 MR. MICHELSON: It's the other information that has
5 given us trouble from day one.

6 MR. SCALETTI: This is the technical information I'm
7 alluding to here. This is the information I assume you're
8 concerned about.

9 MR. MICHELSON: I'd like to know to what extent your
10 receipt of technical information constitutes acceptance, and
11 that was the issue from day one. Your statement here I agree
12 with.

13 MR. SCALETTI: Our process for final design approval
14 parallels that of a receipt of an operating license
15 application. The information is required by that information
16 identified in 50.34(b), the same level of information.
17 Granted, not as much information because with regard to GESSAR
18 it doesn't include the whole plant.

19 MR. MICHELSON: Let me correct the statement you
20 gave us, then, because I don't think it's correct.

21 The statement you gave us has to include in the
22 second paragraph after the first sentence that the ending must
23 include "and such other information as the NRC might have
24 received."

25 MR. SCALETTI: That's all part of the application.

1 MR. MICHELSON: Wait a minute now, read your words
2 carefully. "It must be presented..." -- that means to me it
3 must be in GESSAR II or its amendments. That's the only way
4 you present material.

5 MR. SCALETTI: Clearly, I agree.

6 MR. MICHELSON: If it's received by you but not
7 referenced in GESSAR II, not referenced in its amendments nor
8 mentioned in your SER, then that document, to my way of seeing
9 it, is outside of the FDA.

10 MR. SCALETTI: I tend to agree with you, yes.

11 MR. MICHELSON: Then my clarification is correct
12 that it must be in GESSAR II, stated explicitly, or its
13 amendments or your SER or their amendments.

14 So if you receive, for instance, an interface
15 document which you did not mention anywhere and GESSAR didn't
16 mention anywhere, that interface document is not a part of the
17 FDA approval. Is that correct?

18 MR. SCALETTI: That would be my understanding of it,
19 yes.

20 MR. MICHELSON: So we're in pretty good shape, then,
21 because all I have to do is read these four documents and then
22 I know the scope of the FDA.

23 The next question is having mentioned the document
24 in one of these four locations, if the document revision
25 hasn't been mentioned, only the document number, how do I

1 handle the future revisions of that document, as far as the
2 FDA approval is concerned?

3 MR. SCALETTI: The document revision, if it had been
4 revised, should be identified.

5 MR. MICHELSON: If for some reason -- and generally,
6 it's not referenced by revision -- but if it isn't referenced
7 by revision, then how do you handle the problem? You going to
8 go back and correct these documents and do that?

9 MR. SCALETTI: If a referencing document is not
10 handled -- does not include a revision number and it has been
11 revised, only if the review took place utilizing the current
12 revision to the document, if the application was reviewed
13 against an earlier revision or the original document, it still
14 may be an acceptable document.

15 MR. MICHELSON: My problem is when I read a
16 reference and find that you've used a certain interface
17 document but didn't tell me which revision, then I have a
18 problem over which revision should I look at and which one is
19 the extent of the FDA approval. It's a kind of sloppy
20 business which QA people would not normally allow, you know.

21 MR. SCALETTI: I guess I agree. The revision to the
22 document should be identified if it has been reviewed

23 Mr. Rosenthal would like to inject a comment.

24 MR. ROSENTHAL: Just a point. Chapter 1.7 of the
25 FSAR is a list of drawings. Those drawings are shown, and I

1 will hand you the SAR in a moment to include drawing number
2 and Rev number. Those are delivered in the equivalent of a
3 truck to the NRC, and those are QA drawings.

4 MR. MICHELSON: The listing --

5 MR. ROSENTHAL: So there are the rev numbers right
6 in the SAR.

7 MR. MICHELSON: Our problem hasn't been with the
8 drawings in the SAR; it's been with all the things that keep
9 coming up at the meetings about interface documents, component
10 specifications and so forth, and they say, well, it's in the
11 component spec. Well, my question is: was the component spec
12 a part of the FDA approval? And in order to be so, it must be
13 listed in one of the four documents that you have cited, and I
14 don't find it listed in there. I don't find the document in
15 there. Then, what do I assume? I assume that document really
16 isn't a part of your FDA approval because it's not listed
17 anywhere.

18 It's kind of sloppy. You know, I find this to be
19 not an occasional experience but rather a prevalent one.

20 MR. SCALETTI: To be a part of the application it
21 certainly has to be identified.

22 MR. MICHELSON: I think we established what I was
23 worried about. If I don't find it in the GESSAR or in its
24 amendments or your SER and its amendments, then it isn't a
25 part of the FDA. If I find it in there but not referenced by

1 revision, then hopefully somebody could tell me what revision
2 number to look at. But that is just a little bit of
3 sloppiness, but at least it has to be in these documents, and
4 I think you have agreed that it has to be in one of these four
5 categories.

6 MR. OKRENT: It seems to me if they don't tell you
7 the revision number it's really an incomplete statement.

8 MR. MICHELSON: It's unacceptable. From a QA
9 viewpoint this is unacceptable practice, so that the NRC will
10 chastise the utility for it.

11 MR. SCALETTI: I must say we have, I believe, a
12 rather competent editorial staff and they do pick up on these
13 items. I do agree that our tech reviewers sometimes tend to
14 be a little easygoing with regard to referencing documents,
15 but the endeavor to try to correct all these mistakes.

16 Certainly, there are some that get through without
17 being corrected. Maybe the QA is not quite what it should be.

18 MR. MICHELSON: I understand the principle now at
19 least. Until today I hadn't really understood what your scope
20 was, and I think that is now nailed down.

21 I would like to ask, is this GE's understanding of
22 how it's to be handled as well?

23 MR. SHERWOOD: That's correct.

24 MR. MICHELSON: Thank you.

25 MR. OKRENT: Are there any questions members wish to

1 ask about what the definition or meaning of an FDA is and so
2 forth?

3 [No response.]

4 I guess not. Then let's go on to the second agenda
5 item where we asked the Staff and GE to add such comments as
6 it thinks are relevant to review the major results and
7 conclusions from their evaluation of the PRA, their
8 qualifications with regard to the PRA and what their estimates
9 are on the meaning core melt frequency and what their
10 qualifications are on that definition.

11 MR. WARD: Are we all set? We need to kind of move
12 along with this.

13 MR. SCALETTI: Mr. Rubin from the Staff.

14 MR. RUBIN: My name is Mark Rubin from Realiability
15 Risk Assessment Branch. Just as a preface to Mr. Rosenthal's
16 presentation I will repeat what I said yesterday at the
17 subcommittee meeting that the internal event core melt
18 frequency numbers that are presented in the Staff's SER are
19 mean estimates. The seismic core melt estimates are composed
20 partially of mean values in that a mean component fragility
21 curve was assembled by Brookhaven National Laboratory and it
22 was combined with an assumed mean hazard function.

23 The reason the end result is not truly a mean value
24 is that we did not know what the site hazard function would
25 be, nor indeed any distribution certainly for that function.

1 Therefore, we would not characterize the seismic core melt
2 frequency really as a mean value. It was treated as that
3 numerically, and if our assumption of the site hazard function
4 is indeed a mean, then obviously the number would be a mean
5 result.

6 For the total core melt frequency numbers we
7 combined the internal event mean numbers with what was
8 basically a numerical estimate of the seismic to get a point
9 estimate or really a range of possible core melt
10 contributions, and in our sensitivity analysis in SSER No. 4
11 we also presented a range of values. The numbers you will see
12 in Mr. Rosenthal's presentation of core melt.

13 That really concludes my comments. The numbers you
14 see in Mr. Rosenthal's presentation on consequences were based
15 on the numerical estimates, the point estimates for total core
16 melt.

17 MR. SCALETTI: Mr. Rosenthal has some material on
18 Items 2 and 4, 5 and 6. Would you like him to proceed and
19 discuss all of those items at one time? It would probably be
20 more expeditious.

21 MR. OKRENT: No, I would prefer that we stay with
22 the agenda.

23 MR. ROSENTHAL: On Item 2 -- my name is Jack
24 Rosenthal, I'm in the Reactor Systems Branch, Division of
25 Systems Integration.

1 Our risk estimates are based on mean values of core
2 melt frequency binned into consequence predictions.
3 Consequence predictions are really a range of values for which
4 we don't have distributions. At least, I had thought it
5 appropriate that we explain that and how we got there, should
6 you desire.

7 MR. OKRENT: We asked the Staff to give a summary
8 presentation in this area and tell us what their major results
9 and conclusions were and where they have qualifications.

10 The committee has heard various parts of the picture
11 over many months, and I thought it would be helpful if you
12 could give them what you feel to be the major results and soft
13 spots in a sort of a capsule picture.

14 MR. SCALETTI: Jack, there is some GE proprietary
15 information in one of these slides. Can we just delete that
16 slide, or we'll have to close the meeting.

17 MR. ROSENTHAL: When we get to it, depending on the
18 conversation, why don't we just take it out.

19 MR. WARD: Try to delete it if you can.

20 [Slide.]

21 MR. ROSENTHAL: We have looked at a range of
22 containment failure modes, and associated with that range of
23 containment failure modes, is a range of possible ways in
24 which fission products can be dispersed from the core.

25 I would like to point out that unlike the large dry

1 work that was done in past years the GESSAR effort was very
2 much a source term intense effort.

3 [Slide.]

4 When we did the source term work, -- and the
5 divisions were made almost two years --

6 MR. WARD: That's a proprietary slide, Jack. If you
7 take it off you can refer to it.

8 MR. ROSENTHAL: We had, for several sequences,
9 release fractions predicted in Grand Gulf predicted by IDCOR,
10 predicted by GESSAR which are proprietary. The Staff spent
11 many hours with Brookhaven. It is a joint Staff/Brookhaven
12 consultant decision on an attempt to pin down a range of what
13 those source terms might be. And we took the releases apart
14 and considered primary system retention, pool scrubbing,
15 deposition settling in the containment, containment failure
16 times in order to derive those source terms. There was just
17 no way of constructing a mean distribution for these values.
18 We thought that high and low values capsuled the
19 essence.

20 MR. REMICK: Excuse me, Jack, I'm sorry to interrupt
21 but I don't understand what those units are.

22 MR. ROSENTHAL: A fraction of the original core
23 inventory released to the environment for a transient event
24 with late containment failure with pool scrubbing.

25 MR. REMICK: Thank you.

1 [Slide.]

2 MR. ROSENTHAL: The ASTPO code suite looks something
3 like that --

4 MR. MOELLER: You said released to the environment,
5 not just to containment?

6 MR. ROSENTHAL: Released to the environment. We can
7 take that apart if you like.

8 But in any case, the ASTPO code suite was exercised.

9 [Slide.]

10 And here's a slide that compares our high and low
11 estimates of some time ago with what we would get in the
12 middle column with the ASTPO code suite. I am reluctant to
13 argue that the ASTPO code suite would represent a central
14 estimate. I'd rather make decisions based on high and low.

15 GE's numbers are typically -- in terms of
16 consequences -- two orders of magnitude lower than Staff's
17 numbers, IDCOR numbers, or like GE numbers or perhaps even
18 lower. Just for some perspective.

19 So let me repeat again. What we have done is we
20 have glued mean values on the front end core melt frequencies
21 somewhat with high end sensitivity studies of release
22 fractions in order to calculate person rem, which were in turn
23 used in cost-benefit analysis. At least relative to the ASTPO
24 code suite, I don't think our high range numbers are that much
25 higher than we get with mechanistic codes.

1 [Slide.]

2 I have to talk about modes of containment failure
3 for a moment, and then I can encapsulate this thing.
4 Calculations of long-term overpressurization of containment
5 occur in the range of 10 to 20 some-odd hours depending if you
6 believe INTER or CORCON.

7 [Slide.]

8 MR. ROSENTHAL: Calculations of the burn of 3000
9 pounds of hydrogen in Grand Gulf over an hour show that you
10 won't overpressurize containment. That is the peak at 40.
11 The rest of the slope is due to core-concrete interaction,
12 eventually overpressurizing containment.

13 [Slide.]

14 We saw high temperatures if you believe MARCH for
15 the containment atmosphere, and we looked at the effect of
16 those high temperatures on seals, and we don't think -- the
17 most critical seal is the wetwell, drywell hatch seal, which
18 we don't think will fail. That still leaves open the question
19 of detonations and deflagrations failing containment and your
20 own views of the credibility with which we do hydrogen
21 calculations.

22 [Slide.]

23 Given that, we can summarize somewhat flagrantly --
24 we can boil down a dozen containment event trees, take several
25 man years of work, condense it down to one slide. Please

1 don't wince at some of the assumptions.

2 [Slide.]

3 For instance, station blackout. In GESSAR PRA,
4 there is a specific containment event tree for events prior to
5 vessel failure, another one after vessel failure. We just
6 folded them together. The picture we have here is of a plant
7 with LOCAs being some fraction less than one percent of the
8 total ways of getting the core melt. Dominated by station
9 blackout, about 79 percent of the core melt frequency.
10 Transients other than blackout are another few percent, and
11 you can use blackout almost as a surrogate for them.

12 Loss of containment heat removal, which was a far
13 more dominant event in the RSS, is now about 10 percent. That
14 includes recovery being taken into account there, and ATWS
15 about 8 percent. On the MARK Is and IIs, ATWS is important to
16 risk. It's a dominant sequence in terms of consequences,
17 although there is a low probability.

18 On this layout of the plant we expect to get a fair
19 amount of pool scrubbing, and hence the consequences of ATWS
20 are far less than what we would have predicted on an older
21 plant.

22 MR. EBERSOLE: Would you make clear, if that was an
23 ATWS with the program, the mitigative response?

24 MR. ROSENTHAL: Yes. If you have the ATWS and you
25 follow the procedures, you will dump some place between 15 and

1 25 percent of core power into the pool, and 18 seems a popular
2 number, but that is going to switch around. You really have
3 to do detailed, space-time kinetics calculations to get a good
4 handle on that number, but it is clearly greater than the
5 decay heat removal capability from the pool to the ultimate
6 heat sink, which is in the range of 4 to 8 percent, so you
7 will overpressurize containment.

8 The great race here is can you put enough boron into
9 the primary system to shut down the reaction, bring the power
10 lower before you overpressurize containment.

11 MR. EBERSOLE: Did you include in here the
12 probabilistic aspects of doing that without washing it out and
13 so forth?

14 MR. ROSENTHAL: The washout wasn't considered. The
15 8 percent number here includes estimates of the reliability of
16 slip.

17 MR. WARD: Of the reliability of carrying out this
18 maneuver? Okay. What about the one percent from LOCA? How
19 sensitive is that to the assumption that is made about the
20 probability of a large break? I don't know what number you
21 are assuming for a large break failure, but what if it is
22 order of magnitude greater than whatever you presume? What
23 does that do to the one percent?

24 MR. ROSENTHAL: To capture the essence, let's assume
25 it's one percent. I'm sorry, it's ten percent. Okay.

1 [Slide.]

2 Let me just point out here that this was without
3 igniters, which was the original GESSAR proposal, so I have a
4 drywell failure due to hydrogen burns, a wetwell failure due
5 to hydrogen, deflagrations and detonations, late containment
6 failure, and early failure due to -- ATWS is an early failure
7 due to steam production, the TW sequence, or the two T-B3
8 sequences is a late failure due to steam production.

9 Now, let's look at the consequences of these events.

10 MR. MARK: I wanted to ask you about detonations.
11 You were pointing at an estimate made without igniters, but
12 there is no sense pointing at such an estimate as more.

13 MR. ROSENTHAL: GE has agreed to put igniters on
14 the plant. Staff has recommended, required that those
15 igniters be put on diverse power so that they would be
16 available in the event of a station blackout. You do that
17 because of the high probability of blackout. Now, the effect
18 of that is to take these one T-I2, one T-E3 releases. I2 is
19 an intermediate time failure of the drywell, and E3 is an
20 early failure of the wetwell, and you shift them into L3.

21 MR. MARK: Do you shift them or do you delete the
22 numbers?

23 MR. ROSENTHAL: Core melt frequency would be there,
24 yes, these are deleted, and now the probability of an L3 event
25 goes way up.

1 MR. MARK: Then is detonation any longer a thing
2 that deserves attention?

3 MR. ROSENTHAL: No.

4 Let's go back to that first --

5 MR. OKRENT: We are not so sure about the seismic
6 qualification of the igniters, so on your detonation question,
7 we want to keep one thing up --

8 [Slide.]

9 MR. ROSENTHAL: Now, why should one put igniters on
10 the plant? If you believe GE's risk estimates, it is hard
11 to make a cost-benefit argument. If you believe our
12 estimates, we still have some troubles making a
13 cost-beneficial argument. The reason to do it is to reduce
14 uncertainties.

15 For example, we have intermediate time failures of
16 containment due to hydrogen, one called quench, in which the
17 pool fails here, dumping the water into the debris bed and
18 quenching the core. Alternately, if the pool fails and the
19 debris dumps here, you don't quench the core. I personally
20 don't think we should bet on the failure given the
21 detonation. The way is to put on a system such as you don't
22 have to worry about it.

23 L3 failures of the wetwell are probable here. If
24 you believe in pool scrubbing and you don't believe in leaks
25 in bypass, then it's okay to blow up the wetwell, but if you

1 are concerned that you haven't properly closed on bypass or
2 the drywell, then you would like to preserve this integrity,
3 and what you are doing here is you buy time for agglomeration
4 of settling fission products in the pool.

5 You note that my plots of pressurization show 10 to
6 20 hours for agglomeration of settling the L3 sequence. What
7 you are doing is reducing the uncertainty in your estimates by
8 putting on the igniters, and that is the primary effect. It
9 makes the course of the accident more well known.

10 [Slide.]

11 Now let's get back to this slide for a moment. What
12 I am showing here is that you always fail containment. We had
13 trouble with that as a philosophic approach. Unlike other
14 PRAs where you typically will have a no-fail mode or a
15 basemat which tends to be relatively benign, here we don't
16 expect basemat failure. It's a real thick basemat. But we
17 are concerned in this sort of scenario due to either hydrogen
18 or overpressure you will fail the wetwell, and conceivably
19 another sequence is the drywell, depending on what you believe
20 about igniters. Hence, you always release all of the noble
21 gases.

22 What you have bought is good retention of iodine,
23 cesium and the heavier elements, but the price is paid in
24 terms of the nobles.

25 MR. OKRENT: This is an important point and one, I

1 think, which the committee will want to think on Saturday and
2 maybe future Saturdays. Is it appropriate for future reactors
3 to, according to the Staff, have containment design which has
4 a likely containment failure mode which has modest releases,
5 namely, the noble gases, but which has a very high likelihood
6 -- he said always -- let me say a high likelihood of failing
7 given a large-scale core melt.

8 One could in principle think of modifications to the
9 design which change this characteristic. I'm not saying it's
10 unacceptable; I'm saying it's something the committee should
11 think about consciously and decide is it okay or not okay.

12 MR. MOELLER: Let me ask a question on the previous
13 slide. If you total up the contribution of the various
14 events, and I realize it's not this precise, but it comes out
15 a little more than 97 percent. Is there anything of
16 importance, any event that is a major contributor to that
17 other 3 percent, 2 or 3 percent?

18 MR. ROSENTHAL: Event V for boiler has the potential
19 for being a bad release category. We can bin it into one
20 1-SB-E1, but I am reluctant to do that. In fact, we have some
21 mechanistic work under way to try to get a good handle on an
22 Event V rather than making untold pessimistic assumptions.
23 But if you have to do something now, you bin it into the
24 E1. When we get in the seismic area, for large seismic events
25 we can then introduce other failure modes. I am going to get

1 back to that.

2 [Slide.]

3 Now let me show you internal events as the
4 calculation is carried out to infinity, sample lots of
5 weathers, et cetera for the release fraction of the nature
6 that I showed you on the earlier slides. Bear in mind we may
7 define containment performance in terms of potential for
8 nuclides rather than failure of containment. We calculated
9 zero, essentially, early fatalities, few early injuries and
10 modest latent fatalities, modest latent fatalities, none,
11 zero.

12 There is an interesting perspective here. Let's say
13 that one would choose to compare the plant to the safety goal
14 and assume that the core melt frequency was one per 40 years.
15 Then would the plant meet the safety goal? The answer is
16 yes, it would.

17 MR. OKRENT: Well, I'm sorry, excuse me. The safety
18 goal as it was formulated did not have a meaningful societal
19 risk measure. The comparison, where it goes out to 50 miles,
20 in my opinion is almost -- well, I will use a mild adjective
21 -- a misleading measure.

22 MR. ROSENTHAL: On earlies, I captured the earlies
23 close in. The latent scale is the person rem. If I shrink
24 this back to 50 miles, I'm going to halve the number. There
25 are other -- I should say to the proposed safety goal, and

1 perhaps this is then a meaningful way to define containment
2 performance. This answers the question about --

3 MR. OKRENT: Let me put it another way. I don't
4 think, in fact, it would be looked upon as highly acceptable
5 if it were thought that there really were a chance of one over
6 40 years to produce the man rem that goes with those latent
7 fatalities. I don't think that would be -- whether you met
8 the current safety rule or not, I think that indicates why the
9 current safety goal is deficient.

10 MR. ROSENTHAL: Now let's look at Dr. Ward's
11 question with respect to LOCA and assume that the LOCA
12 frequency is far higher, a larger contributor than the
13 transients in some broad sense. That switches me between the
14 1-TL3, which with igniters I think is the most probable
15 sequence, to as bad as a 1-SB-E1. That is a small break LOCA
16 without igniters and with early failure of the drywell, and my
17 consequences, my predicted consequences are in person rem an
18 order of magnitude. But again, low earlies. So from a risk
19 perspective, we should not belabor the precise frequency of
20 LOCAs.

21 Let's go to seismic --

22 MR. OKRENT: Excuse me. There is one other thing
23 that we need to keep in mind. The calculations of early
24 fatality and early injury are statistical results, so there
25 are some weather situations which lead to less effects and

1 some, let's say, which in fact are not so pleasant.

2 MR. ROSENTHAL: But the zero includes bad weathers.

3 MR. OKRENT: Oh, the zero.

4 MR. ROSENTHAL: If you really believe zero, you
5 really have to be happy about it because you have to have high
6 confidence. We sampled over 91 weathers. You are still
7 getting zeroes. You don't think this is fluke weather.

8 MR. OKRENT: In that case you are saying there is
9 sufficiently little release that it doesn't matter what the
10 weather.

11 [Slide.]

12 MR. ROSENTHAL: Seismic. The difference between the
13 prior slide, which was internal events, and here external
14 events is that we assume it was .5 or .6 g events that
15 evacuation is impaired. Seismic risk tends to dominate the
16 total risk perspective. And let me remind you these, again,
17 are conditional consequences. One can add in -- one has to go
18 back and say are there new containment failure modes that are
19 introduced by seismic events at very, very large g values. You
20 just have to assume that everything crumbles down. We just
21 extracted from Limerick an RSS-type release associated with a
22 massive failure.

23 Let's back up a bit and worry about an event which
24 moves the relative motion between the RHR, whatever building
25 you have out here, and the containment building.

1 [Slide.]

2 And the piping, the suction lines come right down
3 the pool and out. If you break that line, then you drain the
4 pool. Remember when testing the elements of this design it is
5 that they have pools. We are uncertain of the behavior of
6 that pipe given the SSMRP work and the shift work.

7 [Slide.]

8 But the seismic risk is dominated by blackout
9 events, and there you have to provide protection, dominated
10 at, let's say, .5 to .6 g. The SSE of the plant is .3 g, two
11 times the SSE, and that dominates the risk.

12 In comparison, the far higher g events cause the
13 more serious releases yet, but at some perceived reduced
14 probability. That was binned for our cost-benefit work into a
15 1-TI-2, and I believe that is a conservative category. If the
16 igniters survive, then you would expect what was called the
17 1-TL3, and if you recall, that was an order of magnitude low
18 in person rem.

19 One problem here is, given the blackout as the
20 initiator, it looks like some fluid systems that penetrate
21 containment would not isolate. They are closed fluid systems,
22 but of course they can leak, too.

23 The I2 sequence, in comparison, is one in which
24 you have assumed that the wetwell and the drywell have been
25 failed by a hydrogen-related event and that has happened at

1 some intermediate time.

2 This was brought up at the subcommittee meeting. The
3 current Rule 50.46 as revised does not require seismic
4 qualification of the igniters. Dr. Okrent was right in noting
5 that if you want to take credit for suppression of the risk
6 associated with the seismic events, you are relying on those
7 igniters and you ought to have confidence that the igniters
8 would survive, and I would say survive to at least .6 g.

9 Now, the igniters have a cabling. Cable trays look
10 okay. In all the plants that we know of, the igniters have
11 been seismically mounted, and since G.E. is committed to
12 follow what the owners will eventually do as a result of HCOG
13 on igniters, I presume that they would be seismically mounted
14 also, but there is no commitment on their part that I know of
15 at this time.

16 MR. SHEWMON: Are these things still a glow plug?

17 MR. ROSENTHAL: They are a glow plug. They ride
18 around in a diesel. A diesel goes over bumps in the road,
19 they get shaken up and vibrated and everything else, so I did
20 not write -- this came up yesterday.

21 MR. SHEWMON: Presumably it is a support system one
22 would have concern about, not the igniters.

23 MR. MICHELSON: I think you have to have concern
24 about the balance of the system that makes the igniter work,
25 too, not just the support.

1 MR. SHEWMON: I meant the support system.

2 MR. MICHELSON: More than the support, back to the
3 power supplies, and so forth.

4 MR. SHEWMON: You are talking about structural
5 support; I'm talking about anything electrical.

6 MR. MICHELSON: I like to think the function has to
7 be seismically qualified. That includes supports, includes
8 glow plugs and a whole lot of other things.

9 MR. EBERSOLE: Doesn't it include just the glow
10 plugs to switch down 2000 psi and diesel cylinders, wires
11 which are flexible and can be put in flexible conduit and
12 immune and removed from cable trays, and a source supply from
13 a battery which could be put in an enclosure that could
14 withstand a cannon blast? I fail to see the arguments about
15 making it seismic or any reason to think that there's any
16 particularly expensive difficulty in doing it.

17 MR. MICHELSON: You forgot controls; you can't leave
18 it on all the time.

19 MR. MICHELSON: You've got to see the details.

20 MR. EBERSOLE: There are so few details here there's
21 not enough to argue about.

22 MR. ROSENTHAL: I wanted to distinguish between
23 seismic qualified, which I would not necessarily recommend,
24 and having high confidence that they would survive. And the
25 first thing that I think one would do pragmatically is just

1 plain take your fragility people and have them take a hard
2 look at that device.

3 MR. WYLIE: Just a matter of education. That .6, is
4 that compared to what on a Richter scale?

5 MR. ROSENTHAL: I don't know how to do that.

6 MR. WYLIE: I was just trying to do some correlation
7 to earthquakes.

8 MR. OKRENT: Let me give you one place where we have
9 a sort of a measure, okay? At San Onofre 2 and 3 where there
10 is presumably or postulated to be a fault system which is
11 active offshore not too far away, a couple of miles roughly as
12 I recall, something like a magnitude 7 on the Richter scale
13 led to a design basis of .66g. That doesn't mean you wouldn't
14 get peaks larger than this, of course, but -- talking about
15 sustained.

16 MR. SHEWMON: That's twice as big as anything east
17 of the Mississippi, I think; almost three times.

18 MR. OKRENT: It's more than twice as big.

19 MR. WYLIE: What brought it to mind is, you know, we
20 heard the Chilean earthquake report last meeting, and that was
21 a .7 -- I mean, it was a 7 on the Richter scale.

22 MR. OKRENT: It depends on how close you are, of
23 course. In other words, if you're 50 miles away, the plaster
24 may crack in your house but it's not going to fall down. It
25 shouldn't, anyway.

1 [Slide.]

2 MR. ROSENTHAL: Now one attempts to do cost-benefit
3 analyses. We do cost-benefit analysis using person rem
4 averted at \$1000 a person rem; no present worth. I just
5 wanted to point out that the RHR pipe break massive rupture
6 event V are relatively small contributors to total person rem,
7 in our estimates.

8 Seismic dominates a way of giving you what from a
9 back end PRA view is a transient, and that the effect of the
10 igniters is to shift E1, I2, E3 events into the more benign L3
11 category. We have tried to distinguish between igniters and
12 perfect ignition here, but we didn't take full credit for the
13 igniters in doing these incremental person rem. And if you
14 believe the igniters will work more efficiently or you don't
15 believe the detonations in the first place, then you have a
16 greater tendency to bin stuff into the L3 category so you can
17 show some more cost-benefit.

18 [Slide.]

19 The plant does not have a remarkably low core melt
20 frequency according to our estimates of the range of 5 minus
21 5. What I have been showing you here is very low conditional
22 consequences. The first perception is that our results of
23 overall risk to a great degree hinge on what I consider
24 judicious use of source terms and the efficacy of the pool. I
25 think we were very conservative in the way we treated that

1 pool scrubbing.

2 Logic concerns do exist. The way we have approached
3 the problem there is a tendency to have over-estimated the
4 person rem and in turn, have over-estimated the cost-benefit.
5 Although as I showed you on the first slide, at least the
6 mechanistic ASTPO code suite numbers are not that much lower
7 than our high range numbers. We would choose not to base
8 conclusions based on cutting the pie that fine.

9 [Slide.]

10 The risk from external events is perceived to be
11 larger, far larger than the risk from internal events, and the
12 dominant contributor to risk is blackout type events, which
13 would happen with 25.6g range, as compared to the .3 SSE.

14 [Slide.]

15 In our assessment, as we show, the person rem from a
16 number of sequences are very similar. But that whole exercise
17 is critical to source terms, it's critical to pool bypass
18 which we think would suppress the space by requiring that
19 igniters be installed on the package supply.

20 I'd like to point out in site characteristics we use
21 the Shippingport site, and that, in some people's minds, is a
22 pessimistic site.

23 MR. MOELLER: Excuse me. When you list source term
24 values, are you meaning what comes out of the current
25 research? Or what do you mean?

1 MR. ROSENTHAL: Our cost-benefit analysis was based
2 on what we consider BNL or BNL staff high range values. They
3 were extracted from BMI-24 and other documents. Subsequently
4 we ran the code suite ourselves to see where we sat relative
5 to those estimates that had to be made two years ago in order
6 for me to be standing here today.

7 But this is essentially a new source term picture,
8 and one would get other results if one were to use old source
9 terms. I think we were judicious in use of the new source
10 terms. For example, in pool scrubbing you can see that the
11 pool scrubbing is a function of the particle size distribution
12 and goes through quite a valley. We centered the distribution
13 of the particles coming into the pool at the minimum value
14 with a fairly tight distribution. So we calculated a
15 scrubbing factor of 6 to 60.

16 GE likes to use values of 600 or 10,000. So I think
17 I can only come down.

18 MR. SHEWMON: Is there any reason for doing that?
19 You could have just arbitrarily thrown in a factor of 100 and
20 gotten the same results, couldn't you? You said you
21 arbitrarily took your distribution so it would be at the
22 minimum.

23 MR. ROSENTHAL: Yes.

24 MR. SHEWMON: What's the basis for doing that
25 instead of just saying we will derate things by a factor of

1 100 arbitrarily? Derate the pool scrubbing. Is there any
2 basis for doing that outside of you are now proud because
3 you've thrown an arbitrary factor of 100 into it, or what?

4 MR. ROSENTHAL: By doing what we did?

5 MR. SHEWMON: yes.

6 MR. ROSENTHAL: We have narrowed the range
7 discussion down to what is the particle size distribution into
8 the pool. And you have to say, do you know it and will you
9 ever know it, and not hide it behind other issues such as
10 scrubbing in the pool.

11 We had a great debate with GE. The advantage of
12 doing it is get up here and at least explain what I did and
13 where those conservatisms may come from, rather than hiding it
14 behind 20 values of parameters --

15 MR. SHEWMON: The answer to my question is there's
16 no justification but you focused the conservatism this way.
17 Is that it?

18 MR. ROSENTHAL: Yes, sir.

19 MR. SHEWMON: Would you tell me why Shippingport is
20 considered a pessimistic site?

21 MR. ROSENTHAL: Because it's located close to
22 Pittsburgh.

23 MR. OKRENT: But when you go out over long
24 distances, the Staff has frequently said most of the eastern
25 U.S. looks the same when you're comparing man rem. So I'm not

1 quite sure what that means.

2 Paul, I might note that to the extent that we have
3 reviewed pool scrubbing, we did some of it but it was not
4 something we devoted primary attention to. The one area
5 where I think our consultant raised questions was how well did
6 one know particle size and so forth.

7 And if you were to try to say that the pool
8 scrubbing was good for a factor of 1000 or 10,000, it forces
9 you to look that much harder and you are that much certain
10 that you are not bypassing; you're claiming a huge factor.

11 There is some kind of a tradeoff network to it.

12 MR. ROSENTHAL: The technology is just not there on
13 the back end reviews to derive central or mean values and
14 distributions. When one looks at conditional consequences
15 directly with what we perceived as at least high values, you
16 can get a perspective of what dominates the risk or doesn't,
17 and what the effect of having under-estimated or
18 over-estimated one sequence or another.

19 What I have attempted to do is to argue that our
20 risk perspective is insensitive to a great degree to the way
21 that we get to core melt and to the absolute values of those,
22 of core melt.

23 MR. OKRENT: Are there other questions for
24 Mr. Rosenthal?

25 MR. REMICK: I have one. One the one slide you had

1 conditional consequences, then you had probabilities at the
2 end. Those were probabilities of what? Do they include the
3 probability of core melt? Probabilities assuming a core melt?

4 [Slide.]

5 MR. ROSENTHAL: Here is the probability of a core
6 melt, probability of a 1 TL3. The probability of an ATWS, and
7 here is the consequences.

8 MR. REMICK: Okay. Thank you.

9 MR. OKRENT: Those numbers are with seismic or
10 without?

11 MR. ROSENTHAL: Yes. Let me point out that with
12 seismically qualified igniters, you shift the 1 to the E1 and
13 what we call the E1 max into that L3 category.

14 MR. OKRENT: In the SSER-4 --

15 MR. ROSENTHAL: These slides are extracted from the
16 SSER; they are just copies.

17 MR. OKRENT: On page 15-48 there is something called
18 a base case which says without UPPS you get one times 10 to
19 the minus 4, and with UPPS, 6.7 times 10 to the minus 5,
20 although here you don't show a big difference.

21 MR. ROSENTHAL: I'm having trouble responding to
22 you.

23 MR. OKRENT: The 5 is 1 right. It's not important
24 now. You might take a look at page 15-48 later and comment.
25 Don't try to do it now.

1 MR. ROSENTHAL: I just want to make the point that
2 we have defined performance not in terms of pressures and
3 temperatures but in terms of releases to the public and
4 consequences of those releases. And that's why I keep
5 focusing on the conditional consequences of core melt.

6 MR. OKRENT: Mr. Chairman, we might see what
7 General Electric would like to add to this discussion and then
8 break for lunch.

9 MR. WARD: Okay. We have used I think about 35
10 percent of the time allotted. Where are we on the agenda?

11 MR. OKRENT: Unfortunately, on the agenda we picked
12 up only 1 and part of 2.

13 MR. SCALETTI: And 4, 5 and 6, as far as the Staff
14 is concerned.

15 MR. OKRENT: 5, yes I think. And 4 we haven't
16 discussed I would say. 6 the Staff has discussed.

17 MR. SCALETTI: Could I make a comment on 4?

18 MR. OKRENT: I'm sorry, let's hold it.

19 MR. SCALETTI: I was just going to say the Staff is
20 not prepared to discuss it. The safety goal is not Staff
21 policy; it's only a proposal and we are not in a position to
22 discuss it anymore than we have. It will be discussed on
23 10/9/85 with EDO.

24 MR. OKRENT: He's telling you you may save 9 to 14
25 minutes there.

1 MR. WARD: Is there a mean or a median there?

2 [Laughter.]

3 MR. OKRENT: One minute to tell us that we're not
4 going to talk about it.

5 I would suggest we hear what GE wishes to add on
6 Item 2, and then break for lunch.

7 MR. WARD: All right.

8 MR. SCALETTI: This will be Dr. Debbie Hankins.

9 MS. HANKINS: This should be very short. I only
10 have three slides.

11 [Slide.]

12 This is simply a summary of our consequences and
13 risks for internally-initiated events. We were asked what are
14 those consequences most sensitive to. We did a sensitivity
15 study on the back end of the PRA and found that it is
16 relatively insensitive to core heatup, hydrogen generation,
17 primary system retention whether the RPV fails early or they
18 actually melt through the head, and the concrete composition
19 limestone facility.

20 At different times with the subcommittee and the
21 full committee, we have presented those results. The risk is
22 moderately sensitive to assumptions regarding the late release
23 of tellurium. This is primarily for the full bypass sequence
24 as to whether or not you have a high population site.
25 Obviously the consequences in the man rem are going to be

1 proportional to the number of people that you have out there.
2 The more people you have, the higher the consequences, and of
3 course, assumptions relative to suppression pool scrubbing.

4 I think that is very consistent with what Jack
5 Rosenthal presented on areas of importance.

6 [Slide.]

7 Relative to external events, seismic fire and flood,
8 the biggest contributor obviously was seismic in terms of
9 external events. The areas that are most critical are, of
10 course, seismic hazard curve, and we have had a lot of
11 discussion about seismic hazard curves, and secondly, pool
12 bypass potential because with seismic events you introduce new
13 potential containment failure modes, possible structural
14 building failure modes, the reliability of isolation valves
15 and the probability of drywell failure. This is simply
16 repeating what the Staff has said.

17 MR. REMICK: Question. On your risk, what assumption
18 do you make about the site we use? Do we use Shippingport
19 also?

20 MS. HANKINS: I'm glad you asked the question
21 because I did want to say something about that. We used Site
22 6 of the Reactor Safety Study. The reason we used that site
23 was because in doing a number of consequence calculations,
24 that site is very average in terms of meteorology and
25 population distribution, so for a given release of fission

1 products, you get an average consequence result, compared to
2 doing that same release over a wide variety of sites. So we
3 use Site 6 because we wanted a best estimate representation of
4 the GESSAR II risk.

5 Staff chose to use the Shippingport site. As I
6 mentioned, the consequences are very sensitive to -- in fact,
7 they are linear with site population. I would like to read to
8 you from SER 2 since this question came up yesterday of how
9 does Shippingport rate with other sites, and SER 2 states this
10 site possesses a greater surrounding population than 90
11 percent or more, and I would argue that we are talking high
12 90s when we say 90 percent or more. Maybe the worst site of
13 the existing nuclear plant sites in the United States.

14 So the consequences that have been presented by the
15 Staff represent about as bad as you can possibly get in terms
16 of siting a nuclear plant, and so when comparisons are made
17 with latent fatalities and risks calculated by G.E. for the
18 GESSAR design versus the Staff calculations, one has to keep
19 in mind there is a tremendous difference just due to the site
20 assumptions. It's not so much argument about containment
21 failure, about suppression pool scrubbing; there is a large
22 contribution there due to site, and I think we have lost that
23 many times in our discussions. I would just like to bring it
24 back.

25 MR. REMICK: Do you happen to know if Site 6 is

1 typified by any particular plant site that exists?

2 MS. HANKINS: It is a plant, eastern Atlantic
3 coastal plant site.

4 MR. EBERSOLE: What sort of numerical ratio are you
5 talking about?

6 MS. HANKINS: At least an order of magnitude.

7 MR. OKRENT: That's curious, in the following
8 sense. I have never done these consequence calculations
9 myself, but I have heard the Staff say orally and in writing
10 more than once when they were talking about siting that for
11 eastern sites, let's say east of the Mississippi, for latent
12 effects they find it hard to see more than a factor of 2
13 difference.

14 MS. HANKINS: For the majority of sites, that's
15 true. For the majority of sites, they usually leave out the
16 ones that are on the extremes, and Shippingport is an extreme.

17 MR. OKRENT: I must say they did not put in -- well,
18 Beaver Valley is not very far from Shippingport, so I would
19 understand them making the statement if -- I will just leave
20 it at that. I remain in a state of disarray with regard to
21 just what the facts are, if there are facts.

22 MS. HANKINS: I think one of the most useful
23 comparisons that could have been made, and was not made,
24 unfortunately, was to show the results with only changing the
25 site. We did that for the six sites in the Reactor Safety

1 Study. We showed the range there. But it would have been
2 nice to show the difference between just Site 6 and
3 Shippingport. I think that would have been good information.
4 Unfortunately, neither G.E. nor the Staff did that
5 calculation.

6 In summary, the areas of major uncertainty in terms
7 of both internal and external event consequence analysis were,
8 again, the seismic hazard curve, the component and structural
9 fragilities, particle size distribution that you just talked
10 about relative to suppression pool scrubbing, and, of course,
11 human error assumptions.

12 MR. OKRENT: Would Shippingport these days exceed
13 their 500 people per square mile thing and be excluded?

14 MS. HANKINS: I would have to leave that to the
15 Staff.

16 MR. OKRENT: Or Beaver Valley. In other words, does
17 Beaver Valley fall above or below your 500 people per square
18 mile curve?

19 MS. HANKINS: We built GESSAR there.

20 MR. REED: I don't know that explicitly. What I
21 would recommend to put this in context is that what we used
22 was NUREG-CR/2239, which compares all of the sites together
23 and you can get rankings from them, and Beaver Valley and
24 Shippingport are essentially the same, and they are virtually
25 always bridesmaids and never a bride. They are always in the

1 top dozen or so as far as a measure of badness is concerned,
2 but they are never really the worst.

3 We were trying to match as close as possible the
4 85th percentile, which was my instruction, to find a site that
5 did that, and I think we succeeded.

6 MR. OKRENT: I will say this once more. When some
7 years ago there was a discussion of should the Staff consider
8 more remote siting east of the Rockies, for a while they
9 seemed to be thinking that way. Then somebody came in with a
10 study which said, gee, when we do calculations of latent
11 effects, we can't get more than about a factor of 2 difference
12 among all the sites then in use, I have to assume, or at least
13 all of the sites that would not exceed this 500 per square
14 mile thing, implying that it was the number of people that
15 were 30, 40 and 50 miles away that was important, and that
16 tended to be similar for those sites.

17 MR. REED: That is correct.

18 MR. OKRENT: If that is correct, then I will remain
19 confused.

20 Okay, go ahead.

21 MR. WARD: Is that it?

22 MR. OKRENT: Yes.

23 MR. WARD: Well, we are right on target then, 12:30,
24 right?

25 MR. OKRENT: If that is when lunch was supposed to

1 be, then we are on target.

2 MR. WARD: Yes, that was it, and we have an hour and
3 40 minutes for this afternoon -- an hour for lunch, and an
4 hour and 45 minutes for GESSAR.

5 MR. OKRENT: I am assuming we may be running an
6 extra half-hour.

7 MR. WARD: We don't really have that much
8 flexibility, Dave.

9 MR. OKRENT: We can't run late?

10 MR. WARD: I guess we can, but we are already
11 scheduled for 6:45, so we have to be realistic.

12 Okay, let's break until 1:30.

13 [Whereupon, at 12:35 p.m. the meeting was recessed,
14 to resume at 1:30 p.m. the same day.]

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AFTERNOON SESSION

[1:30 p.m.]

MR. WARD: Let's return to the discussion of GESSAR.

MR. OKRENT: The next agenda item relates to interface requirements. I should note that there appears to be something like one would assume was the normal kind of interface requirement documents in existence that GE has prepared.

What is less clear is the extent to which interface requirements will impose some kind of a requirement that the systems involved will have the performance reliability, whatever is assumed in the PRA.

If it turned out, for example, the service water system in the ultimate heat sink, which is part of the balance-of-plant, were really very unreliable, this would affect one's conclusions that one heard earlier, and so some -- in fact, many of the kinds of conclusions that the Staff is drawing and GE are based on some assumptions concerning performance in the balance-of-plant. And we thought it was relevant to see to what extent, in fact, there existed any kind of quantitative requirements, and if so, what was their nature, et cetera. And so we will hear something about that.

I guess we will hear from the NRC first, and then from GE. Hopefully, it will be direct and to the point.

MR. SCALETTI: Dino Scaletti from the NRC Staff.

1 Let me just quickly state -- and I will be to the
2 point -- the reason for interfaces is due to, the application
3 for GESSAR II is for a design which does not include a total
4 nuclear plant. Therefore, interfaces are required.
5 Documentation and interfaces are required to assure the Staff
6 that the requirements of the Standard Review Plan and the NRC
7 regulations will be complied with at the time an application
8 comes in.

9 Also, as part of this, the Commission's Severe
10 Accident Policy Statement, which sets forth the requirements
11 for a severe accident review, these also require that the
12 Staff document and also that GE document certain interface
13 criteria to make sure that this policy is complied with at the
14 time that an application would be submitted.

15 I have mentioned in the past -- and we have
16 discussed this issue of interfaces in the past with the full
17 committee and also with the subcommittee -- the interfaces,
18 from the Staff's standpoint, that they have required of GE for
19 the GESSAR design, believing that these were additional
20 interface requirements were necessary to fulfill the
21 requirements that I had mentioned, are identified in Section
22 1.10 of the SSER, the SER, and all of its supplements.

23 I had compiled a list for the subcommittee meeting.
24 I guess I somewhat misunderstood the context of Dr. Okrent's
25 question when I wrote it down last night at the conclusion of

1 the subcommittee meeting. I do have a copy of it that I could
2 give you here of what we passed out last night. This
3 identifies the severe accident interface, where it is located
4 in the SER, and also if there is a quantitative requirement
5 related to that interface.

6 MR. OKRENT: I'm really a little bit miffed at any
7 misunderstanding. We had been trying for a few meetings to
8 ascertain, are there quantitative requirements, and if so,
9 what they are, and you were specifically advised that we were
10 not looking for a long list of places to look where we might
11 find something.

12 MR. SCALETTI: Dr. Okrent, that's what I gave you
13 last night, was wherever they were. I excerpted the portion
14 of the SER and included it under the interface identified in
15 the list that I had given to you.

16 MR. OKRENT: Mr. Denton is interested in expediting
17 this review, and if you can't provide us with the specific
18 information as to whether and what the quantitative
19 requirements, if any, are of the Staff, we will wait another
20 meeting.

21 MR. SCALETTI: Dr. Okrent, I gave you that list
22 and identified the requirements, as they were specified.

23 MR. MICHELSON: Could we have a copy of what he gave
24 you?

25 MR. OKRENT: I don't have anything. I'm sorry.

1 MR. MICHELSON: He said he gave you a list. I'd
2 like to see the list.

3 MR. OKRENT: I have no list. There's a song, "I
4 Have a Little List," but that wasn't my song.

5 MR. SCALETTI: The list was passed out at the
6 subcommittee meeting yesterday.

7 MR. MICHELSON: That list. That's not really any
8 help at all.

9 MR. OKRENT: Is that all the Staff has at this time
10 on the subject?

11 MR. SCALETTI: Unless you have some questions.

12 MR. MICHELSON: I have a question. As an example, I
13 was trying to search out real quickly the one that Dr. Okrent
14 gave, the example Dr. Okrent cited, although I was looking at
15 it earlier this morning, and that is the service water system,
16 just to see what is said in the GESSAR II, what is said in the
17 SER, and so forth.

18 All I could find -- but perhaps GE could correct me
19 and tell me where I should have looked -- I looked in Chapter
20 9. I looked at page 9.2-4, and in there it says that the
21 Applicant is to provide a description of the service water
22 system outside of the nuclear island, the ESW flow rates, and
23 establish interface requirements for the BOP. Then they give
24 the table where the flow requirement is prescribed. That's
25 all GESSAR seemed to say about the emergency service water in

1 terms of Applicant's requirements.

2 It also reference 9.2-5 for a description, and I
3 went to 9.2-5, and it said that the Applicant will supply
4 that. So that was not any help.

5 So then I went to your SERs and looked at the
6 Interface Section, 1.2 I believe it was, and all that is is a
7 list of the systems that might have interfaces, and service
8 water wasn't even listed. But I might have missed it. I was
9 looking at Table 1.2.

10 So that didn't help much, so I went to the SER
11 section dealing with service water, and it just says, yes, the
12 Applicant is going to do some things.

13 But I'm searching to where is -- did you ever even
14 see an interface document on service water, and if you did,
15 where did you reference the review of it?

16 MR. SCALETTI: Table 1.9 of GESSAR should identify
17 -- not the SER now -- Table 1.2, I believe, in the text, it
18 says that not all of the -- this is the table that exists
19 that's two and a half pages long of identified interface
20 items. It is not totally inclusive of all of the interface
21 items on GESSAR II. The complete list from the standpoint of
22 General Electric is provided in Section -- I believe it's 1.9
23 of GESSAR.

24 MR. MICHELSON: It wasn't on your Table 1.2, and
25 it's a pretty important system, probably one of the most

1 important systems.

2 MR. VILLA: Maybe I can clarify. I went back,
3 because we had this discussion yesterday, and I went back to
4 San Jose last night by phone and checked specifically the
5 emergency service water, and I found that it was easier to
6 deal specifically with Section 9 in the SER, the same section
7 that you were looking at. And in the SER, and after
8 discussing with some other people, the requirements for the
9 emergency service water are listed in the General Electric
10 document, and they include such things as heat loads, flow
11 rates, design pressures, temperature of the piping, chloride
12 content, and reliability.

13 MR. MICHELSON: How is that document at all tied
14 into GESSAR II or into at least the SER? Is there a path --
15 see, I was told earlier by the Staff, and you agreed, that all
16 I ever need to look at is GESSAR II and its amendments plus
17 the SER and its amendments, and that's all I'm going to look
18 at.

19 If it isn't somehow referenced in there, then I have
20 to assume it doesn't exist, even though you say it does, and
21 that's fine. It certainly ought to.

22 MR. VILLA: If you look at the same set of
23 information, if you look in Table 9.2-1 of GESSAR --

24 MR. MICHELSON: I put it back on the shelf.

25 MR. VILLA: I have it -- which I believe at first

1 glance may be a typographical error in the SER, because it
2 mentions Table 1.1 instead of 9.2-1 -- I'm sorry -- it's 9.1-1
3 in the SER, and I have in front of me 9.2-1, which begins
4 "Essential service water," listing heat loads, flow rates, et
5 cetera.

6 MR. MICHELSON: But that's not -- it doesn't even
7 list or mention or reference your interface document. I
8 assume that that table in the FSAR applies all right.

9 During all of our subcommittee meetings, we kept
10 saying, "It's in the interface document," and I said, "Well,
11 have you reviewed the interface document, and how do I know"
12 and so forth, and we never got a halfway decent answer, even
13 until today, and now I've got the answer is, "If it isn't in
14 the document you're looking at, then it doesn't help."

15 I'm confused.

16 MR. VILLA: Let me say, in the table are also lists
17 of all of the applicable document numbers that define the
18 design of each component of the system.

19 MR. MICHELSON: Document numbers? You mean
20 specification numbers?

21 MR. VILLA: Right. What we call a master parts
22 list.

23 MR. MICHELSON: A master parts list includes a spec.

24 MR. VILLA: It includes a whole pile of information.

25 MR. MICHELSON: That's Table 9.2-1. That's the one

1 I need to look at.

2 MR. SCALETTI: There is also in Table 1.9-24 --
3 Table 1 9-24, which has yet to be amended, to the GESSAR II
4 document, which is a severe accident interface with regard to
5 the emergency service water system.

6 MR. MICHELSON: Could I see a typical page?

7 MR. VILLA: Yes. I just picked it up.

8 [Document handed to Mr. Michelson.]

9 MR. MICHELSON: Where is this master parts list? I
10 thought that was an equipment number as a drawing reference
11 and not as a master parts list number. Then I was mistaken?

12 MR. VILLA: I am most familiar with the ones that
13 begin with the GE system, which is a letter and a two-digit
14 number and a dash.

15 MR. MICHELSON: So I am to assume, since this is in
16 GESSAR II, the Staff went through and sampled as they wished,
17 these equipment numbers and the documentations associated with
18 them under that number. Is that right?

19 MR. SCALETTI: If it's in GESSAR II, that's correct.

20 MR. MICHELSON: So if I picked two or three of these
21 number and go back, somewhere in your files is a piece of
22 paper that shows that you have it and whether or not you
23 looked at it?

24 MR. SCALETTI: I can't answer that.

25 MR. MICHELSON: Isn't that the orderly way?

1 MR. SCALETTI: I would assume, yes. I would have to
2 check with the reviewer of that information.

3 MR. MICHELSON: If these are indeed GE part numbers,
4 I'm acquainted with the documentation that goes with those,
5 and this would be adequate. I didn't interpret "equipment
6 number" that way.

7 MR. VILLA: Do you want to hear anything else from GE
8 on the subject?

9 MR. OKRENT: I would like to have GE tell us what
10 quantitative interface requirements are included in the
11 interface requirements, and please don't refer me to pages and
12 so forth.

13 What are the specific values for what systems?

14 MR. VILLA: I can give you specific values for the
15 emergency service water system. For example -- not all of
16 them; I just don't have them -- one example is, on some
17 piping, we have a 150 psig limit at 150 degrees Fahrenheit.
18 That also is listed here in GESSAR.

19 On the chilled water systems, to pick up another
20 question that Mr. Michelson asked yesterday, we require a 70
21 db notch test at 40 degrees Fahrenheit in accordance ASME
22 Section 3 for all pipes smaller than two and a half inches
23 thick. And for pipes greater than two and a half inches
24 thick, we require the service water temperature minus 100
25 degrees Fahrenheit.

1 I have to search for more numbers if you want to see
2 them.

3 MR. OKRENT: I thought you said there were some
4 reliability numbers. It was either performance -- by
5 "performance" I mean availability, reliability, this sort of
6 thing, things that enter into the PRA.

7 MR. VILLA: Kevin Holtzclaw will answer that
8 question.

9 MR. HOLTZCLAW: After we completed the PRA study, in
10 order to respond to the concern of how do you make the PRA
11 become a reality as far as the construction of the plant goes
12 and construction and operation of the plant, we identified
13 additional interface requirements, which specified such things
14 as reliabilities that were assumed in the PRA for areas
15 outside of GE's scope and that would make that incumbent on an
16 Applicant referencing the GESSAR II, to verify that his
17 balance-of-plant design met those reliability targets that
18 were utilized in our study, or provide alternative studies
19 that would show that, given a reliability estimate for one of
20 his supplied systems, it would be acceptable from the
21 standpoint of meeting the bottomline results of the GE PRA
22 study.

23 MR. OKRENT: Could we have -- do you have a copy of
24 the document that gives that? Has something been filed? Is
25 it a part of GESSAR II? It's not clear to me.

1 MR. HOLTZCLAW: I don't have a copy of the document
2 with me, Dr. Okrent. We did supply it to the Staff on the
3 GESSAR docket.

4 MR. SCALETTI: It's dated July 13, 1984, and this is
5 the document that I alluded to a moment ago that will be
6 amended to Table 1.9 of GESSAR. I have a copy of it here, if
7 you would like to look at it. It covers additional table
8 entries for actions and considerations on GESSAR.

9 MR. OKRENT: I think it would be helpful to make a
10 copy available to Mr. Major, so he could Xerox copies for the
11 members of the committee, and we can see what it is and go on
12 to something else temporarily.

13 MR. MICHELSON: I have a follow-on question. Just
14 to make sure that it doesn't slip away -- and remember now,
15 looking at the table this morning in the FSAR -- and what I
16 didn't find in there was those devices that belonged to the
17 scope of supply of the Applicant. There are no master parts
18 lists, numbers, or anything else listed, because you haven't
19 even -- I went to the flow diagram, and you just say what is
20 coming from the Applicant. I don't think there's anything on
21 any devices. That lists covers the flow diagrams, but I don't
22 think it covers the balance-of-plant part.

23 MR. VILLA: For example, Document No. E-12-B001,
24 which defines the design of the Archer heat exchanger, does
25 two things. Number one, it references an interface

1 requirements document --

2 MR. MICHELSON: You mean, if I go to that document
3 that is referenced here, I will find another document
4 referenced? Is that --

5 MR. VILLA: Not just one, you'll find many.

6 MR. MICHELSON: I'm interested, as another point, do
7 we chase every conceivable document that's referenced as we
8 work down the road, and all of those have been covered by NRC
9 as a part of your review?

10 MR. SCALETTI: I'm not saying every document has
11 been covered.

12 MR. MICHELSON: You are taking responsibility for
13 auditing, if you will, every one of those.

14 MR. SCALETTI: Be also assured that we looked at
15 Table 1.9, and the Staff reviewers who reviewed the various
16 systems that are required as part of their review of the
17 Standard Review Plan would identify those portions that are
18 missing. They would, in turn, look at that to make sure that
19 this was included as an interface, as I mentioned.

20 MR. MICHELSON: So that covers ever reference that
21 might be referenced in a reference. That's what he's citing
22 now. He's citing a reference in GESSAR which, in turn,
23 references some other document, and you are saying that you
24 have also chased that document, if you wished.

25 MR. SCALETTI: If we wished, we could chase the

1 document.

2 MR. MICHELSON: Therefore, it's a part of the FDA
3 approval.

4 MR. SCALETTI: If it is so identified.

5 MR. MICHELSON: That's a really encompassing package
6 of paper when you start going to the references of the
7 references. I didn't think you were doing that. If you are
8 going that far, I'm sure you're covered, because it's all
9 referenced in GE material somewhere, I'm sure.

10 MR. VILLA: I think you have to recognize that, for
11 example, our document structure starts at a top level. There
12 are seven levels of documents in our structure, and it starts
13 with a small number, actually like maybe 200 items for the
14 NSSS.

15 MR. MICHELSON: I am quite acquainted with GE's
16 system of documentation, because I was aware of how they set
17 that up, all right. I guess I didn't realize the Staff took
18 responsibility for all the references to the references as
19 well.

20 MR. SCALETTI: I'm not saying we considered all of
21 them. I'm saying we are sure that the interface list is
22 adequate from the standpoint that the items have been
23 identified, that there are interfaces, and it's well
24 documented. This part of the review has not been completed
25 yet.

1 As I said yesterday and I think perhaps before, the
2 interface items, the balance-of-plant and other interface
3 items, will be reviewed at the time they come in with an
4 application, and they will be reviewed to the Standard Review
5 Plan that's in effect at that time.

6 MR. MICHELSON: I thought they would just come under
7 the backfitting rule, though, and as long as they were
8 described in the FDA somewhere, and you are saying even in
9 references to references, then I thought those items, you
10 could not go back and change.

11 MR. SCALETTI: That's not my understanding, no.

12 MR. KERR: Mr. Chairman, I apologize for not having
13 an appropriate background to appreciate this discussion. What
14 is it we are trying to do here? It almost sounds as if we
15 have concluded as a committee that we review every detail of
16 the design.

17 Since I don't think we do that, what is it that we
18 are trying to do?

19 MR. MICHELSON: We're trying to identify the scope
20 of the FDA approval, knowing which things now cannot be gone
21 back and changed without coming under the backfit rule and
22 whatever.

23 MR. KERR: What does that mean, to identify the
24 scope?

25 MR. MICHELSON: It means, what did the Staff approve

1 when they issued the FDA? What description, what plant were
2 they approving? There has to be a description of it.

3 MR. KERR: So we want a list of --

4 MR. MICHELSON: We want to know documents form the
5 basis of the FDA approval, and what were the limits of the FDA
6 approval?

7 MR. KERR: What will we do with that information
8 once we have it?

9 MR. MICHELSON: Now we know what things to look at
10 in terms of our review. We don't look at limits of the FDA,
11 for instance. We also look to see that important things are
12 within the limits of the FDA review.

13 MR. OKRENT: Can I give an example that might be
14 appropriate?

15 MR. KERR: I don't know.

16 MR. OKRENT: Let me try. There is an issue the
17 committee has concerning the Palo Verde Plant where the
18 auxiliary feedwater system was supplied by balance of plant.
19 the venodr-proposed design did not have a feed and bleed
20 capability. He did say he, I think, in some way that he
21 expected the balance of plant to provide truly reliable
22 auxiliary feedwater system, but the system that was in fact
23 supplied was the minimum that would pass the Staff's recipe
24 for calculating reliability.

25 So here was a case where you ended up with what some

1 committee members consider a possible shortfall in combined
2 capability. That is what the vendor supplied and the balance
3 of plant --

4 MR. KERR: You are referring to a set of committee
5 standards. That's a different set than --

6 MR. OKRENT: No, I'm saying there was not an
7 interface requirement by the vendor --

8 MR. KERR: I recognize interface requirements are
9 important --

10 MR. OKRENT: To a three-pump system.

11 MR. KERR: It sounds as if we are somehow trying to
12 get the list of everything that goes into a nuclear power
13 plant, and since I know we are not trying to do that --

14 MR. MICHELSON: I'm trying to identify -- to cover
15 and identify what is covered by an FDA. Is it an open-ended
16 approval or is it a closed approval? If it's closed, where
17 are the boundaries identified? We first thought maybe it was
18 even open ended, which would be unacceptable, and so we tried
19 to and I think we finally got a definition of the boundaries,
20 which is that written statement that you have in front of you,
21 which is a good definition of the boundaries.

22 I was just trying to search out to make sure,
23 though, I understood what those words meant, and they mean
24 quite a bit more than just what is stated there because now it
25 means the boundaries are really in the references to the

1 references, which means I have to do a lot of chasing to find
2 out how far they might have proved.

3 That is fine. I just want to know where they are,
4 and I think I know. It is not that I necessarily think it's a
5 very good idea. I'm just trying to understand it.

6 MR. SCALETTI: Did you understand what we identified
7 as interface is not Staff approval of the design that's coming
8 in in the future?

9 MR. MICHELSON: If it is in the FDA, if it is a part
10 of the FDA, if it's in GESSAR, et cetera, then I think you
11 cannot change, you cannot require a change of that design
12 without going through the backfitting rules. That's all I'm
13 looking at. So I know what is defined is what they will
14 supply. But you can't require more, and even if you never
15 looked at it and didn't realize it, you can't require more.

16 I just wanted to figure out the scope of possible
17 mistakes that can be made in review simply because there is an
18 enormous amount of material to review with limited resources,
19 which I fully recognize. I think you have defined a scope far
20 larger than you could ever possibly review.

21 MR. OKRENT: Could I get back to Item 3 and ask the
22 Staff if they have any quantitative interface requirements
23 other than those that are on this General Electric table,
24 which I thought was being Xeroxed?

25 MR. MAJORS: It is being Xeroxed.

1 MR. OKRENT: And which we will receive to look at.

2 MR. SCALETTI: Yes, and the list that I had given
3 you yesterday, and I believe you have a copy of now, there are
4 the interface requirements that fragilities of components be
5 met identified in Supplement 3. We can call those out.

6 MR. OKRENT: Are there others besides the ones on
7 fragilities?

8 MR. SCALETTI: There are some specific ones on
9 aircraft strike, on hazardous materials. These are under the
10 SRP. There would be some specific requirements associated
11 with the CPML Rule.

12 MR. OKRENT: Okay. Those are they, then, if I
13 understand it.

14 All right. Well, I think at this stage --

15 MR. SCALETTI: Excuse me. There will also be the
16 interface requirements or the FDA conditions associated with
17 upgrading a UPPS ten-hour station blackout capability, a
18 dedicated backup power supply for the igniters, and a seismic
19 upgrade of UPPS.

20 MR. EBERSOLE: May I ask a question as an example
21 here? In the GESSAR II, does the system preclude the case
22 which occurred at River Bend where the third high pressure
23 diesel was, in fact, not independent but it got its service
24 water from the other two diesels? Does your system look up a
25 set of requirements that preclude that occurrence?

1 MR. VILLA: Maybe I can answer that. I believe it
2 does.

3 MR. EBERSOLE: I think it does, too.

4 MR. VILLA: Our design -- the service water design
5 is clearly defined in GESSAR.

6 MR. EBERSOLE: It's yours.

7 MR. VILLA: Yes.

8 MR. OKRENT: Okay. I would suggest we go on to Item
9 7, time being what it is. We may want to come back to No. 3
10 later if there is time.

11 Let me say with regard to the USIs and GSIs, the
12 subcommittee yesterday listened to the Staff comments on their
13 resolution, and leaving the question of sabotage aside, we did
14 not go into station blackout or decay heat removal --

15 MR. EBERSOLE: Dave, on that particular item you are
16 talking really about another interface. You are talking about
17 Item 7 now?

18 MR. OKRENT: Item 7. Let me introduce A43.

19 MR. EBERSOLE: It is A43. It is an interface
20 requirement. I call out the fact they are using
21 hydrochlorides. They do not define the insulation and so
22 forth that would act as a contaminant, which these
23 hydrochlorides have to handle. It's a good example of the
24 absence of an interface.

25 MR. OKRENT: That is one of the questions that

1 seemed to persist during the subcommittee meeting, and the
2 other question that seemed to persist was, as we understood it
3 from the Staff, one of the bases for them saying that A43,
4 which you may or may not recall relates to problems of
5 blockage of the flow into the pumps that would get water from
6 sumps, was that the UPPS system would make it unnecessary to
7 use these systems and so therefore you didn't really have to
8 look that hard at how it was to be resolved.

9 There was a further reason given, which was they
10 anticipated that for existing plants there would be no
11 hardware changes required. Maybe a notice alerting operators
12 that they should be aware of this potential, I guess sort of
13 like the Surgeon General's message.

14 But anyway, with that background, what comments does
15 the Staff wish to add, or clarification on A43?

16 MR. SCALETTI: I made a comment yesterday on A43
17 indicating that -- I guess I was a little bit too brief on
18 the reason for resolution. It is not strictly UPPS. We had
19 talked about -- although that is a factor, that is a
20 possibility. It is another way to get water to the core.
21 There are other ways to get water to the core, too, that
22 follow a large break LOCA, which was the concern, that UPPS
23 was not designed to accommodate a larger break LOCA.

24 We had talked about oversize strainers and the
25 position of the RHR intakes within the pool. There is also a

1 requirement on page 6.25 of the SER which relates to strainer
2 configuration, and demonstrating by a utility applicant that
3 the mesh of the strainers have the possibility of blocking out
4 a certain amount of debris and cannot be blocked by one piece
5 of large debris.

6 G.E. has also committed to use a reflective type of
7 insulation in the primary system, which will reduce the
8 possibility of plugging the intake strainers. As I mentioned
9 before, the other ways to makeup to the core were the high
10 pressure core spray, I believe there is -- you will have some
11 time following a large break LOCA that your systems will not
12 be totally incapacitated and not be able to use, and we have
13 done some brief calculations which indicate that we would have
14 probably approximately 25 minutes to a half-hour before you
15 would have to go to a system like UPPS.

16 MR. EBERSOLE: I must have missed this. You say
17 G.E. has committed to reflective preliminary insulation?

18 MR. OKRENT: That's correct.

19 MR. EBERSOLE: Fine. That just about puts that to
20 rest.

21 MR. OKRENT: Any other questions on this?

22 [No response.]

23 Let's go on to Item 8. Here the picture is in its
24 PRA G.E. examined internal flooding. When the Staff tried to
25 review this, certain difficulties. Insufficient information

1 on the details of design, they say, made it difficult for them
2 to agree or disagree. I will let them use their own words.

3 MR. SHU: Calvin Shu from Brookhaven National
4 Laboratory. I would just like to take a couple of minutes to
5 summarize the overall review process and some of the findings
6 that we have arrived at to give you a brief overview. BNL was
7 originally requested by the NRC to review the internal
8 flooding PRA submitted to the NRC.

9 It was a limited review. We were asked to spend
10 about four man weeks to review the whole effort. So in the
11 process, we are not able to arrive at a new, independent core
12 damage frequency due to internal flooding events. We have one
13 round of questions with General Electric in which we tried to
14 seek clarification and additional information, and they did
15 provide a response to us.

16 What G.E.'s studies essentially entailed was
17 examination of the different potential flooding areas based on
18 the FSAR evaluations. Their flood-initiating frequency was
19 very low, in the order of 10^{-6} to the minus 6, 10^{-7} to the minus
20 7, or lower, depending on the area.

21 What BNL did was review the initiating frequency,
22 and also we reassessed the potential flooding initiating
23 frequencies based on maintenance-induced floods and
24 rupture-induced floods. We would divide them into two broad
25 categories. There are flooding events inside the plant that

1 could come from -- throughout the maintenance process,
2 inadvertent openings in isolation valves and so on and so
3 forth.

4 Then on the other hand, there are also
5 rupture-related pipings and whatnot. We have assessed the
6 frequencies, and they are in the order of 10 to the minus 4.
7 Also, as part of the review, we have identified blowout
8 opening that connects the RCIC room with the RHR room. This
9 is a little different than what G.E. has initially suggested
10 as to their complete independence of their rooms.

11 We identified that there may be a potential leakage
12 path from the corridor back into the ECCS room if flooding
13 exceeds the 15-inch flood height. We did not pursue the
14 scenario to the ultimate in terms of identifying core damage
15 contribution coming from these particular sequences; however,
16 we made an estimate using the following assumptions.

17 If we assume that the ECCS rooms are indeed
18 independent, that there is no communication from one room to
19 another, and also if we assume that whatever critical
20 components is within one ECCS room, if they got inundated by
21 flood would not affect the operation of equipment or
22 components in adjacent or other rooms, then we believe the
23 core damage frequencies will be low. By that I mean we
24 estimate it will be in the order of 10 to the minus 6, 10 to
25 the minus 7 or lower.

1 That in a nutshell is a brief summary of what we
2 have done for internal floods.

3 MR. OKRENT: Are there any questions?

4 MR. MICHELSON: Just for clarification, did you look
5 at the reactor water cleanup system break as part of your
6 study?

7 MR. SHU: We have identified a number of different
8 types of lines, and that was one of the systems that we have
9 looked at; but again, in terms of initiating frequencies, we
10 identified --

11 MR. MICHELSON: By looking at, what do you mean? Do
12 you mean you actually went in and postulated such breaks and
13 followed where the water and the steam went and so forth?

14 MR. SHU: No. Let me repeat again. We are not able
15 to follow the sequence through to core damage. What we did
16 was we looked at the system identified, we approximated the
17 length of pipe and the rupture frequencies due to that pipe
18 and whatever maintenance -- you know, because heat exchanger
19 has to be maintained. It fails, and based on some rough
20 number on maintenance frequencies and failure to maintain the
21 integrity of the isolation valves and leading to a
22 flood-initiating frequency.

23 Beyond that --

24 MR. MICHELSON: Let me ask the question differently,
25 then. In the process of doing your examinations, you only

1 applied the single-failure criterion. You didn't question,
2 for instance, whether the isolation valves would close but
3 rather assume one of them might not but certainly not both?
4 Is that the approach you used in doing this flooding study or
5 did you assume the valves didn't close?

6 MR. SHU: I don't think I'm making myself clear. We
7 did not go and follow the scenarios beyond the initiating
8 event. So once we postulated a rupture, I did not go back to
9 even ask whether the valves would work or not.

10 MR. MICHELSON: You said something about it didn't
11 lead to core melt, so I wondered what basis you used in making
12 that decision. I thought you said it didn't lead to core melt
13 and that's why you didn't go further, but maybe I
14 misunderstood you.

15 MR. EBERSOLE: How could you do a flooding study if
16 you did or did not specify the valve closed or didn't close?

17 MR. SHU: We didn't do a flooding study. We only
18 spent four weeks' time doing a brief review of what G.E. has
19 done, and our review entails some reevaluation, reassessment
20 of the flood-initiating frequency. That means how likely was
21 the frequency, likelihood of a particular type of flooding to
22 occur. After the onset of a flood what would happen, we did
23 not have the time and the resources to go into.

24 MR. MICHELSON: I'm going to withdraw my question.
25 Thank you.

1 MR. OKRENT: Okay. Since we have only about, at
2 most, an hour and 15 minutes left, if we go 15 minutes
3 overtime, I think that's all the Chairman will give me. We
4 had better move along because we are going to need Item 12.
5 There are some things other. Could G.E. summarize in five
6 minutes instead of ten?

7 Could you summarize how you propose to approach it?
8 The committee will hear more about it in a different sense
9 tomorrow.

10 MR. HOLTZCLAW: Kevin Holtzclaw from General
11 Electric. I should start out by -- in light of what you heard
12 in one of the subcommittee meetings yesterday and what you
13 will be hearing tomorrow -- with the statement that we did not
14 have a detailed operational procedure for containment venting
15 for GESSAR. That would be part of the plant operational
16 procedure guidelines, or operating procedures rather, for the
17 specific plant.

18 However, as required by the emergency procedure
19 guidelines, we would surely intend to have that capability, or
20 have the vent capability in GESSAR, and such things as the
21 selection of some of the detailed parameters for containment
22 venting which would be part of the detailed procedure have not
23 as yet been determined for GESSAR like vent pressure criteria
24 and some of those specific parameters.

25 We can now tell you what we believe some of those

1 parameters depend on and how vent pressure would be defined as
2 well as the appropriate vent pathways.

3 The venting pressure depends a good deal on the
4 pathway chosen as far as having the operability of components
5 along that pathway to ensure that they can stand any pressures
6 that might be induced; things such as the SRV air system
7 pressure, the valve-operated pressures along the pathway or
8 capabilities, the limitations that might be imposed on
9 containment pressure indication itself. So that the operator
10 -- we would propose a pressure that the operator would have
11 some reasonable capability of knowing what that containment
12 pressure was during that sequence.

13 And then finally, the ultimate containment pressure
14 capability itself would be another parameter, another item
15 that the choice of a vent pressure criteria would depend on.

16 In looking at the GESSAR design, there are two
17 methods of venting that we have considered would be
18 appropriate pathways. One would be through the normal
19 containment purge system which is a seismic Class 1. The
20 other is a specific vent line as part of the UPPS system.
21 I'm sorry. That's not necessarily a dedicated line just to
22 UPPS but it is a line that is specifically associated with the
23 UPPS system.

24 Some of the objectives --

25 MR. WARD: Wait. I didn't quite understand that.

1 It's not dedicated? You mean the UPPS would operate the
2 existing vent line?

3 MR. HOLTZCLAW: The existing line. And we're
4 thinking specifically of a line that was identified as a
5 result of CPML rule requirements that called for a dedicated
6 line in the event that containment venting was believed to be
7 an appropriate action. The CPML rule required such a
8 capability.

9 Some of the objectives that we have thought of in
10 terms of choosing vent criteria and vent pathways is a desire
11 to vent from the wetwell as opposed to the drywell in the
12 multi-compartmented containment design, which would maximize
13 the capability of the suppression pool to trap fission
14 products in the event of radionuclide release.

15 Sizing of the line is another concern, or lines;
16 looking at what lines are available with the intent of being
17 able to vent from minimum-sized lines as a first order of
18 priority, and then looking at exactly when in specific
19 sequences venting would be initiated.

20 That's some of the thoughts in our minds as far as
21 engineering such a system and as identifying appropriate
22 procedures.

23 I know one point that is also not on the list that I
24 just went through would be to carefully choose a pathway so
25 that you don't necessarily exacerbate an accident condition

1 that caused you to vent in the first place. And looking at
2 things like the line integrity, for instance, and assuring
3 that you might not necessarily be going through a line of
4 hardened pipe and come up on ductwork that might be adversely
5 affected by high pressures, which could have an implication on
6 the environment outside of that ductwork, given the potential
7 for losing that integrity.

8 MR. EBERSOLE: What sort of discipline is there at
9 the present time required of the owner/operator if he proposes
10 to do something --

11 MR. OKRENT: Jesse, I wonder if we could sort of cut
12 short the discussion on this topic today. It's going to be
13 discussed tomorrow. It's one of the --

14 MR. EBERSOLE: I wanted the generic process, though,
15 in case we liberate this process to the utilities as has been
16 proposed.

17 MR. OKRENT: The Staff has liberated it. We'll have
18 to backfit if we're going to do anything. But if you're
19 agreeable --

20 MR. EBERSOLE: Sure. I will bide my time. How's
21 that?

22 MR. OKRENT: I'm trying to save you and Glen time in
23 the end, among others. Unless there are burning questions on
24 this, I would suggest we go on to number 10, which is shown as
25 GE, but perhaps the Staff also has comments here. In other

1 words, what is the current status of UPPS. And then, as you
2 see there, questions have been raised -- will UPPS work in the
3 event of a fire? This could depend on the size of the fire.
4 And members have raised questions about should it be a more
5 encompassing system, a better system, and so forth.

6 I don't know whether the Applicant or the Staff has
7 any comments in that area or not. But anyway, could we assess
8 the status of UPPS first as GE sees it and then as the Staff
9 sees it, then we'll see what questions the committee has.

10 MR. VILLA: Do you want me to begin?

11 MR. OKRENT: Why don't you?

12 MR. VILLA: The current status of UPPS is I think
13 something that you would call conceptual because we have not
14 created design details of the system. However, we have
15 defined the functions of the system to be, one, to
16 depressurize, to vent the containment and provide makeup water
17 to the core. And I think in brevity, that is the status of
18 the system.

19 Some questions about expanding its capability.
20 Yesterday it was asked if UPPS could be operated during a
21 fire, and since it uses the fire water, so to speak, for
22 water. The answer to that question is yes. The water supply
23 has the capability to deliver the maximum fire demand of water
24 to any compartment and still operate the UPPS system. But
25 that only relates to probably one fire, and depending, if it's

1 not the maximum demand like a large area in the reactor
2 building. Then if it's a place of small demand, there may be
3 two or three local fires or fires that are in compartments.
4 That's all I was going to say unless you have further
5 questions.

6 MR. OKRENT: Let's see what the Staff's view is.

7 MR. SCALETTI: The Staff's view is somewhat
8 similar. It is a conceptual design; the final design will
9 have to be provided later. The functions have been identified
10 and we will have to meet those functions to be able to carry
11 out those functions later on.

12 We have also identified that it probably should be
13 somewhat seismically hardened. Certain precautions taken when
14 the system is installed to ensure that you don't end up
15 putting air bottles in a non-Category 1 building, subjecting
16 them to an incapability to respond to these functions or to
17 carry out these functions if you have an earthquake or seismic
18 event.

19 So the details of the system are not provided yet;
20 they will come in later.

21 MR. OKRENT: Okay. If I can offer one or two
22 comments. When BNL reviewed PRA, they tried to estimate the
23 impact of UPPS on different sequences, and they found they had
24 insufficient information to do, let's say, a review up to the
25 usual standards. They had to make assumptions and make

1 estimates. I think that's a fair paraphrase of what they
2 said.

3 And the Staff, just in telling us that they hardened
4 seismically somewhat -- I don't know what that means; the
5 Staff said in the final plan there would have to be an UPPS
6 that met some kind of criteria. But at the moment, I would
7 say it's a little hard for me to know how, then, one will
8 judge what it was that's being agreed to now. That's one
9 person's view of -- well, the element of elusiveness, if you
10 want to put it, with regard to just what is UPPS.

11 Now, I don't know whether the committee has
12 questions on what we have heard or if they want to raise
13 questions along additional lines on UPPS.

14 MR. REMICK: I have a question. When would the UPPS
15 design be reviewed? Would this be as part of an amendment to
16 FDA or would this be at the CP stage of each unit?

17 MR. SCALETTI: It could be either. It's a GE
18 system. It would be incumbent on them to provide whatever
19 design UPPS has provided. It could be an amendment. Well, it
20 may not require an amendment. Well, it may require an
21 amendment to GESSAR, but it would be either GE or it could be
22 the utility/applicant including it in their application which
23 references GESSAR in the final design review. It would take
24 place then.

25 MR. REMICK: Has GE made any decision?

1 MR. SHERWOOD: Yes, sir. It's our intent now to
2 provide this design at the CP stage when we have an applicant.

3 MR. OKRENT: Other questions?

4 MR. WARD: I guess I don't quite understand then,
5 the FDA is approved without any commitment to UPPS?

6 MR. SHERWOOD: We have made the commitment to UPPS,
7 including -- as was stated by the Staff -- we call it a
8 hardened version. If that's the right way to describe it. So
9 we have committed to that. It's our desire to wait until we
10 actually have a customer who is interested in the system as to
11 where we go to the additional substantial expense of providing
12 the detailed design.

13 I guess if I may -- could I take a second and make a
14 couple of remarks?

15 MR. OKRENT: Sure.

16 MR. SHERWOOD: In terms of things that are working
17 with UPPS, I think we believe that with the PWR 6, the safety
18 of the plant is substantial in the sense of the PRA work that
19 we did as well as the confirming work by BNL. So therefore,
20 we believe -- and I think the Staff concurs -- that the PWR 6
21 MARK III meets all the regulations as they now exist without
22 UPPS. And indeed, that may be the safest plant offered in the
23 United States at this stage of the game.

24 But beyond that, we have decided to offer the UPPS
25 system as part of the severe accident effort and the severe

1 accident result as a way to even reduce the core damage
2 frequency. However, in light of the realities of the
3 situation in terms of future applicants for this plant, we
4 would propose not to go into the detailed design at this stage
5 of the game until we are assured that there would be an
6 applicant and a customer.

7 But we have indeed committed to the Staff to provide
8 that design when that indeed happens.

9 If I could just take another second, a similar case
10 exists with the hardened igniters for hydrogen control. It
11 would be very straightforward for us to provide a design, for
12 example, which would be an offshoot of one of our utility
13 designs. But again, there is the hydrogen control owners
14 group which is still going on and so forth. So our preferred
15 mode is to wait until those results are done and then design
16 it once, not design it twice.

17 MR. OKRENT: Are there any other questions at this
18 time on UPPS and its status?

19 MR. REMICK: Dave, I'm not sure I understand yet
20 what hardened means in this sense.

21 MR. OKRENT: Why don't you ask them to explain it to
22 you.

23 MR. REMICK: You said something about bottles. That
24 I think I can understand, but what else do you have in mind
25 when you talk about a hardened UPPS?

1 MR. SCALETTI: The bottles, the anchorage of the
2 bottles. We haven't gone into -- maybe Calvin Shu or
3 Rosenthal might have some comments associated with that.

4 MR. ROSENTHAL: Rather than requiring that the
5 system be IE or qualified to a certain level of seismic
6 acceleration, we thought it proper for this sort of system,
7 which is surely beyond design basis events, to take the system
8 and look at it when it is designed on a component basis; look
9 at what contributes to fragility of the system, what are the
10 weakest components; make a decision if some of those
11 components should be hardened or not and work our way up in
12 terms of seismic accelerations on a case by case, component by
13 component level rather than requiring some broad-scale
14 qualification which didn't take into account the judgments of,
15 let's say, the people who typically look at fragilities and
16 could say okay, that device is fine the way it is; this other
17 thnig needs something.

18 MR. REMICK: So this is in the same way as you're
19 talking about the igniter systems; you had some high
20 confidence it would work.

21 MR. ROSENTHAL: Yes, sir. But given our QA program,
22 I just don't see for these beyond design basis events, clearly
23 severe accident events, that we have to apply the same
24 standards of testing and paper trail. I think there is some
25 room for judgment and prudence. Let the fragility experts

1 look at the device and see what can be pragmatically done.

2 MR. REMICK: Any preconceived ideas that this would
3 be to .6g, twice the SSE? That that would be your criteria in
4 looking at it, in the case of the igniters?

5 MR. ROSENTHAL: The preconceived notion is that it
6 should be relatively easy to have confidence that that
7 equipment would survive because its diesel glow plugs --

8 MR. REMICK: I'm not arguing that case. I'm sorry I
9 wasn't clear. In the case of UPPS, is the Staff willing to
10 look for a hardened system that would withstand twice the SSE,
11 as apparently was the case --

12 MR. RUBIN: We have not established a hardened
13 criteria for the resistance of the system. What we have done
14 is required that the soft spots of the system be identified in
15 a rigorous manner by the applicant, by GE, when the system is
16 designed, and give us an opportunity at that point to make a
17 decision how hard it should be.

18 In the course of the BNL review, the likely soft
19 spots have been identified, but we have to admit that we are
20 shooting pretty much in the dark. It looks right now to be
21 such areas as the water supply, the air bottles, the primary
22 functions of the UPPS system. We certainly would expect those
23 to be looked at very carefully.

24 MR. EBERSOLE: Mr. Chairman, I had an interest in
25 the earthquake regime, when we can get back down to earth with

1 more realistic things like fires. We have an expensive
2 concept in design which we have told the plants over the years
3 to provide remote shutdown rooms to account primarily for
4 control room fires and other fires and focus on points where
5 we have the control ability of common, redundant systems.

6 This system here would provide capability to cope
7 with a fire anywhere if we pay a little attention to it. Yet,
8 I find it somewhat amusing, cynically perhaps, that we only
9 look at the seismic aspect.

10 That would be my complaint about it, the narrow
11 scope competence of the UPPS concept.

12 MR. OKRENT: Jesse, my guess as to why, in the last
13 month or two, the Staff has proposed the seismic hardening is
14 that according to their estimates of the PRA, seismic is an
15 important contributor and if UPPS has no seismic capability,
16 they can't use it. So they are trying to, I think, get it
17 useful in that series of sequences.

18 And if I can respond in a way to what Forrest was
19 asking, I think when they're talking about a .6g, it's not a
20 .6g SSE design basis with all of the code margins and so
21 forth; it's that you have -- well, perhaps I will put words in
22 their mouths -- a fairly high confidence that it will function
23 at .6g, and that means you have used up, you know, some of the
24 margins that are in the typical analysis.

25 MR. REMICK: I understand that. At times, I can

1 even applaud it. But then I get worried from a regulatory,
2 legal standpoint, is the Staff trying to require things twice
3 SSE? I don't know what the regulatory basis is. I think it's
4 great prudence, and I don't have a problem with it, but I do
5 have that legal, regulatory concern. Is it a ratchet underway
6 that we will hear about?

7 MR. OKRENT: If you look at what is evolving as the
8 opinion of -- I'll use the word, quote, "experts" who review
9 the seismic capability in plants, they are estimating a very
10 wide range in the fragility or capacity -- take your choice --
11 of components and structures and so forth, all of which are
12 nominally capable of meeting a certain SSE, ranging from some
13 that will take only perhaps three times the SSE to some that
14 will take twenty, okay, because there are other constraints on
15 design or whatever.

16 And if you are trying to increase the capability of
17 the plant that exists to earthquakes, I think they will not
18 recommend a uniform increase in capability across everything,
19 because that would be very inefficient and unnecessary. So
20 now the question is, what do you do?

21 MR. EBERSOLE: I hope you didn't mean I was saying
22 that we didn't need -- I would agree to sacrificing the
23 current fire protection system in its entirety, if we put a
24 properly competent UPPS system in place to cope with it.

25 MR. OKRENT: If you were the plant owner, would you?

1 MR. EBERSOLE: Yes, sir. But I would have a good
2 UPPS system.

3 MR. OKRENT: The frequency of fires in plants is
4 high enough.

5 MR. EBERSOLE: I'm talking about nuclear safety, not
6 the commercial aspect.

7 MR. OKRENT: Any other comments on the UPPS system
8 at this time, because I do want to get through this.

9 [No response.]

10 MR. OKRENT: The next item -- let's see if I can
11 reconstruct what it is, so we can cover it -- systems
12 interactions which could arise again during an earthquake by
13 failure of non-seismically qualified systems impacting on
14 seismic, such as the Diablo Canyon study, and in fact, which
15 studies are one of the principal -- five or six principal
16 recommendations of this expert seismic panel that the Staff
17 has. These are currently not part of the proposed Staff
18 requirements for GESSAR, unless there's been a change since
19 yesterday. And with regard to fires and their possibility of
20 them being close by an earthquake, that seems to be a
21 relatively unstudied question.

22 So we are calling the attention of the committee to
23 this, and now let the Staff or GE offer any comments that they
24 would like to on either of those two subjects.

25 MR. VILLA: Do I understand correctly that we are

1 discussion the issues yesterday about fire, the performance of
2 the fire protection system after an earthquake or deleterious
3 effects that can be caused by the failure of the fire
4 protection system?

5 MR. OKRENT: Well, in fact, you have pointed out
6 that the list --

7 MR. VILLA: It's not long enough.

8 MR. OKRENT: -- that I have shown here is too short
9 a list, and you have identified one or two things that we
10 talked about yesterday with no resolution.

11 MR. VILLA: Thank you.

12 What I have done in response to those two questions
13 is, check back with our designer, and I found a couple of
14 things that we didn't know yesterday, and one of them is that
15 the fire protection system throughout the plant is seismic,
16 and it is designed, including the sprinkler heads, to survive
17 an earthquake equivalent to the design basis for the entire
18 plant. It is not designed to function -- in other words, it's
19 not a safety-grade function; it's a safety-grade design, so
20 that components will not fall all over the plant, as we
21 discussed yesterday.

22 MR. MICHELSON: Does that include actuation, seismic
23 actuation?

24 MR. VILLA: In terms of design, it doesn't exclude
25 actuation; however, the experience is --

1 MR. MICHELSON: That was our problem yesterday.

2 MS. HANKINS: Actuation of the sprinkler system is
3 through thermal links.

4 MR. MICHELSON: In all cases?

5 MS. HANKINS: For all the deluging systems, for all
6 the sprinklers. Those sprinkler heads that have the links on
7 them are qualified to .3 SSE, so you would not expect
8 actuation.

9 MR. MICHELSON: What you really have to say is that
10 all the water systems in the plant are of that type. Then
11 it's a good statement. But you haven't told me that all the
12 water fire control systems are of the admission type with
13 therma. links at the nozzles, so that you have redundant
14 control over actuation.

15 If it's true, that's great.

16 MS. HANKINS: It's true of the sprinkler heads. The
17 manual hose systems -- there are no sprinklers in the ECCS.

18 MR. MICHELSON: There are no deluge systems in these
19 plants.

20 MS. HANKINS: In the ECCS rooms.

21 MR. MICHELSON: How about other areas of the plant
22 where there is vulnerable equipment, instruments, motor
23 control systems, whatever? You know, it's an equally good way
24 to get ECCS function.

25 MS. HANKINS: There are no sprinkler systems in the

1 electrical rooms either.

2 MR. MICHELSON: None at all.

3 MS. HANKINS: That's true.

4 MR. MICHELSON: There is no way water can get into
5 the electrical rooms from sprinkler systems that actuate, say,
6 above the electrical rooms, because they are all of the type
7 wherein it takes two failures before they would actuate.

8 MR. VILLA: That's correct.

9 MR. MICHELSON: Those are good words. If you put
10 them all together and tell it right, I would be happy as could
11 be.

12 MR. SHEWMON: Let me ask a question for
13 clarification.

14 When you say .3 SSE, you mean an SSE of .3, or .3
15 times the SSE?

16 MS. HANKINS: An SSE of .3g.

17 MR. EBERSOLE: Do you have some exclusion
18 requirements preventing massive and uncontrolled discharge of
19 CO2 into critical safety rooms, thereby blowing them up or
20 otherwise disrupting the proper performance of systems inside,
21 due to the fact that these control devices from tank farms is
22 not qualified?

23 We just heard Hope Creek this morning where they
24 threw out twelve tons.

25 MR. VILLA: We don't have someone here to answer the

1 question.

2 MR. EBERSOLE: You can do it by venting or QAing the
3 control devices or whatever.

4 MR. MICHELSON: The interface requirements by
5 whatever the utility supplies in terms of fire protection, are
6 they going to have to meet the same requirements that you
7 stated?

8 MR. VILLA: Certainly.

9 MR. MICHELSON: So you have prescribed interface
10 requirements on fire protection that, in essence, say there
11 will be no deluge systems, for instance.

12 MR. VILLA: We designed the entire system.

13 MR. MICHELSON: Outside balance-of-plant?

14 MR. VILLA: The only balance-of-plant that exists is
15 in the turbine --

16 MR. MICHELSON: Right. How is it prescribed?

17 MR. VILLA: It isn't.

18 MR. MICHELSON: You are sure, though, there is no
19 way there are interactions between inadvertent actuations
20 there and flooding above the compartments or whatever? That's
21 somehow an interface requirement?

22 MR. VILLA: It's a design requirement. In our part
23 of the building, the rooms are tight.

24 MR. MICHELSON: You put a barrier up against it?

25 MR. VILLA: And compartmentalized it.

1 MR. MICHELSON: Thank you.

2 MR. OKRENT: Does the Staff have any comments in
3 this area?

4 MR. SCALETTI: No, the Staff has none.

5 MR. VILLA: Could I make an additional comment? I
6 hope it doesn't drag things on further.

7 The other question that came along on this subject
8 was the interface requirements for non-seismic equipment, and
9 I have confirmed that we do establish interface requirements
10 for non-seismic equipment. In fact, in the nuclear island, we
11 designed the systems and analyze the systems or the
12 non-seismic components, so that they cannot cause significant
13 consequential effects on the emergency or safety-related
14 equipment.

15 MR. OKRENT: This is a GESSAR II requirement?

16 MR. VILLA: Yes.

17 MR. OKRENT: Is there someplace in the document
18 where you define it?

19 MR. VILLA: In the document structure, yes, but I
20 will have to find it for you.

21 MR. OKRENT: Would you let us know, because Staff
22 does not have that on its own, as far as I know.

23 MR. MICHELSON: You recall the reason we're asking
24 the question. How many non-seismic failures occur during an
25 earthquake? I'd expect in this document to find out what the

1 analysis assumptions should be.

2 MR. VILLA: Okay.

3 MR. OKRENT: Any other discussion on Item 11 at this
4 time?

5 [No response.]

6 MR. OKRENT: Let me come back to Item 3. I think
7 Mr. Michelson has had a chance -- I have not -- to scan the
8 document that Mr. Scaletti gave us.

9 This is the document, isn't it, Mr. Scaletti
10 (indicating)? Does it look about the right thickness?

11 MR. SCALETTI: About the right thickness.

12 MR. MICHELSON: I don't recall receiving this during
13 the subcommittee meeting. Isn't that what you said?

14 MR. SCALETTI: No, no. That is the proposed General
15 Electric amendment to GESSAR, covering the severe accident
16 interface requirements.

17 MR. MICHELSON: I thought from the chitchat earlier,
18 this was to be a list of the interface documents, but I
19 guess it's another list that we didn't get.

20 MR. SCALETTI: The section of that document which is
21 Table 1.9 will be amended for GESSAR II.

22 MR. MICHELSON: It doesn't list the interface
23 documents, though?

24 MR. SCALETTI: No.

25 MR. MICHELSON: I thought somehow we were finally

1 getting that list of interface documents. I guess that will
2 have to be some other time.

3 MR. OKRENT: Where in this is one to find your
4 quantitative requirements on balance-of-plant? Why don't you
5 look at this while we go ahead?

6 [Document handed to Mr. Villa.]

7 MR. OKRENT: Mr. Reed indicated he had a point he
8 wanted to raise.

9 MR. REED: I expect what we're working toward here
10 is perhaps a letter from the ACRS, and we try for consensus
11 letters, and we don't like to have additional comments. And I
12 am worried about past history with respect to something I did
13 30-some years ago.

14 Some 31 or '2 years ago, I took the position to a
15 number of utilities that the boiling water reactor concept
16 perhaps would have metallurgically and corrosion-wise many
17 problems because of the oxygen produced in the recirculating
18 fluid.

19 Now I have listened over the last 30 years to
20 numerous advances or steps backward with respect to the oxygen
21 issue and to the cracking, pipe cracking issue. And here we
22 are faced 30 years later -- I am faced 30 years later with
23 again perhaps taking a position, as I did with those
24 utilities, on whether or not I feel that the BWR and the
25 advanced GESSAR unit has overcome its environmental

1 metallurgical problem.

2 Now from what I heard this morning, it didn't sound
3 very much like it had, except for one last hope, perhaps, and
4 that is that hydrogen might be used as an inhibitor to try to
5 overcome the problem. It sounds to me, from what I heard this
6 morning, that the welding -- the heat treatment of the welds
7 and even the materials that have been placed into use are not
8 necessarily the solution.

9 Okay. So I have a dilemma. And I would like to
10 know what assurance the Staff can give me that this hope of
11 hydrogen will, in fact -- and GE can give me -- that this
12 issue of pipe cracking, which I think is a serious safety
13 issue, is, in fact, going to be solved, is solved, and what
14 proof do we have that it is?

15 MR. SHERWOOD: All the people who told us so, told
16 us they told us so thirty years ago. I didn't notice your
17 name on the list.

18 MR. REED: Let me say, that report was a
19 confidential report to eleven utility companies written by me,
20 following work on the borax reactor.

21 MR. SHERWOOD: We, around 19 -- or the end of 1969
22 or '70, when the pipe crack problem appeared, GE started a
23 fairly substantial study program, and then in the early '70s,
24 we augmented that by a major test program in-house, which, I
25 think many of you have seen the GE pipe test facilities where

1 we set up something like 30 to 50 cells for testing various
2 types of pipe to, number one, understand the phenomenon and,
3 number two, try to solve it. And that testing program
4 continued over something like five to eight years.

5 And as a result of that, it was determined what kind
6 of steels were more susceptible than others to intergranular
7 stress corrosion cracking. And out of that program came the
8 recommendation that the BWRs go to 316 nuclear-grade stainless
9 steel. That recommendation was discussed with the Commission
10 and with the Spence/Bush committee and a number of other
11 committees and so forth, and I think now is sort of, you know,
12 informally accepted in the BWR community.

13 Later, a number of BWRs began to actually change out
14 some of this piping to this 316 nuclear-grade stainless steel
15 as best they could, while others used other mitigations, such
16 as various types of heat treatment and so forth.

17 So we feel -- and I think people like the
18 Spence/Bush group and so forth feel like the problem, at least
19 in terms of selecting the right kind of steel, has been
20 corrected as a replacement of the 304 and so forth with 316.

21 MR. REED: Are you addressing the weld cracking
22 issue, or are you addressing the piping?

23 MR. SHERWOOD: I'm addressing the problem of
24 intergranular stress corrosion cracking, which is the culprit
25 for the change of a substantial amount of steel right now.

1 MR. REED: I guess I will have to ask Dr. Shewmon to
2 help me.

3 Didn't I hear this morning that the materials of the
4 welds were still cracking, and more evidence of more cracking
5 had been discovered?

6 MR. SHEWMON: Those were older plants, though, and
7 if they start with a new plant, they will put the material in
8 that he spoke of, which will be a step in the right
9 direction. They'll follow the PWR Owners Group practices on
10 water chemistry, which would be a big help. They probably
11 would use stress adjustment, as the Japanese have, and the
12 Japanese have largely overcome this problem on their own, and
13 they might then use hydrogen.

14 It seems to me, these three steps -- material
15 selection, water chemistry, whatever --

16 MR. SHERWOOD: That's correct. And hydrogen.

17 MR. SHEWMON: Stress adjustment.

18 MR. REED: We are convinced that the material
19 selection is now correct? Because haven't I heard that the
20 different types of Inconel welds, even the latest version of
21 Inconel weld, has cracked?

22 MR. SHEWMON: There is no car made so well that you
23 cannot tear it up if you drive it like a teenager. The same
24 thing with a piece of 18-8 stainless steel. If you put crappy
25 enough water and about enough stress on it, it will stress.

1 MR. REED: The point is, boiling water reactors
2 inherently make crappy water by producing oxygen.

3 MR. SHEWMON: Well, maybe, but my point is, they can
4 put a better material in it, and they are now agreed on water
5 chemistry procedures which will help, and the industry has
6 agreed on stress adjustment procedures which will help. And I
7 think, given those three elements, the chances of it standing
8 up well are very good.

9 MR. REED: Chances. What proof? I used the word
10 "proof."

11 MR. SHEWMON: You've got as much proof as a research
12 program in this country and other countries and operating
13 experience will give you.

14 MR. SHERWOOD: We have, I think, the proof at least
15 in the materials selection -- is tens of thousands of hours in
16 the test cells, which showed the comparison between the 304
17 and the 316 and so forth in the water environment.

18 MR. REED: These have been oxygenated loops,
19 potentially oxygenated?

20 MR. SHERWOOD: Yes.

21 MR. REED: Realistic field conditions?

22 MR. SHERWOOD: Yes.

23 MR. REED: Realistic stresses, and they are weld
24 coupons?

25 MR. SHERWOOD: Yes. In addition, as Dr. Shewmon

1 said, the industry is also, I think, paying more attention to
2 water chemistry than it had in the past, and we are now
3 talking to our customers, also as Dr. Shewmon said, about
4 adding hydrogen to the recirc system.

5 MR. REED: Will hydrogen work on the same basis as
6 it does in PWRs, the overpressures, et cetera? Will it be
7 effective?

8 MR. SHERWOOD: We are doing tests in Commonwealth
9 Edison and plan additional tests.

10 MR. REED: Are you putting specimens in the
11 Commonwealth Edison loops, let's say, of these materials in a
12 realistic condition?

13 MR. SHEWMON: They not only measure the corrosion
14 potential but the G.E. practice is they will have a test
15 specimen there and monitor where the cracks will stop growing
16 when they get the chemistry down.

17 MR. REED: These are stress realistic-type
18 specimens?

19 MR. SHEWMON: Yes. I say this from a corrosion
20 conference I was at earlier in the week where there were
21 people from their research lab or development lab who were
22 talking about what their practice was, so I speak through G.E.

23 MR. MICHELSON: My uneasiness comes from having
24 heard similar kinds of stories a few years back with quite
25 similar levels of optimism that this problem is now solved and

1 still getting bad experience from plants built after that
2 date.

3 MR. SHEWMON: We are probably growing old and
4 experienced.

5 MR. MICHELSON: I'm not trying to throw cold water
6 on it; I'm trying to make sure that it's understood that this
7 is yet to be really finally proof tested by building plants
8 and seeing how they go.

9 MR. SHERWOOD: I have hear that same story from my
10 engineer, but I think this time we have the test results --

11 MR. MICHELSON: If you are not getting closer, we
12 are all in trouble.

13 MR. KERR: We have a number of BWRs operating in
14 this country. Is Mr. Reed proposing that we do something
15 about those, or is it just that we don't want to build any
16 more unless there is an improvement?

17 MR. REED: I think we are going on a great new
18 venture here after 30 years of my stating in the record to
19 people that the BWR had a basic conceptual problem. Now I
20 might have to write to those eleven utilities and reverse
21 myself, saying that the metallurgical and materials and
22 corrosion and inhibitor situation has solved all this.

23 MR. SHEWMON: Glenn, would you write a letter on the
24 steam generators through PWRs too?

25 MR. REED: I wrote the same letter when the

1 Westinghouse people were here on steam generators 25 years
2 ago.

3 MR. WARD: Ten of those would probably tell you the
4 boiler is doing all right.

5 MR. REED: I don't think a single one would tell me
6 that their boilers are doing all right. They are having great
7 fun changing our piping.

8 MR. OKRENT: Glenn, I think this is about as much as
9 you are going to get on this.

10 MR. REED: Okay. I'm going to take the word of a
11 number of people here that this real conceptual big issue has
12 been solved.

13 MR. MICHELSON: Oh, no, nobody said that. I don't
14 think Dr. Shewmon said that. At least I hope.

15 MR. SHEWMON: The research people have solved it.
16 Whether the operating people have solved it or not yet remains
17 to be seen.

18 MR. REED: Remember, I'm an operator first, an
19 engineer second, and I get pretty tired of tough designs in
20 Corvairs being peddled to operators who are supposed to make
21 them work.

22 MR. SHERWOOD: We also have another solution to the
23 recirculation of cracking system. That is we are taking out
24 the recirculation pipes.

25 MR. OKRENT: That's not in GESSAR II.

1 MR. SHERWOOD: No, but that's essentially the final
2 solution.

3 MR. REED: I have got one last thrust. What the
4 vessels like, the reactor vessel? Keep in mind I have
5 observed boiling water reactor vessels with the interior
6 cladding cracked.

7 MR. VILLA: I believe the answer is stainless steel.

8 MR. WARD: Is it 304 or 316?

9 MR. MICHELSON: I think it's 308.

10 MR. OKRENT: If I could proceed to another item,
11 Mr. Ebersole had one or two broad points. We only have about
12 25 minutes left.

13 MR. EBERSOLE: I am personally convinced, to the
14 point where I would certainly consider writing an appendix to
15 the letter to say that this plant has such enormous potential
16 for improvement in reliability, not because it's not the
17 safest plant that I know, because I think it is. I'm just
18 trying to capitalize on its intrinsic physical characteristics
19 to, I might say, polish it off as the best thing I know how to
20 do, and without incurring too great a cost.

21 This causes me to converge to really just two
22 regions. I think we should legitimately and seriously and
23 with great care reconsider what we have got in this reactivity
24 control system with these two hockey sticks tied together with
25 this one-inch equalizing language which has a curious

1 capability to distribute the potential for solidifying the
2 dump volume, which it would not have if they were not so
3 tied, that line being present for the curious reason they want
4 to reach over and get the other set of level switches by
5 flooding them, too.

6 That sounds very funny to me, and I have never yet
7 been able to swallow the notion that we should close this
8 unfortunate dump volume to collect the fluid from the rod
9 discharges before we ascertain that the rods are home. So,
10 risking criticism by advancing a few little design
11 propositions here, I think that we should upgrade the
12 reactivity control system to eliminate the single dump volume
13 from configuration, which is now two hockey sticks tied
14 together with a small pipe, and instead provide a relatively
15 large dump line to the suppression pool from each hockey
16 stick, which are not tied together except at the suppression
17 pool level, and that we reexamine the logic such that we prove
18 that it would not or would be better to keep these lines over
19 until the rods are sent home.

20 In addition to doing this, these lines and the
21 valves pertaining thereto should be protected from easy access
22 to sabotage so that you can always ensure that you are going
23 to get an open flow path from the rods, and let's not hang out
24 this, as you might say, the fuse to the bomb. I think this
25 would entail reexamining individual rod seals and means to

1 preclude or tolerate the reverse flows that might occur at the
2 scram should you have continued leakage. You can always close
3 these open lines to the dump volume.

4 I am doing this to both, in my view, enhance the
5 reliability of the reactivity control system, which has been
6 steadily under criticism for 25 years or longer, and at the
7 same time I think apply a moderate bit of improvement to the
8 question of malpractice or, worse than that, an aspect to
9 defeating the shutdown system, the reactivity control system,
10 which, as I think we all know, if you do it well can lead to
11 spectacular consequences.

12 If we do this and then protect the electrical scram
13 network such that tampering or intrusion into the system will
14 virtually always initiate a trip system, I think we have gone
15 in a practical concept about as far as we can to upgrade the
16 system that shuts the reactor down. I am left, then, with a
17 system that is going to take care of it after it is shut down.

18 Again, in my view -- I will go back to the UPPS
19 system, which I think is a system very much of focused
20 simplicity to be able to manage virtually all of the accident
21 modes except the short-term cooling after LOCA. This would
22 include ability to cope with fires and obviate practically the
23 nuclear safety aspects of the remote shutdown system and all
24 of the expensive patches we put on to protect the system
25 against nuclear consequences of fire.

1 I don't want to in any sense of the word say that we
2 don't need commercial fire safety protection, but that is not
3 the costly part. The costly part is the nuclear safety
4 protection against fire and, for that matter, broken pipes and
5 lost ventilation and loss of the intake building and many
6 other things that you can find.

7 I think the UPPS system should as a part of this
8 design be defined sharply, certainly after detailed
9 examination, to cope with virtually all of these accident
10 modes except the short-term cooling after LOCA; that it should
11 be located within the containment to the extent possible with
12 an adjunct hardened building on the perimeter of the
13 containment and preferably linked to the containment only with
14 a channel or a vault at whatever it takes to get to the
15 containment, and if possible, that vault or hardened structure
16 be provided, as I understand some of the Swiss plants are, if
17 you can get it, with a drilled water well source underneath
18 it, which will provide, of course, a protected source of
19 water. That will not always be possible, so the alternative
20 to that is to provide a protected water supply with a fire
21 truck makeup.

22 To further sweeten the concept that I will always
23 get depressurization, I would sweeten or use diverse, probably
24 mechanical or hydraulic manual means to ensure the desired
25 depressurization. I would use manual hydraulic jacks or

1 mechanical means or whatever.

2 I have abhorred the present method of hot solenoids
3 being used to control pilot valves which then use air, which
4 in most cases is in a limited volume, but in this case,
5 fortunately, has an unlimited gas source to cause continued
6 function. Mainly I am after diversification of the
7 depressurization technique.

8 That is all I have to say except one other thought
9 that I would pass out. I think we should have a hard look
10 considering the configuration of the plant, in view of the
11 standing notion that we are going to have to deal with a
12 molten core, to look at the apparently not-too-extensive
13 changes that would be required to cause the current dry
14 drywell to be a wet drywell and thus provide the presence of
15 core coolant without any pumping.

16 I think this is consistent with the fact that I
17 think we all must agree, irrespective of the core condition,
18 we are going to try to cool it. I don't know of any means in
19 any practical context to say that the core is incandescent, we
20 are not going to cool it. I think we will always have to cool
21 it, and I am suggesting we cool it when it falls.

22 Finally, I find in examining the FSAR an extreme
23 sloppiness in the text -- the language, the narratives -- and
24 a general matching up of all the narrative support to the
25 design drawings is needed, including accurate representation

1 of the designs with much better definition and constraints in
2 the FSAR which we now have. At this time it is ambiguous and
3 incorrect in many, many places, and I use the FSAR as at least
4 the beginning point of examining the general concept and then
5 going into higher detail.

6 I am done.

7 MR. OKRENT: Are there questions or comments for
8 Mr. Ebersole?

9 [No response.]

10 Don't tell me I'm going to finish early.

11 [Laughter.]

12 MR. SHEWMON: You can declare a five-minute break
13 with the remaining three minutes.

14 MR. OKRENT: Are there any other comments anyone
15 wants to make?

16 MR. WYLIE: I had a little bit of the same problem
17 Carl had a little bit ago in interfaces. Maybe I missed it,
18 and I will just ask the question. I could not find anywhere in
19 the GESSAR a reference to the equipment grounding systems
20 being provided or lightning protection. Is that somewhere and
21 I missed it?

22 MR. VILLA: I believe the reason for that is that we
23 supplied the lightning system. The other system, I didn't
24 hear which one --

25 MR. WYLIE: I understood if you --

1 MR. VILLA: We design it and so naturally you
2 wouldn't see an interface requirement for it.

3 MR. WYLIE: I'm not talking about interface. You
4 described it somewhere if you were supplying it, wouldn't you?

5 MR. VILLA: Right.

6 MR. WYLIE: I couldn't find where you described it.

7 MR. VILLA: I'm not sure where it is either. What
8 was the other system?

9 MR. WYLIE: It is equipment and instrument grounding
10 systems and an interface.

11 MR. VILLA: Those we also design.

12 MR. WYLIE: To withstand lightning protection. But
13 I couldn't find where you described that.

14 MR. VILLA: I will have to look.

15 MR. WYLIE: Does the Staff know?

16 MR. SCALETTI: We are trying to find out. Someone
17 thought it would be in Section 7.

18 MR. WYLIE: It's not there. I looked.

19 MR. OKRENT: Let's not, then, if we don't have the
20 answer now, let's not spend 15 minutes trying to find it. We
21 will --

22 MR. WYLIE: I will just make one comment. There is
23 a description of how G.E. plans to ground the generator and
24 the power supplies they are supplying, but that does not cover
25 the equipment grounding and the ground system for the plant.

1 MR. OKRENT: There are some other things that they
2 are going to supply after today.

3 Glenn, you had another point?

4 MR. REED: In the barrage that I just leveled and
5 the rising to the occasion by many people to support the
6 metallurgical corrosion issue, I did not hear from the Staff,
7 to which the question was also addressed. Does Staff have a
8 comment?

9 MR. SCALETTI: The only comment the Staff has at
10 the moment is that through the course of the review of GESSAR
11 2, we had a problem with materials. G.E. agreed to change all
12 the materials to -- I mean the radioactive vessel material,
13 the pertinent material, to austenitic stainless steel required
14 by our current Reg Guides, and we found that acceptable. It
15 is written up in Sections 5 and 6 of the SER.

16 MR. SHEWMON: You don't have the stainless steel
17 pressure vessel.

18 MR. SCALETTI: No, no. I'm saying materials used
19 were not previously used before the Staff required this.

20 MR. REED: Is the hydrogen also in or out?

21 MR. SCALETTI: I can't answer that.

22 MR. OKRENT: By the way, Glenn, I have heard the
23 optimism about stress corrosion cracking enough times. Even
24 though I didn't write a letter 30 years ago, don't put me on
25 the side of those who reassured you.

1 MR. WYLIE: Let me make one other comment. In
2 Section 8 where the GESSAR references the feeders to the
3 electric systems and they say this is to be supplied by the
4 Applicant, there is an interface there that has to be worked
5 out because you have got the phasing to consider and other
6 considerations.

7 Now, is that something that is a negotiated thing
8 with the applicant and cannot be referenced here? I assume it
9 is.

10 MR. SCALETTI: Say your question again. I'm sorry.

11 MR. WYLIE: Well, the power supplies that are being
12 supplied to the nuclear island from the balance of plant, it
13 just simply says to be supplied by the Applicant. There is no
14 interface requirements placed on it, and that is something
15 that I can see is very difficult to do. You couldn't really
16 do it without knowing how you are going to design the rest of
17 the plant. It's got to be a negotiated thing.

18 MR. VILLA: There has to be an interface requirement
19 someplace.

20 MR. WYLIE: As far as the grounding system they will
21 be using on their power supplies and the phasing and this kind
22 of thing, it affects your transfers and the whole bit.

23 MR. EBERSOLE: A quick little thing. You know the
24 story of the Titanic is popular now. I sort of think my
25 little suggestions here are somewhat similar to what it must

1 have been, the argument with the MEAs, about the bulkheads
2 that didn't go to the deck because you had never hit, I think,
3 more than three compartments at a crack.

4 MR. OKRENT: We managed to run a few minutes beyond
5 3:15, Mr. Chairman, but I am going to propose you take back
6 the meeting and call a break.

7 MR. WARD: Okay. Let's take a break and return at
8 3:30 for the next item.

9 [Recess.]

10 Our next topic is Item 4 which is a report from the
11 ECCS subcommittee. I will give that.

12 At a recent subcommittee meeting on August 27th we
13 covered essentially four topics, and I will just review with
14 you briefly what was covered on three of these. And then on
15 the 4th topic, which is the resolution of unresolved safety
16 issue A-43 and the companion Reg Guide for containment
17 emergency sump performance, we will have a Staff presentation.

18 The first three topics, what I'll be talking about
19 is really in the nature of status reports, and the last, the
20 A-43 and the Reg Guide, it will be appropriate for the
21 committee to write a letter on the topic if after hearing the
22 presentation we believe that's the right thing to do.

23 The first of the three other topics was a review of
24 the status of the resolution of several concerns about
25 hydrodynamic LOCA loads in MARK I, II and III boiling water

1 reactor containments. This is an issue or a series of issues
2 that has been ongoing for several years.

3 At the present time, there is interaction primarily
4 between the boiling water reactor owners group for each
5 containment type essentially, and the Staff. At the present
6 time, many of the issues are resolved. Many of the individual
7 small issues are resolved but not yet all of them. Some of
8 the plant fixes are in place but not yet all of them.

9 The subcommittee expressed the desire to the Staff
10 to hear a little bit more in detail about some of the
11 resolutions and the analysis used to support the resolutions.
12 And we plan to provide the Staff with a series of specific
13 questions and have another meeting within the next month or
14 two months probably to satisfy ourselves that the resolution
15 of these issues is proceeding in a way that we think is
16 acceptable.

17 The second topic was a discussion of Generic Issue
18 61 which concerns the potential for or the failure of a relief
19 valve discharge line in the wetwell above the suppression
20 pool. This is an issue which was identified by our own Jesse
21 Ebersole, and the Staff has proceeded to the point where it
22 has classified it as a medium priority generic issue. And
23 this means that they are working on it and will develop a
24 resolution plan.

25 Jesse, do you want to say anything about that?

1 MR. EBERSOLE: I think it's well in hand and we
2 don't need to elaborate on it.

3 MR. WARD: Okay. The third topic was a discussion
4 of the feed and bleed capability at the Davis Besse plant.
5 Back about two, or it might even have been three years ago
6 when we had some extended discussions with the Staff on the
7 capability of the various PWR plants in the country to be
8 cooled by the feed and bleed process, they reported to us at
9 that time that the Davis Besse plant was somewhat unique, and
10 that among plants which had relief capability it was the
11 single one which did not have the system valve and pump
12 capacities to actually successfully feed and bleed at maximum
13 decay heat removal rates.

14 Since then, the Licensee had claimed that they
15 could, in fact, successfully feed and bleed immediately after
16 shutdown, and in fact, had procedures in place to perform the
17 feed and bleed operation.

18 The Staff has reevaluated the situation; they have
19 new information on the flow capacity of the pilot operated
20 relief valve, and they now agree with the Licensee that there
21 is at Davis Besse the capability to accomplish feed and bleed
22 cooling of the core.

23 Now there are some caveats with that. First of all,
24 as you know, feed and bleed is not a -- the capability to feed
25 and bleed is not a requirement for domestic plants, and in

1 fact, I think I can say no plants have the ability to feed and
2 bleed with all safety grade equipment. In most cases, the
3 feed comes from the high pressure injection pumps which are
4 safety grade, but the bleed comes from operation of the
5 PORV's, which are not entirely safety grade.

6 The Davis Besse situation is a little bit different
7 from that in that at normal pressures, the high pressure
8 injection pumps don't have enough discharge head to feed and
9 bleed. And the reason they can feed and bleed is they have
10 two charging pumps which do have sufficient output and which
11 have just enough capacity with the now-recognized larger
12 relief capacity of PORV to feed and bleed.

13 Now, the Licensee told us in the meeting on August
14 27th that while the charging pumps are not safety grade, they
15 are high reliability and rugged and have a lot of good
16 attributes. However, they are not safety grade, and in
17 particular, both pumps are needed and they are subject to a
18 common single failure which could prevent both pumps from
19 operating. So in that sense, the feed and bleed capability is
20 there; possibly it's not there in as reliable a form as it is
21 at many PWR's.

22 Mr. Reed?

23 MR. REED: I'm not so concerned about the fact that
24 the so-called high pressure safety injection pumps might not
25 deliver maximum pressure because they're probably in the 1500

1 or 1600 pound range. That doesn't bother me because in fact,
2 when you do open up bleed, pressures will reduce enough so
3 that they will inject.

4 The thing that bothers me I think is significant --

5 MR. WARD: Of course, the problem there is you have
6 to open up bleed before the system heats up to the point where
7 the saturation pressure temperature is above the pressure
8 of the discharge from the pumps.

9 MR. REED: Well, what's wrong with opening up bleed
10 as a first effort? I mean, that gets the pressure down.
11 You're interested in depressurization also in these events.

12 MR. WARD: I see nothing wrong with it, but it
13 happens that on June 9th it wasn't done.

14 MR. REED: The thing that bothers me and I think
15 what you're leading up to is Davis Besse now -- how good is it
16 now? The thing that bothers me is there's no redundancy in
17 the bleed valves. There's only a single trait, and with two
18 valves. And therefore, the opportunity for failure to open is
19 pretty good.

20 MR. KERR: Is there a particular reason it should
21 have been done on June whatever?

22 MR. WARD: That's sort of another subject. As it
23 turns out in retrospect, the decision not to feed and bleed,
24 at least in the narrow sense, was a correct decision. It
25 wasn't needed.

1 MR. KERR: I should hope.

2 MR. WARD: They were able to get the feedwater back
3 on. However, there's some question about -- I mean, the
4 procedures did call for the operator to begin feed and bleed
5 under the conditions he had, although there's some confusion
6 about his ability to accurately monitor the level in the steam
7 generator which is the key measurement.

8 He apparently had perhaps tens of minutes to make
9 the decision. Whether he knew that at the time was not all
10 that certain. But he didn't make it and he didn't have to
11 make it because the feedwater was returned.

12 MR. EBERSOLE: Dave, I would like to call out a
13 particular and very curious and disturbing aspect of the Davis
14 Besse designed. There seemed to be an almost willful
15 determination to avoid the use of electric-powered pump
16 feedwater, whereas most plants have either electric main
17 feedwater pumps or turbine-driven with condensate or
18 condensate booster pumps to get the water up to the suction.

19 This plant went to the trouble of having reduction
20 gear on the main turbine pump which then ran the speed down,
21 to run the condensate booster pump to get suction. Thus, it
22 was totally dependent on steam-driven main feedwater pumps
23 including the driving pump to get water to the suction,
24 nominally called a condensate booster pump.

25 Off in the distance there was this late coming and

1 poorly organized single, non-safety grade but still good but
2 disconnected, single motor left to get water in the plant,
3 other than the turbine pumps. That's almost a willful and
4 determined effort not to have the viability in the feedwater
5 function, which is a critical safety function.

6 I think the Staff should look hard at the balance of
7 plant like this as they do in A-17 -- GDC-17 -- for the
8 electric systems, look at the aspects of non-safety grade
9 equipment in the context of examining the challenge frequency
10 to safety systems.

11 MR. SIESS: Jesse, why do you think somebody would
12 be so foolish as to do that?

13 MR. EBERSOLE: I don't have the slightest idea
14 except some stubborn manager who loves steam.

15 MR. SIESS: I thought there was a certain amount of
16 encouragement from on high to use steam-driven pumps because
17 electricity wasn't very reliable.

18 MR. EBERSOLE: Gosh, that ain't true.

19 MR. SIESS: Every plant has steam-driven pumps.

20 MR. EBERSOLE: The Japanese use motors.

21 MR. SIESS: I'm talking about this country; I wasn't
22 going quite that high.

23 MR. EBERSOLE: Steam pumps look pretty in pictures
24 until you begin to hang the accessories on them.

25 MR. REED: I think when we talk about the

1 utilization of what I call a primary blowdown to remove
2 decay heat, we always use the term "bleed and feed" rather
3 than "feed and bleed." In my opinion, bleeding comes first.

4 MR. WARD: Some plants have -- in fact, I think the
5 other B&W plants -- have such high capacity, high pressure
6 injection pumps that discharge pressure of 2500 pounds or
7 something, that bleed and feed is possible -- I mean, feed and
8 bleed is possible.

9 MR. REED: You said it right; keep it bleed and
10 feed.

11 MR. WARD: But I agree, in many cases it has to be
12 the other.

13 MR. SIESS: Do they do it alternately? I sort of
14 had the idea they went on at the same time.

15 MR. WARD: In some cases you have to open up the
16 PORV's and bleed the system pressure down before you can begin
17 injection.

18 MR. SIESS: Once you begin injection you're doing it
19 simultaneously?

20 MR. WARD: Then it's steady state processing.

21 MR. SIESS: Bleed and feed rather than feed and
22 bleed.

23 MR. WARD: I think that's right.

24 Okay, if there's no further discussion on this we'll
25 go ahead to the next topic which is --

1 MR. REED: Dave, one thing. Where does everything
2 go from here? Davis Besse is shut down I assume. We have
3 seen a review. What is the status of the review now?

4 MR. WARD: I think we're going to hear more about
5 that later in a meeting. There is another step coming up. I
6 think we'll be participating in that. I'd like to just wait
7 until later in the meeting this week. It's a good point,
8 though.

9 Okay, the next topic which we covered at the
10 subcommittee meeting was a review of the Staff -- the NRR
11 proposed resolution of USIA 43, which includes a revised draft
12 Regulatory Guide 1.A2, and this is related to containment
13 emergency sump performance.

14 The subcommittee heard the presentation, and my
15 interpretation of the position of the subcommittee is that the
16 proposed resolution and the Reg Guide was satisfactory. But
17 it's a fairly important issue and we think that the full
18 committee should hear a report directly from the Staff on it.
19 So we are bringing that to you now.

20 If any of the other subcommittee members would like
21 to comment before Mr. Sirkiz begins his report, this is a good
22 opportunity.

23 MR. KERR: The subcommittee did get to the bottom of
24 the issue?

25 MR. WARD: Right, absolutely.

1 Okay, Mr. Sirkiz, if you would go ahead, please.

2 MR. SERKIZ: My name is Alex Serkiz. I'm with the
3 Generic Issues Branch, Division of Safety Technology, and the
4 Task Manager on USI A-43.

5 [Slide.]

6 Since I reviewed the Regulatory Guide 1.82 in some
7 detail with the subcommittee, the material I have provided
8 here is handout material, which is my slides also -- which are
9 my slides.

10 If you have questions, please stop me at that time.

11 I will dwell principally on where we stand in final
12 resolution.

13 [Slide.]

14 This is a very brief background, technical
15 background summary. We have concluded our technical findings
16 after about two and a half years of research and study, and
17 these are reported in Staff's NUREG-0897, Revision 1B. This
18 is a technical information document, which is one package of
19 four which will be published upon resolution of this issue.
20 Additions and modifications have been made to receive inputs
21 that were received during the "For Public Comment" period,
22 additional experiments as well as information received in from
23 the Owings-Corning Fiberglass Company and the Diamond Power
24 Company, who ran experiments or participated in experiments in
25 the HPR facility, where the inserted examples of their

1 insulation to see what would happen during a blowdown.

2 The results of those two findings are included as
3 the concluding appendices in NUREG-0897.

4 The principal finding I would bring to the
5 committee's attention relative to Reg Guide 1.82 is the need
6 to remove the 50 percent screen blockage criteria contain in
7 Section C.7 of the active Guide, and replacement of that with
8 the requirement to assess debris blockage potential on a
9 plant-specific basis as the principal change to the Regulatory
10 Guide.

11 The ACRS has been provided copies of this, and as I
12 indicated, just indicated, the Guide has been provided to you
13 in comparative form for ease of reference, as well as being
14 sent to the previous respondees who gave us input.

15 [Slide.]

16 Dwelling very briefly on what revisions were made to
17 the Reg Guide 1.82, we now discuss separately both boiling
18 water reactors and pressurized water reactors. The post-LOCA
19 recirculation capability is generic to both types of
20 reactors. As I just indicated, removal of the 50 percent
21 blockage criterion, and we also have revised the Reg Guide to
22 reflect some hydraulics findings and removal of the vortex
23 observations that previously had served as the basis to
24 quantify air jet. In fact, in many cases, this necessitated
25 in-plant tests.

1 The Appendix A in the Reg Guide provides
2 conservative guidelines for estimating the potential for air
3 ingestion. The fourth item in the Reg Guide has been revised
4 to require to an assessment of debris and particulate effects
5 on the pump bearings and seal assemblies. And that particular
6 item, Item 4, is an item that has been brought back to our
7 attention several times by the subcommittee.

8 [Slide.]

9 I would like to dwell briefly with you on the status
10 of implementation of the resolution. The Reg Guide has been
11 revised during the course of revising and resolving USI A-43
12 and reflects the technical findings. The implementation is
13 concurrent with the resolution of A-43.

14 What I mean by this is, there will be two regulatory
15 documents, the Regulatory Guide 1.82, Revision 1 and the
16 revision to the Standard Review Plan, Section 6.2.2, which
17 will be called Revision 4, which we will put down on paper and
18 make available to the community, the technical findings and
19 guidelines and criteria.

20 Our intent is to have the Reg Guide, Revision 1
21 become effective six months following the issuance date of the
22 Guide. It would apply to future CP applications and
23 preliminary design approvals that are docketed six months
24 after issuance and applications to final design approvals for
25 standardized plants that have not received approval at six

1 months following issuance of the Reg Guide.

2 [Slide.]

3 As we stand today, I can summarize the current
4 resolution position pretty much this way.

5 A regulatory analysis, a revised regulatory
6 analysis, has been prepared. The ACRS subcommittee that I
7 reviewed this issue with several weeks ago has been provided
8 copies of this. We briefed the subcommittee, and we did have
9 a meeting with the CRGR on September 9th to discuss the
10 proposed resolution. Agreement was reached to proceed with
11 the recommended actions with also an understanding that the
12 Reg Guide and SRP implementation wording would be revised to
13 more clearly reflect the intent of the regulatory changes.

14 [Slide.]

15 The revised implementation language is on this sheet
16 that has been provided to you, gentlemen, and it reads as
17 follows.

18 It would be applicable to the construction permit
19 applications and PDAs that are docketed six months after
20 issuance and applications for final design approvals for
21 standardized designs, which are intended for referencing in
22 future construction permit applications, which FDAs would not
23 have received approval at six months following issuance.

24 Our intent is to make the wording clear, that the
25 resolution of this USI will not be impacting plants under

1 construction.

2 [Slide.]

3 Page 6 of your handout is a bottomline summary of
4 exactly what our planned resolution is. We plan on issuing
5 the Staff's technical findings, to issue the SRP Section
6 6.2.2., called Revision 4, and Reg Guide 1.82, Revision 1.
7 These revisions reflect the technical findings. I have
8 covered with you the applicability of the regulatory
9 documents.

10 Item 3 is to issue a generic letter for information
11 only to all holders of an operating license or construction
12 permit, that outlines the safety concerns regarding potential
13 debris blockage and recirculation failure. It is suggested,
14 but not required, that the Licensees utilize the Reg Guide as
15 guidance for their conduct of 10 CFR 59 reviews for future
16 plant modifications involving replacement of insulation on
17 primary system piping or equipment.

18 If as a result of NRC Staff review of those Licensee
19 actions associated with this replacement, the Staff decides
20 that either SRP Section 6.2.2, Rev 4 or the Reg Guide criteria
21 should have been applied and the Staff seeks to impose these
22 criteria, then the NRC will treat such action as
23 plant-specific backfits pursuant to 10 CFR 50.59.

24 MR. MICHELSON: Could you explain in some other
25 words what that means?

1 MR. SERKIZ: I'll try.

2 If a major changeout of insulation is made, let's
3 say through the course of this conversation a plant that was
4 before predominantly reflective metallic goes to predominantly
5 fibers, that is the major change in the insulation. The
6 Licensee or the person with the construction permit then,
7 under the conditions or terms outlined in 10 CFR 50.59, has to
8 make a safety review to see if indeed there has been a
9 degradation, if you will, of some safety function implication
10 or whatever.

11 If, upon review of that particular 50.59 evaluation,
12 either the inspector for the Region or the Staff feels that
13 the revised Reg Guide, with the guidance, should have been
14 applied --

15 MR. MICHELSON: Should have been applied to the
16 changeout?

17 MR. SERKIZ: Yes, should have been applied to the
18 changeout. And the Staff then says, "Okay, we would like to
19 see your results in this fashion" -- I'm paraphrasing this in
20 my own words -- "then we will pursue it as a plant-specific
21 backfit action under 50.109.

22 MR. MICHELSON: Why is it a backfit when the
23 Applicant comes in and says, "I want to change something," and
24 the Staff says, "Fine, you can change it, but here are the
25 rules you will have to use if you wish to change to change

1 it?" How is that a backfit?

2 MR. SERKIZ: That's not what we're saying here.
3 50.59 does not deal with the backfits. As you know, 50.59
4 simply deals in a general way with looking at any change or
5 changeout to see if there is a degradation of some safety
6 function or some change relative to the original design
7 provided.

8 Since we have elected not to proceed with being
9 specific to apply it in terminology of backfit to every plant,
10 selected plants or whatever, we do feel that the guidance
11 provided, which is being provided in a generic letter, is good
12 advice, and we would have to pursue it if there were reasons
13 that were identified, that it warranted the application of
14 this evaluation criteria.

15 MR. MICHELSON: I'm trying to figure out what
16 backfit even has to do with this. When you've got something
17 already in operation, everybody is happy with it, and the
18 utility decides it would rather do something else, how can
19 anything involving that change ever be thought of as a
20 backfit. It's not a backfit at all.

21 MR. SERKIZ: I guess you can take that view. But
22 other people would take the view that it's a backfit from --
23 if the Staff says --

24 MR. MICHELSON: A backfit is when you tell the
25 Licensee that he's got to change something, I thought.

1 MR. SERKIZ: I grant you the point. We're not
2 telling him he's got to change anything. We are simply trying
3 to tie the loop down to a plant-specific action.

4 MR. REMICK: I see it slightly differently.
5 Although it's a Regulatory Guide and therefore doesn't have
6 requirements, if they impose this Regulatory Guide, Revised
7 Regulatory Guide, on the Applicant, then that is a change in
8 requirements. They have other requirements, too.

9 MR. MICHELSON: If the Applicant has decided to
10 change something --

11 MR. REMICK: But he has current criteria for that
12 now. He has current guidance.

13 MR. MICHELSON: He's already got approval for what
14 he's got.

15 MR. REMICK: That's right. And now you're giving
16 him new requirements.

17 MR. MICHELSON: No. He is saying, "I want to change
18 from what you already reviewed and approved. Here's what I
19 want to change to." And if you say, "Fine, as long as you do
20 this and this," anything you say isn't a backfit.

21 MR. WARD: Carl, when you say, "As long as you do
22 this and this," that has made it a backfit.

23 MR. MICHELSON: No, because he suggested a change.
24 Now what he does if he doesn't like what you suggest, and he
25 leaves it the way it is, there's no backfit.

1 MR. LEWIS: There is an official definition of
2 backfit nowadays within this agency.

3 MR. MICHELSON: That doesn't seem to fit that
4 definition either.

5 MR. LEWIS: I agree with you. It doesn't seem to
6 fit it.

7 MR. REED: Let's take the issue of a changeout of
8 steam generators on a PWR. I would assume insulation would
9 mostly be stripped, too.

10 MR. SERKIZ: Yes, sir.

11 MR. REED: This fits into what you're talking about,
12 doesn't it?

13 MR. SERKIZ: It can, yes.

14 MR. MICHELSON: Let's stick with insulation now.

15 MR. SERKIZ: Let me come back to this. The first
16 step is, under 50.59, they make an evaluation, okay. We were
17 not in a backfit mode or anything, okay.

18 What we are saying here is, following their
19 evaluation under 50.59, the Staff takes issue -- has a
20 difference of opinion, whatever way you want to phrase it,
21 okay, and then decides, okay, that the evaluation criteria in
22 this Regulatory Guide should have been applied -- we're not
23 making any specific requirements to apply this at this stage
24 to Reg Guide, okay; we feel it's good information, and we are
25 providing it to everybody with all the associated documents --

1 if the Staff then says, "Hey, you should have done this, or it
2 should have been," then the Staff is going to have to treat
3 this as a plant-specific backfit action.

4 Now the Staff is telling them, "Yes, you should have
5 applied this," and we will treat it as a plant-specific
6 backfit pursuant to the guidelines under 50.109.

7 MR. MICHELSON: What kind of review can the Staff do
8 without even using your new revisions of the Regulatory
9 Guide? They will do some kind of a common-sense review of
10 what is proposed, wouldn't they, if they didn't want to use
11 the Guide and therefore get into a backfit argument?

12 MR. SERKIZ: But that would never come about until
13 it was brought to somebody's attention, okay? Well, that's
14 maybe a wrong way to phrase it.

15 When there is a major changeout of insulation, the
16 utility, the Licensee should handle it by whatever means he's
17 handling it under here, okay, and he does this evaluation, his
18 safety evaluation.

19 Let's take a hypothetical case and say the Resident
20 Inspector looks at it and says, "Well, how come you didn't use
21 this?" And you get into one of these domino effects. At some
22 point for that particular plant and/or design, the Staff may
23 say, "Hey, you should have used this instead of intuitive
24 judgment."

25 All right. If the Staff should seek, then, to

1 utilize this and say, "You should have done it this way," all
2 I'm saying is, we will pursue it as a plant-specific backfit
3 under the guidelines set forth in this.

4 MR. REMICK: There's one problem I can see with
5 that. As I recall, Section 50.59, it basically says if you're
6 going to make a change, you must determine if it's an
7 unreviewed safety hazard. If it is an unreviewed safety
8 hazard, you must review it and submit it to the Staff. If you
9 determine it's not an unreviewed safety hazard, you can go
10 ahead and do it, and in your annual 50.59 Report to the
11 Commission, you indicate in there that you made that change.

12 It seems to me it would be possible for them to make
13 the change, put that in their annual report, and the Staff may
14 or may not catch it.

15 MR. SERKIZ: I would have to partially agree with
16 you because of that type of wording. I recently again
17 reviewed the 50.59 wording, and probably in some cases that
18 would be done that way.

19 What we're trying to do by issuing a generic letter
20 for information, we are indeed in that generic letter -- we
21 have also pointed out that we feel that you ought to take a
22 look at this in plants that would have small debris screen
23 areas, high flow rates, low MPSH margins, what you might term
24 good common engineering judgment. Lay it in front of them.
25 We provide to them the Staff's technical findings. The

1 Regulatory Guide itself has extensive appendices. It's
2 incumbent on them at that point to carry it out in whatever
3 way they carry out their 50.59s.

4 I guess in response to that question, since we've
5 had off and on a very open dialogue with two of the principal
6 insulation manufacturers, some do and some don't even now.

7 MR. OKRENT: I apologize if I ask a question that's
8 already been asked, but I'm trying to understand the
9 philosophy that says, if a Licensee makes a change in the
10 plant which the Staff finds is questionable, that it would be
11 treated as a backfit item. I think that's what the words
12 there say.

13 MR. MICHELSON: That's what it says.

14 MR. OKRENT: I don't understand that philosophy.

15 MR. REMICK: Dave, let me just try. I'm not saying
16 that I disagree with you, but I assume that the Licensee in
17 this case has his license, in that he is committed to meeting
18 certain regulatory requirements, the guidance of certain
19 Regulatory Guides or something equivalent.

20 MR. SERKIZ: Or the final design analysis.

21 MR. KERR: Before we go too far, I would suggest,
22 Professor Okrent did not say he wanted to understand it. He
23 just said he didn't.

24 MR. REMICK: Okay, thank you. I can see how you
25 could interpret it. If this is interpreted as changing the

1 requirements in midstream after the person has been licensed,
2 that could be considered a backfit.

3 MR. MICHELSON: Nothing is changing. If you just
4 leave the insulation the way it is, everybody's happy.

5 MR. REMICK: That's correct.

6 MR. MICHELSON: But he wants to change it now. I
7 think the Staff has a right to be unhappy about the change
8 without calling it a backfit.

9 MR. REMICK: But which regulatory guidance does he
10 follow?

11 MR. MICHELSON: At this point, I think you have to
12 use a case-by-case basis to see what you call it. In this
13 case, the insulation change was never prescribed in any
14 previous guidance, to my knowledge. Some of the problems of
15 insulation change were not previously prescribed.

16 MR. REMICK: He probably committed, though, to
17 meeting Reg Guide 1.82, Rev 0.

18 MR. MICHELSON: He's committed not to degrade the
19 safety of the plant by making the insulation change. In my
20 opinion, he has to show that he hasn't degraded the system.

21 MR. SERKIZ: Under 50.59, I think that's a
22 reasonable way of phrasing it.

23 MR. MICHELSON: You're on a case-by-case basis. The
24 Staff reviews his proposal. If they have problems with it, it
25 isn't a backfit. It just says, "Don't make the change."

1 MR. SERKIZ: The reason for inserting the backfit
2 here is, this particular section deals with plant-specific
3 backfits, and that's why I chose that phraseology.

4 If you want to look at backfit in the sense you're
5 discussing it, okay, I understand what you're saying. We will
6 treat this as plant-specific actions on follow-up under the
7 conditions or the guidelines set up by CFR 50.109.

8 MR. OKRENT: I don't understand what that last
9 statement means, because in there, there is talk about
10 significant effects on safety and so forth and so on, which
11 are a test for whether a backfit should be done. And I don't
12 see that the backfit provision applies.

13 MR. MICHELSON: I don't think it does, either.

14 MR. EBERSOLE: How long does this insulation last?

15 MR. SERKIZ: Some of it, where you uncover piping,
16 for example, for inspection during refueling and so on, on a
17 12 or 18-month period locally it's replaced. Larger sections
18 on steam generators and so on last considerably longer, if
19 you go into steam generator repair. So you're talking two or
20 four years generally before a complete change-out. I'm giving
21 you very general time periods.

22 MR. EBERSOLE: Of insulation?

23 MR. SERKIZ: Of insulation. Now plants, because of
24 containment peak loads in the last two or three years have
25 been switching to a fibrous type of mat type insulation

1 because of the better thermal insulating characteristics.

2 MR. WARD: Could I understand if a licensee now has
3 insulation that conforms with Reg Guide --

4 MR. SERKIZ: Whatever he's got there.

5 MR. WARD: -- 1.82, Revision 0, let's say he wants
6 to change it for some reason.

7 MR. SERKIZ: He can go ahead and change it.

8 MR. WARD: To conform to Reg Guide 1.82, Revision 0?

9 MR. SERKIZ: Yes. In other words, if he had Brand X
10 and he replaces it with Brand X that he got a new batch of in,
11 because by doing an identical replacement he would have made
12 no change under the conduct of the review here.

13 MR. MICHELSON: That's what you asked. He says same
14 brand. Just changing out. We're talking about changing from
15 metal to fibrous, I think.

16 MR. SERKIZ: The safety concern that we have drawn
17 attention to is the 50 percent blockage is not applicable to a
18 fibrous type insulation. So if the applicant changes to a
19 fibrous type to cut his containment heat load, he performs an
20 evaluation to see what degradation there might be to safety
21 systems, the design margins he had relative to his original
22 design, et cetera.

23 He performs this and puts it on file, if you will.
24 He submits it a year later, fine. This particular aspect here
25 is -- if the Staff looks at this, whether it's a year from now

1 or within weeks, and feels that he should have taken the
2 approach specified in the Reg Guide, it's going to follow the
3 rules that are laid down, just like we have rules laid down in
4 50.59, and is going to make a justification and go back, and
5 if we want him indeed to redo this, rejustify it, whatever, we
6 will handle this as a plant-specific action, and if 10 CFR
7 50.109 is called backfit or something akin to it.

8 MR. EBERSOLE: What if he has just the old plaster
9 up there; he just wants to keep patching it forever?

10 MR. SERKIZ: I guess he can keep doing that. If
11 it's just a local patch job, then it's a patch job.

12 MR. MICHELSON: The blockage question with fibrous
13 insulation was the pump bearing and seal cooling system
14 question. If he wishes to introduce fibrous insulation,
15 doesn't he have to now account for that particular question
16 before he's allowed to make the change? And it happens to be
17 in the new reg guide; it wasn't in the old one, but also,
18 simply an education, a learning process. He now knows.

19 So if he wants to make the change now, I think he
20 has to account for that problem and show that it's not a
21 problem.

22 MR. SERKIZ: I'll pick up on your term "account for
23 it" or make recognition for it. Under the methods or means
24 that 50.59 reviews are carried out. He does not have to come
25 in for permission to do this.

1 MR. MICHELSON: Yes. But when he does this
2 unreviewed safety question determination, he determines that
3 there is no unreviewed question. Now, if that's his answer
4 and it turns out he's wrong, then I don't know what the
5 process is.

6 MR. SERKIZ: Let's pick up on that just a minute.
7 Let's say you have a major changout, and his determination for
8 whatever reason says it's not a safety, the Staff says yes,
9 it is. We will simply pick it up as a plant-specific and then
10 pursue it to this courts of action.

11 MR. MICHELSON: Pursue it under the backfit rule?

12 MR. SERKIZ: Maybe backfit actions would be a better
13 term here.

14 MR. MICHELSON: I don't see that as a backfit
15 action. That's okay.

16 MR. KNIEL: We have elected not to backfit the
17 requirements to operating plants and plants under
18 construction. We've done that because we feel
19 deterministically the issue is sufficiently improbable and the
20 value impact is very marginal. So on that basis, we are not
21 requiring operating plants or plants under construction to
22 address this issue specifically. And on that basis, I think
23 it's consistent with that determination -- the determination
24 that if somebody does make a change and we do make such a
25 requirement, we are really adding a requirement that he wasn't

1 subjected to before, albeit he has changed the design of the
2 plant. But we're adding a requirement that he wasn't
3 previously subjected to, and that's the backfit.

4 I think there's an opening there, and I think even
5 though the Staff has to make the case I think we felt that was
6 a suitable compromise for this situation.

7 MR. OKRENT: How improbable does the Staff feel the
8 event is? He said it was sufficiently improbable that he
9 didn't have to backfit it.

10 MR. SERKIZ: Dave, the blockage frequency that we
11 calculated, for example, -- the blockage sequences we
12 calculated ranged at the upper end on the order of 3 times 10
13 to the minus 5, -- and I'll explain in a minute what drove
14 that up -- and down to numbers of 10 to the minus 6 and less.

15 The numbers, the plant conditions or design features
16 that drove it into the upper direction, since we studied it
17 parametrically, were driven by the fact that we analyzed plant
18 parameters where you had a 50-square foot debris screen area.
19 Couple this with 10,000 gpm recirculation flow rates and
20 available MPSH margin of one foot. If we took those three
21 combinations together you would calculate a blockage frequency
22 that high, and then we also assumed in the regulatory analysis
23 that this led to core melt.

24 MR. OKRENT: That was then what pipe break
25 frequency? Something larger --

1 MR. SERKIZ: We looked at large, medium and small.
2 We used the Salem plant as a pilot plant and analyzed all the
3 welds in a typical loop. Something like 255 welds in one loop
4 coming up to about 800 welds. So we did a weld size and
5 location distribution, and then also looked at it -- you have
6 to take it a step further because you would calculate so many
7 cubic feet of insulation debris being generated. We assumed
8 that got down to the debris screen, deposited uniformly, did
9 a calculation.

10 My reason for stating this is there were very
11 specific boundary conditions that drove that number high.
12 Conversely, if you looked at plants that had five foot or
13 more head screen areas of 200 square feet or more, flow areas
14 down to 60,000 HEPM, you'd be well below the 10 to the minus 6
15 frequency of blockage. That's the range.

16 MR. EBERSOLE: Let me ask a question. What if you
17 have an old boiler with a donut and the applicant or operator
18 has put tons of this plaster on piping inside, and you unleash
19 a few tons of this when you have some kind of a pipe fault,
20 and it proceeds to go to some of these critically vulnerable
21 pump journals and seals and grinds them to bits?

22 MR. SERKIZ: To get to that location it would have
23 to go down into the torus which -- say the blowdown forces
24 would take it down there. If you look at the local velocities
25 in the torus other than getting close to the RHR suction

1 strainers, let's say within several feet, the recirculation
2 velocities in the torus themselves are fairly low, less than
3 2/10 of a foot per second.

4 We've got experimental data on this stuff in
5 shredded form that says if you have recirculation velocities
6 less than 2/10 of a foot, it generally will not move or
7 transport. We made the assumption even in boilers that it
8 would transport and do some blockage, get similar blockage
9 numbers.

10 You could have some material transported, but in
11 terms of a gross transport, I would say that probably would
12 not occur.

13 MR. EBERSOLE: I don't think it takes a gross
14 transport to bind up the journals and seals. As a matter of
15 fact, this little hydroclone that we were talking about
16 earlier today for which there will be no insulation like this
17 to deal with may, if the plaster is at the right specific
18 gravity, tend to drive and thus concentrate the flow into the
19 seals and journals which can't tolerate it.

20 MR. SERKIZ: As I indicated before, you can have
21 degradation of the seals. We don't feel there will be a
22 significant degradation of the pump's operation or capacity to
23 keep pumping; in other words, moving fluid through there. I
24 do not disagree with you; you may not have a degradation of
25 the seal systems.

1 MR. EBERSOLE: I thought some of these were both
2 water lubricated and water cooled.

3 MR. SERKIZ: Some are, and we were not able to make
4 a clean generic case distinction, and we put some words very
5 specifically in the Reg Guide in the boiler section that
6 people should look at these, particularly on these multi-stage
7 bearing pumps.

8 MR. MICHELSON: But if they want to change out --
9 and that's really what we're talking about here -- they don't
10 have to consider this question at all because it was not in
11 the old reg guide.

12 MR. SERKIZ: Theoretically speaking, that's correct.

13 MR. MICHELSON: I think what you're saying is you do
14 not have to consider this question of the seal failures in
15 deciding whether or not you have an unresolved safety issue.
16 You know, the utility when he makes his unresolved safety
17 question determination does not have to include this issue
18 because it's not in the old reg guide.

19 MR. SERKIZ: If they elect to take that position I
20 guess they could. It would be a very shortsighted one.

21 MR. MICHELSON: It would be, but I think fully
22 acceptable from the regulatory viewpoint, isn't it, unless you
23 wish to raise it as a backfit issue.

24 MR. SERKIZ: Yes, sir.

25 MR. MICHELSON: I think that's what you're forced

1 into; if you want to fight it you must fight it as a backfit
2 issue.

3 MR. SERKIZ: That's correct, sir.

4 MR. MICHELSON: Thank you.

5 MR. WARD: I guess I am not sure where those of you
6 who are concerned with the definition here -- do you think the
7 reg guide and the resolution here is acceptable, or do you
8 have some change you want to suggest?

9 MR. MICHELSON: The reg guide is fine for future
10 plants. These funny words weren't a part of the reg guide, as
11 I recall.

12 MR. WARD: It's part of the resolution of the issue.

13 MR. MICHELSON: Not a part of the reg guide.

14 MR. SERKIZ: Funny words, whatever. The
15 implementation words --

16 MR. MICHELSON: No, no, the words that said that
17 this is treated as a backfit issue, et cetera, was that in the
18 reg guide? I missed it.

19 MR. SERKIZ: No, sir. These words that are in Item
20 3 are included in the generic letter that will be sent to all
21 people. That brings the issue to their attention.

22 MR. MICHELSON: It's those words I have problems
23 with; not the reg guide.

24 MR. MOELLER: It would not be proper simply to say
25 we will treat such an action pursuant to 10 CFR 50.109,

1 deleting "as a plant-specific backfit"?

2 MR. MICHELSON: That's playing with words.

3 MR. SERKIZ: That's what I tried to propose;
4 possibly substituting "backfit" with "plant-specific actions
5 pursuant to 10 CFR 50.109."

6 MR. MICHELSON: What needs to be said is it will be
7 treated on a case by case basis, which means in each case the
8 NRC will review and make a decision based on common sense, I
9 hope.

10 MR. MARK: Do you get notice of stuff being done
11 under 50.59, not necessarily until it's all finished?

12 MR. MICHELSON: No one reviewed safety questions

13 MR. SIESS: It goes in an annual report.

14 MR. SERKIZ: In today's climate, no utility in its
15 right mind is going to do anything without telling the NRC
16 about it, whether it's in the regulations or not.

17 MR. MARK: The resident inspector might notice.

18 MR. SERKIZ: I think where you might pick it up, the
19 resident inspector would pick this up and bring it either to
20 the Staff's attention at headquarters or regional attention.

21 MR. MICHELSON: My objection is treating it under
22 the backfit rule; I think it ought to be treated on a case by
23 case basis. That's my position.

24 MR. SERKIZ: We are treating it case by case, but we
25 also are subject to rules that we all live by, and the rules

1 are 50.109.

2 MR. MICHELSON: That's where we differ. I don't see
3 where that rule fits this situation. You haven't really
4 convinced me that there's an argument on why that rule fits
5 this situation. I've heard the arguments.

6 MR. WARD: The committee is going to have to write a
7 letter on this, and we have a question why. Karl, do you have
8 a suggested change to this informational letter?

9 MR. MICHELSON: I thought I made it very clear that
10 I don't think it applied to -- 50.109 even applies to a
11 situation like this, and that is just a design change proposed
12 by the utility and it's reviewed by the NRC but never ever
13 considered a backfit. When you consider it a backfit, there
14 are some special things that you have got to do. There's a
15 whole bunch of hoops you've got to jump through, and that
16 seems unnecessary or unwise in a case like this where we are
17 not asking the utility to change anything. He is wanting to
18 change something and it should be a common sense, case by case
19 examination of the problem. Which I thought was the way all
20 changes were handled anyway when a utility comes in with them.

21 MR. WARD: That's what the backfit rule is all
22 about, though, to provide a basis --

23 MR. MICHELSON: I think the rule is to protect the
24 utility from the NRC coming in and saying you can't do this,
25 can't do that, and make a change. No change is necessary

1 here. The utility decided, not NRC decided, that they wanted
2 to do something, and when they do they just tell the NRC what
3 it is and then a safety determination is made and the change
4 is authorized. Not under the backfit rule which has all these
5 extra little hoops to jump through.

6 MR. OKRENT: I think this is philosophically unsound
7 and the committee should reject that last clause and propose
8 words like Karl stated.

9 MR. MICHELSON: We can't reject it because it's not
10 a part of the guide.

11 MR. WARD: It's part of the resolution, though. We
12 can comment on that.

13 MR. SIESS: There's a different between telling them
14 what they must do, which is a backfit, and telling them what
15 they cannot do, which is what the Staff is doing. You can
16 change your insulation but you can't do that --

17 MR. MICHELSON: You can change your insulation but
18 you must do a safety determination based on some common sense
19 rules, which include for instance thinking about these little
20 cyclone separators which right now they don't even have to
21 think about. The Staff can only come back into the backfit
22 rule and make them think about it. It just seems irrational
23 to me.

24 MR. WARD: Karl, I would like to ask -- I have a
25 draft letter I'd like to give you a copy of and have you

1 doctor it up to your satisfaction and then we can discuss it
2 further in that form. Okay?

3 MR. MICHELSON: Okay.

4 MR. WARD: Mr. Serkiz, do you have anything else?

5 MR. SERKIZ: I have no further material.

6 MR. WARD: All right, thank you very much.

7 Let's go ahead with our next topic, which is primary
8 system integrity. I think we start out with a report from
9 Dr. Shewmon.

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mm/gjw
Take 20-1

1 MR. SHEWMON: Early in the year, we wrote a
2 letter saying that we thought the Staff had done enough
3 on leak before break that it could not be implemented in
4 situations in reactors, but that we would like to have the
5 opportunity to consider the implementation plans after these
6 had been developed by the Staff.

7 The Staff now wants to apply this to large
8 primary piping, where it would allow the removal of pipewhip
9 constraints which are an impediment to observation and
10 inspection of the piping and on the whole it looks like it
11 might be better if they were out.

12 For reasons I won't try to explain, the Staff
13 and the lawyers feel that this should be done in a change
14 to the standard design criteria for GDC No. 4, and so what
15 we have today is a presentation on this partly because of the
16 fact they are implementing leak before break on some piping
17 and partly because there has been an interest on why it is
18 we are coming into change GDC 4.

19 Without further introduction, I will let Bob
20 Bosnak go ahead and start the presentations.

21 MR. OKRENT: Are we talking about BWRs and PWRs?

22 MR. BOSNAK: Right now we are going to start
23 on PWRs.

24 MR. OKRENT: But the GDC is going to -- it is
25 general?

1 MR. BOSNAK: The narrow scope rule covers only
2 PWRs. The broad scope rule is intending to cover everything,
3 all items.

4 But that is not in place as yet.

5 MR. SHEWMON: The Staff has taken the position
6 that leak before break -- I hate to say it can't be applied
7 to PWRs, because we talked this morning as if it were
8 relevant there, but I think we will let him talk about it.

9 MR. BOSNAK: This is to give you a brief overview
10 of what we are going to try to cover.

11 I will start with the introduction as to where
12 we are, a little bit of history.

13 John O'Brien from research will get into where the
14 rules change stands. This is both the limited Dr. Okrent
15 mentioned and the broad scope rule.

16 Then, we are going to try to cover a little bit
17 of foreign practice. Ray Klacker was taken ill and won't
18 be here. I will get into what specific plant actions the
19 Staff has taken already on PWR main loop, and get into
20 arbitrary and immediate breaks, and finally two proposals
21 that we have had that we consider to be of interest and
22 we would like to get the Committee's reaction.

23 MR. EBERSOLE: Before we get out of the sight
24 of the previous topic, would a dynamic effect be considered
25 that of blowing off insulation from the pipe break?

1 MR. BOSNAK: Would you repeat the question?

2 MR. EBERSOLE: The topic we had just up had to
3 do with the dynamic effect that obtains the blowing away
4 of insulation off the piping. Is that a dynamic effect?

5 MR. BOSNAK: It is a dynamic effect. Foregone.
6 In other words, jets, they are gone.

7 MR. EBERSOLE: That is what knocks all this
8 insulation off that we just spent about an hour talking
9 about.

10 See how ambiguous this business gets?

11 MR. SHEWMON: Give him some time and you will
12 see what he is talking about.

13 MR. WARD: This ought to make you feel better, not
14 worse, Jesse.

15 (Slide.)

16 MR. BOSNAK: I would like to take you back to
17 your letter of June 14, 1983.

18 This is the last time that we met with the
19 Committee. We have had meetings with several of the full
20 Committee, but at that point, pulling time, and in your
21 letter you indicated that provided we can show that there
22 is a stable crack size by fracture mechanics techniques
23 and that leakage detection is available with sufficient
24 margin, before the crack becomes unstable and runs, then
25 we can go ahead.

1 And basically we had all of this in place at
2 that time for the PWR primary loop.

3 I am not talking about branch lines; I am talking
4 about the large diameter heavy PWR primary loop piping.

5 I think at the time we were here the work had
6 been done probabilistically and deterministically.

7 Probabilistically by Livermore for Westinghouse,
8 and by the Staff deterministically based on reports that
9 were submitted by Westinghouse.

10 And since then we have gone through several of
11 the other vendors on a vendor-by-vendor basis.

12 One of the caveats that we had, that we would
13 like to dwell on a little bit later is heavy component
14 support integrity.

15 You also ask that we advise the ACRS of any
16 regulation changes, and that is what we are going to do
17 today, and position for foreign regulatory bodies.

18 You did have another caveat which said before
19 you would send this to operating plants, there should be
20 some clear assurance of quality of design and construction,
21 so that if the history of your letter and where we think
22 we are with respect to going ahead from that point in time.

23 (Slide.)

24 When all the discussion started on leak before
25 break, the technical staff believed that it was possible

1 to move forward without making a change to the regulations.

2 There was much discussion on this back and forth,
3 and OELD had quite a bit of input.

4 They felt that there needed to be a change to
5 the regulations primarily because they felt if we did not do
6 it it would be a violation of Administrative Procedures Act
7 and that we were making rules by exemption.

8 So, they felt that a change was necessary. So
9 what the Staff is doing now, we will identify the plants to
10 which the schedule of exemptions apply.

11 Once we have determined that leak before break
12 performance has been established, and that is via mechanics
13 techniques, and again we are talking about PWR main loops
14 only, and leakage detection is in place, these are the things
15 that we can eliminate.

16 The dynamic loading effect. And we are talking
17 about pipewhip jet impingement, and again if we are talking
18 about jet impingement, we are talking about the fact that
19 it can affect insulation, to answer Dr. Ebersole's question.

20 A symmetric pressurization transients which was
21 USIA2, that remember started back in 1975, when one of the
22 vendors came in -- in fact, it was on North Anna -- and
23 indicated as far as their calculational techniques were
24 concerned, that they now were aware of pressurization
25 transients that gave us a Delta-P within the reactor vessel,

1 and a Delta-P outside of the reactor vessel in the associated
2 cavity. On those forces, they were very short dynamic
3 forces that were not considered before. That is how we
4 started on the unresolved safety issue A2.

5 Break associated dynamic transients and unbroken
6 portions of the main loop and connected branch lines.

7 Those are the things that can be eliminated.
8 Now, what cannot be changed, and I think the key here is
9 what we are trying to do is we are trying to get rid of
10 whip restraint structures and jet impingement barriers.
11 Everyone I believe feels that they may decrease safety
12 rather than improve safety.

13 MR. OKRENT: Who is the, 'everyone,' when you
14 say everyone?

15 MR. BOSNAK: Most of the Staff, the technical
16 staff.

17 MR. OKRENT: I just wanted to know.

18 MR. BOSNAK: All of the peer review groups
19 that were involved in the piping review committee.

20 MR. OKRENT: I was trying to understand.

21 MR. BOSNAK: We have heard of no one that has
22 said that whip restraint structure and jet impingement
23 barriers, per se, are going to increase safety and
24 improve safety.

25 These are from both deterministic and probabilistic

1 studies.

2 MR. OKRENT: Are you including foreign groups
3 in that statement?

4 MR. BOSNAK: Certain foreign groups, as well as
5 -- and John O'Brien will get to which ones, and where.

6 Particularly, the Germans and the Italians.
7 Others are considering this same approach. Again, it is
8 on a limited basis going forward only with the PWR main loop
9 where you feel that there is a very good basis that we are
10 not going to have a guillotine, instantaneous guillotine
11 double-ended break.

12 MR. MICHELSON: I am having a real problem of
13 making sure I understand what you are considering . You are
14 removing the dynamic unloading effects. What size breaks
15 are you now postulating, since you have eliminated the kind
16 that develop jets -- I guess that eliminates all splits.

17 MR. BOSNAK: If you have eliminated in the loop,
18 you still have the branch lines. The branch lines have
19 not been eliminated.

20 MR. MICHELSON: Let's stick with the main loop
21 where you are making your assumptions. In the main loop
22 you are not going to get anything but small leaks, is that
23 correct?

24 MR. BOSNAK: In the main loop you are no going
25 to get a large break.

1 However --

2 MR. MICHELSON: Wait a minute then. How big a
3 break are you going to get is my question.

4 MR. BOSNAK: We have not gotten into the other
5 area --

6 MR. MICHELSON: Just on the main loop now, now
7 on the branch line. From the main loop, what is the
8 biggest break you are going to get, or is it just a leak?

9 MR. BOSNAK: It is going to be a leak and it
10 is of the order of -- to be able to detect 1 gpm within
11 one hour.

12 MR. MICHELSON: It is just a drip, in other
13 words.

14 MR. SHEWMON: You have to be a real operating
15 engineer to consider a gallon a minute a drip. I guess
16 if you are an engineer you do.

17 MR. MICHELSON: You are eliminating all breaks
18 on the main line except for these little dribbles.

19 MR. BOSNAK: That is correct, with the exception of
20 the branch line.

21 MR. MICHELSON: But you are not going to go back
22 and change any of the ECCS design even though there is no
23 other pipe anywhere as big as the main loop, and that was
24 the basis for selecting the main loop.

25 MR. BOSNAK: We are not changing ECCS. We are

1 not changing equipment qualification.

2 MR. MICHELSON: What is your rationale for not
3 changing these other things, since you have eliminated the
4 breaks that were the basis for the ECCS.

5 MR. BOSNAK: The rationale might be defense in
6 depth.

7 MR. MICHELSON: On that rationale, I might want
8 to ask some other -- you know it might be nice to assume
9 jets and bigger breaks for defense in depth, too.

10 MR. BOSNAK: Again, we are only talking about the
11 primary loop. There are other things that can provide
12 sources of leaks.

13 You have manhole covers, you have various things
14 that can provide sources of leaks, so rather than get into
15 all sorts of mechanistic scenarios, we are staying with
16 the non-mechanistic, if you like, scenario which says you
17 are not changing containment designs.

18 You are not going to change ECCS and you are not
19 going to change the equipment qualification, the profile.

20 MR. REED: Let's for a minute hit something related
21 to containment design, and see whether that would be changed.
22 There is a great deal of argument going on about Appendix J,
23 and full pressure containment testing.

24 If you eliminate these large breaks, the
25 accident analysis will generally probably show that you

1 don't achieve full pressure. You are going to achieve
2 part pressure.

3 MR. BOSNAK: That is correct, but we are not
4 changing on that basis.

5 MR. REED: You are not going to allow Appendix J
6 testing to stay at pipe pressure testing?

7 MR. BOSNAK: The answer is we are making no
8 change.

9 MR. REED : That would seem that it should be
10 changed.

11 MR. BOSNAK: We have gotten comments -- by the
12 way, the rule was published I believe the first of July and
13 we have gotten eleven comments so far.

14 There was a comment on doing something with the
15 environmental profile. That was a comment that was received.
16 It would be along the same lines that you are suggesting
17 I believe, but that is where we are with respect to how we
18 are implementing on the schedule basis the exemptions for
19 the various plants.

20

End 20.
(Joe W was
typist.)

21

22

23

24

25

#21-SueW

1 MR. OKRENT: Excuse me. Are you going to
2 discuss the quality, how would you assess the quality
3 at the plants? Remember that item in the ACRS letter?

4 MR. BOSNAK: Correct.

5 MR. OKRENT: Were you going to discuss that?

6 MR. BOSNAK: Right now we are staying with
7 the primary loop.

8 MR. OKRENT: That's right. I'm talking about
9 the primary loop.

10 MR. BOSNAK: We are saying that the primary
11 loop -- I think what -- the way we interpreted the ACRS
12 letter was that if we went into older plants where the
13 quality of construction, the chance for perhaps some
14 errors was not as good as what we had today, that we
15 should make sure that we are satisfied with the quality
16 of construction.

17 That's the way we interpreted that letter.

18 MR. OKRENT: And I'm trying to ascertain with
19 the primary loop, are you trying to ascertain the quality
20 of the primary loop?

21 MR. BOSNAK: On the basis of our experience
22 with the primary loop, we don't feel that there are
23 quality problems when we are -- again discussing the loop.
24 When you start getting into other areas, it becomes more
25 of a problem.

#21-2-SueW

1 MR. OKRENT: What is your basis for -- let's
2 take a plant like San Onofre 1 or Connecticut Yankee,
3 which I think was designed and fabricated for -- we started
4 instituting much of the improved quality in primary systems
5 and in-service inspection and pre-service -- you know,
6 different kinds of inspection, pre-service and so forth
7 where there may have been less control on welds, material
8 in the field, et cetera, et cetera, how do you ascertain
9 the quality of the primary loop?

10 Well, I don't even know if all welds in the
11 primary system are inspectable for some of the older plants,
12 whether they would be, or the newer ones.

13 MR. BOSNAK: Again, we do have whatever as-
14 surance that you have from the factory mechanics bases
15 that given that you have a crack or a flaw, that is it
16 going to be able to propagate.

17 MR. OKRENT: But they assume, for example, in
18 fracture mechanics they have to assume some material
19 properties.

20 MR. BOSNAK: Correct.

21 MR. OKRENT: If there wasn't good control on
22 weld rod, they don't know what the material is.

23 MR. BOSNAK: Even so, the basis is that even
24 if you have all of those uncertainties you are going to
25 get a leak before you have a break.

#21-3-SueW 1

MR. OKRENT: You have to show me that basis.

2

MR. SIESS: Have you got a couple of days to

3

spare?

4

MR. BOSNAK: That again is based on the

5

deterministic work that was done, the probability of having

6

a break and the probabilistic work that was done. You

7

are talking about -- again if you are talking about direct

8

effects, you are talking about ten to the minus thirteenth

9

for a break, the probability of having such a break.

10

And even if there were several low orders of

11

magnitude of uncertainty on that, it still represents

12

an almost incredible event.

13

MR. OKRENT: There is a well known concept in

14

civil engineering that bridges and structures will never

15

fail if you analyze them probabilistically.

16

The difficulty is when they fail it's due to

17

something that wasn't in the probabilistic analysis, and

18

they do fail from time to time.

19

MR. SIESS: I disagree with the first proposition,

20

not the second.

21

MR. BOSNAK: We are saying the assurance is

22

here for these systems now that we are talking about. If

23

they are going to leak --

24

MR. SIESS: They will fail but they won't

25

fail catastrophically.

#21-4-SueW

1 MR. BOSNAK: Even if you wanted to get into
2 a failure scenario, how can we be sure that the massive
3 steel structures that we have in there are put in at the
4 right place?

5 MR. OKRENT: I'm looking at the Staff's logic,
6 and I'm looking at the specific comment that the ACRS
7 letter had concerning older plants.

8 And I have not heard anything that you have done
9 to assess why the older plants are okay. For example, I
10 have heard people mention possible troubles --

11 MR. BOSNAK: The older plants are not going to
12 be taking anything out. The older plants are going to stay
13 with what they have.

14 The older plants, and this is USI A-2 -- and
15 aren't going to have to put in additional steel to take
16 care of the asymmetric pressure loads. That is what is
17 happening with the older plants.

18 The older plants are there. We are not going
19 to take anything out. The ones that are of the vintage
20 that you are talking about in the Westinghouse Owners
21 Group are just not going to have to put in additional
22 steel for the asymmetric pressure transients, A-2.

23 MR. OKRENT: I have no objection to their not
24 putting in additional steel for the asymmetric --

25 MR. SHEWMAN: What will come out of plants?

#21-5-SueW 1

MR. OKRENT: What vintage will you start
taking things out?

2

3

MR. BOSNAK: We are talking about the Westinghouse
A-2 facilities. There are sixteen plants.

4

5

We said that the review is complete for Cook 1
and 2, Ginna and Point Beach. The other two facilities
have not responded as yet, probably because they are wait-
ing for the rule to go through.

6

7

8

9

(Slide.)

10

What they have to do now if they wanted to come
in at the present time would be to come in with a value
impact type study.

11

12

13

MR. OKRENT: And must Ginna and Point Beach
come right into the next wave after San Onofre 1 and
Connecticut Yankee, that happens to be good timing.

14

15

16

MR. BOSNAK: We are talking again about -- we
are talking about Issue A-2. The newer plants -- and
that's what I want, as you get down to -- these are the
NTOLs. We are talking about a different situation.

17

18

19

20

So you are kind of mixing up apples and oranges
to a certain degree. The old plants are not -- we are not
proposing at the present time to do anything with respect
to taking things out.

21

22

23

24

What they really need is, as far as that Issue
A-2 is concerned, asymmetric pressure transient, to get

25

#21-6-SueW 1

2 rid of that particular problem and have to do it. That's
3 what we are talking about.

4

5 Now, for instance, the combustion engineering
6 plants, the old plants, in order to get rid of it they
7 can take advantage of the decoupling of SSE and LOCA.
8 The B&W plants do not need either. The old plants, in
9 order to resolve the Issue A-2, they do not need either
10 because they can handle both events.

11

12 Now, down into the combustion engineering these
13 are the newer plants. The Staff has completed its review,
14 and it was done on Palo Verde. It was done recently with
15 a letter to CE not too long ago.

16

17 B&W review is underway and GESSAR II review
18 is underway. They have not been completed.

19

20 MR. EBERSOLE: Wait a minute. You said GESSAR
21 II. I thought this was applying just to PWRs without
22 stress corrosion cracking problem.

23

24 MR. BOSNAK: This is for a situation which
25 theoretically you don't have stress corrosion cracking
because you are starting out with nuclear grade material.

26

27 MR. EBERSOLE: Okay. The premise is that pipe
28 is just as good as a BWR.

29

30 MR. BOSNAK: Obviously this rule which covers
31 only PWR main loops would not apply to GESSAR II. But it
32 was put up here to be complete.

33

34

#21-7-SueW

1 MR. EBERSOLE: You are talking about new GE
2 loops?

3 MR. BOSNAK: That's correct, when it's done.
4 But the work is still under review.

5 MR. SHEWMAN: Where will the pipe -- where will the
6 pipe whip restrain question come up? Is that with this
7 next group of plants you've got?

8 MR. BOSNAK: Yes. We are talking about now the
9 NTOLs. I think all of these, some of them have already
10 started operating.

11 The exemptions which were granted, and we
12 checked here before we came down, I think these are correct.
13 This indicates that the technical work is complete, that
14 the Staff, the Technical Staff, has gone through on their
15 fracture mechanics approach and is in agreement that they
16 have demonstrated leak before break performance.

17 This would be the formal exemption that is given
18 not to comply with GDC 4 with respect to, in this case we
19 are talking about only jet impingement shields. In other
20 cases, it would be if they haven't shimmed up for the
21 pipe for a pipe whip restraint they might not have to do
22 that.

23 The scheduled exemptions were given for a
24 period of time I think to the eighteenth month after the
25 first refueling I believe. Is that right? Second refueling.

#21-8-SueW

1 So that by that time, ELD believes that the
2 rule should be in place, that then they can go ahead and
3 remove other things if they so desire.

4 But currently as they receive their license,
5 there is a specific request made for exemption. In some
6 plants it was rather quite specific as you see here.
7 So things were installed and there was nothing that was
8 removed and these were then all of the NTOLs that have
9 applied and been granted exemptions.

10 Now there are other applications that we did
11 want to bring to your attention. Prairie Island and Indian
12 Point, and for those they are different than these obviously.

13 The review is underway. We have gotten several
14 submissions from particularly the PWR owners to carry this
15 thing forward beyond main loop, to go to things like
16 pressurizer surge lines, accumulator injection lines and
17 other areas. Also, Nine Mile has requested secondary lines.

18 And all of these are -- there is no action
19 taking place on them. They are just pending.

20 MR. OKRENT: At some point, are you going to
21 tell us what it is that you are proposing to do in a
22 generic way? What you are proposing to permit in a
23 generic way?

24 MR. BOSNAK: When you say generic, do you mean
25 across the board, not just -- in other words, you would like

#21-9-SueW 1

2 to know the difference between the limited scope and the
3 broad scope?

4 MR. OKRENT: No. I mean in the limited scope.

5 MR. BOSNAK: I guess the question is, what do
6 you mean by generic?

7 MR. OKRENT: It's applicable to a class of
8 plant, all PWRs or all PWRs built after -- according to
9 a certain ASME Code. Okay. That makes it generic. That
10 applies to a class of plants.

11 MR. BOSNAK: The limited scope rule is applicable
12 to all PWR main loops.

13 MR. OKRENT: What does this permit?

14 MR. BOSNAK: It would permit if they can
15 demonstrate leak before break performance that you could
16 eliminate all of the things that I had on the previous
17 slide. We are talking about basically jet impingement
18 and pipe whip restraint.

19 MR. SIESS: Some pipe whip restraints simply
20 limit movement. That is, they have appearance.

21 MR. BOSNAK: That's correct.

22 MR. SIESS: Are there also pipewhip restraints
23 that have snubbers?

24 MR. BOSNAK: There are snubbers that are
25 placed in a line to take care of dynamic loads. And to
that sense --

#21-10-SueW

MR. SIESS: On the last page, it mentions
snubbers at Crystal River.

MR. BOSNAK: I'm going to get to that.

MR. SIESS: Are those pipewhip restraints, or
are those snubbers for seismic? When you say dynamic
loads seismic --

MR. BOSNAK: They are there for several
purposes. They are there for seismic and pipe break
loads.

However, the larger load of all the governing
load is the pipe break load.

MR. SIESS: Okay.

MR. BOSNAK: I think maybe at this point, it
would be good to have John O'Brien come up and get into
the status of the rule change and what is going on with
respect to foreign governments.

MR. REED: I think I have one concern. I'm
certainly convinced after following PWR main loop per-
formance and testing for cracking and all these kind of
things that there isn't a particular problem with some
fracture of PWRs.

But you keep mentioning BWRs, and I am worried
that by osmosis this might leak over into the BWR field --

MR. SHEWMON: Let's keep that in our mind,
this is a five minute introduction that has taken half an

21-11-SueW

1 hour so far.

2 MR. BOSNAK: That's why I wanted to get John
3 up here next to discuss the broad scope rule, where it
4 stands and what is going on.

END #21

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1 [Slide.]

2 MR. O'BRIEN: I want to show you some pipewhip
3 restraints on some very large diameter pipes. There is an H
4 section here, these steel straps. There is an H member coming
5 up that way and some connecting structure between the two
6 pipes. There is similar orientation over here. The black
7 small diameter members are not part of pipewhip restraint,
8 but that gives an illustration of what a pipewhip restraint
9 is.

10 We have some crushable high cone here. This is an
11 attempt to illustrate the clutter that results from the use of
12 pipewhip restraints.

13 [Slide.]

14 We have two rules on the same subject. The limited
15 scope rule is limited in many ways. It is limited in that it
16 only addresses the main loops of PWRS and also limited in that
17 only dynamic effects are discussed. That is the only change
18 anticipated, and we are shooting to get it in final form some
19 time in January.

20 The broad scope rule is a slow-moving rule. That's
21 an optimistic schedule right there, January 1986 for the
22 proposal and June for the final. Bob said we got eleven
23 comments. It's up to 19 right now. All the comments support
24 the rule, or the intent of the rule.

25 [Slide.]

1 The comments come from utilities and vendors, but
2 there is no opposition to the rule. These are some of the
3 issues raised in the comments, like we were silent in the
4 proposed limited scope rule on environmental qualification. A
5 lot of the commenters told us we should now include
6 environmental qualification, ECCS and containments. In the
7 new broad scope rule, which you may not have seen, we said
8 this rule introduces an inconsistency in the regulation by
9 only excluding dynamic effects while ignoring other effects,
10 especially with pipe rupture. We make a commitment to study
11 whether fracture mechanics should be applied to ECCS
12 containment and environmental qualification, but we don't
13 indicate when and by whom, but we are going to live with this
14 inconsistency right now.

15 Only the ACRS was troubled by the definition of the
16 primary system. Everybody else seemed to know it, but we
17 thought we would throw it in. And this is a hot issue
18 People want to modify heavy component supports. They want to
19 eliminate dynamic effects of postulated pipe ruptures as they
20 impact heavy component supports.

21 A careful reading of the proposed limited rule says
22 heavy component support designs are not to be changed. We got
23 a lot of comments asking us to do that. I don't know what the
24 resolution of these issues is, by the way. These are just the
25 issues.

1 MR. SHEWMON: Is there anything that is removable?
2 If you have to take anything out to inspect it, it is nice if
3 you don't have to put it back in and then take it out again
4 the next time. But the heavy component supports for a
5 licensed plant are there, aren't they?

6 MR. O'BRIEN: No, they are mostly huge numbers.
7 There is more than one utility that is affected.

8 MR. SHEWMON: You are saying the snubber is the
9 support.

10 MR. O'BRIEN: Yes. It's a heavy component support,
11 huge numbers.

12 MR. SHEWMON: I think of it as a shock
13 absorber. Nothing you are going to lean on. But if that is
14 part of your nomenclature --

15 MR. O'BRIEN: It's part of the support system that
16 supports the component in case of a pipe rupture.

17 MR. MICHELSON: On your definition of primary system
18 piping, did anyone suggest the same rules and so forth go
19 beyond the large diameter main loop piping, which is the
20 reason we asked for the definition?

21 MR. SHEWMON: That is the other part of the agenda.

22 MR. MICHELSON: Okay.

23 MR. SIESS: John, do you mean these multi-term
24 capacity snubbers that I have seen at the bottom of steam
25 generators are therefore pipewhip restraints?

1 MR. O'BRIEN: No. A pipewhip restraint is a device
2 placed near the pipe that only acts when the pipe breaks. If
3 the pipe breaks, that thing is --

4 MR. SIESS: Those snubbers you are talking about on
5 heavy equipment support, are those there for pipe whip or for
6 seismic?

7 MR. O'BRIEN: If you put them there for pipe break,
8 they are also there for seismic. You can't avoid it.

9 MR. SIESS: Do you have to have it for seismic?

10 MR. O'BRIEN: No. Most plants can get rid of them.
11 If you eliminate the pipe rupture, you can eliminate the
12 snubbers. If the pipewhip restraint acts during an
13 earthquake, it is an accident that you didn't anticipate. As
14 a matter of fact, that's one of the reasons we want to get rid
15 of them, is that they could act during an earthquake and give
16 you impact loads that you did not anticipate.

17 Anyway, somebody pointed out that we used the words
18 "extremely low" but we didn't define it. In addition, people
19 said the use of pipewhip restraints is unnecessary --

20 MR. SHEWMON: Would you move up what you are
21 talking about so we can read it?

22 MR. O'BRIEN: Sorry. People have noted that we said
23 the amendment was an unresolved safety issue and pointed out
24 to us that may not be. We also said you shall not have
25 augmented leak detection. They pointed out that also may

1 not be necessary.

2 These are some of the key issues that we have
3 received, and some of the public response to the proposed
4 rule.f

5 MR. OKRENT: It's a segment of the public, I would
6 say.

7 MR. O'BRIEN: Everybody was invited; nobody came.

8 [Slide.]

9 Regarding foreign practices, this information comes
10 primarily from surveys that we have undertaken with respect to
11 our Piping Review Committee, and the first four countries on
12 this slide have more or less adopted U.S. practices.
13 Particularly France and Japan are very close to what we have
14 been doing. Canada and Sweden have some divergence; however,
15 they are very close. They all have pipewhip restraints, they
16 all have double-ended guillotine breaks. I understand Canada
17 is now trying or anticipating something to do with a leak-
18 before-break technology.

19 MR. OKRENT: Let's look at France there a minute.
20 What are you saying is the practice in France?

21 MR. O'BRIEN: Very close to the United States.

22 MR. OKRENT: You mean the current practice. As far
23 as I know, they don't plan to change.

24 MR. O'BRIEN: It is hard when you have got a
25 standardized design to change.f

1 MR. OKRENT: I spoke to one of the Frenchmen
2 responsible in the area, and he didn't see a basis in his
3 opinion for removing the possibility of a break.

4 MR. O'BRIEN: It is hard for them with a
5 standardized design. They are not motivated. That's one of
6 the down sides of standardized designs. The British are
7 leaning towards present U.S. practices. They come and talk to
8 us frequently. They are going to put apparently some pipewhip
9 restraints in.

10 [Slide.]

11 The interesting cases, however, interesting to us,
12 are the Germans. Since 1984 the Germans have continued to
13 postulate a double-ended circumferential break in the primary
14 system for ECCS containment and equipment, environmental
15 qualification of equipment, but they no longer have a
16 double-ended guillotine break in the main coolant loop and to
17 the surge line and the RHR line either, part of the main
18 coolant or attached to branch lines or the main steam or main
19 feedwater lines. That is only that portion of the main steam
20 or main feed inside the containment from the steam generator
21 to the outside isolation valve, and they also only exclude
22 reaction forces and jet forces.

23 Somebody asked earlier, what are we going to replace
24 this, what kind of break? The answer is zero, nothing. In
25 our rule we say the pipe doesn't break. There are no reaction

1 forces at all. The Germans have a 10 percent flow rate.

2 MR. OKRENT: Before you leave the Germans, is that
3 something that they are backfitting to old plants or is it
4 something they are applying to plants built after a certain
5 time?

6 MR. O'BRIEN: Two plants I know are affected, but I
7 don't believe they are backfitting, no.

8 MR. OKRENT: Do they have any special quality
9 control on the primary system that goes beyond what the NRC
10 has?

11 MR. O'BRIEN: They have forged fittings, for one
12 thing.

13 MR. OKRENT: I think you should have that in the
14 picture. One should not have to ask about that to find it
15 out.

16 MR. O'BRIEN: I'm sorry. There are a number of
17 things they do. They have to remove snubbers off all their
18 components and replace them with bumpers. They have double
19 hull piping here and there. They have forged fittings, and
20 then the Italians recently switched to the German practice,
21 abandoning ours. We don't know what is happening beyond
22 the Soviet Bloc.

23 That is my presentation.

24 MR. EBERSOLE: Do any of these designs incorporate
25 bendable structural members in both directions which clear the

1 pipe but would act as seismic restraints in both directions?

2 MR. O'BRIEN: Are you talking about what we call
3 passive pipe restraints?

4 MR. EBERSOLE: I'm talking about pipe restraints in
5 the form of bendable supports which would act in the capacity
6 of current hydraulic or friction snubbers.

7 MR. O'BRIEN: You mean flexible bendable?

8 MR. EBERSOLE: Not flexible. Take a permanent set.
9 I'm trying to get the damping in. Bending ductile pipe
10 supports.

11 MR. GIESS: Like some of the stuff we saw in the
12 pictures from Chile. They were not intended to be that. I
13 think he is talking about the stuff at EPRI Spence Bush was
14 looking at.

15 MR. O'BRIEN: That's what we call passive pipe
16 restraints. We don't have any of those, to my knowledge.

17 MR. EBERSOLE: It would appear they would get rid of
18 some of these nasty problems with snubbers.

19 MR. SHEWMON: One utility you had was doing some
20 tests on collapsing a short segment of pipes. Just cut out a
21 piece and that would absorb it. I don't know whether it was
22 Duke, but that was a pipe --

23 MR. OKRENT: A different area.

24 Did you ask why the British, since they are starting
25 afresh, are not accepting the leak-before-break to the primary

1 system?

2 MR. O'BRIEN: No.

3 MR. OKRENT: It would have been relevant, I think.

4 MR. O'BRIEN: I talk to them a lot. They are just
5 adopting our practices.

6 MR. OKRENT: No. In fact, they thought about it in
7 depth and they have some very specific areas in the primary
8 system where they are reluctant to assume leak-before-break.
9 I think it would have been well to explore it.

10 MR. O'BRIEN: We did. We talked to them. Actually,
11 I talked to them and tried to persuade them not to do what
12 they are doing, but they are doing it anyway.

13 MR. SHEWMON: Why are they doing what they are
14 doing?

15 MR. O'BRIEN: I don't know. It beats me.

16 MR. REED: I am trying to remember from my Germany
17 visit. Didn't I hear at the meeting that leak before break
18 was not being adopted for political reasons to some extent in
19 Germany, and perhaps this could be the case with respect to
20 England. I'm not sure.

21 MR. OKRENT: I'm sorry. I think the Germans, in
22 fact, as he said, are for new plants in which they are putting
23 really --

24 MR. O'BRIEN: Better quality construction.

25 MR. OKRENT: Very significantly modified

1 requirements on the primary system construction. They are
2 proposing just what we showed. The British are concerned in
3 at least two areas of the primary system about ability to
4 inspect. One is when you are next to a pump.

5 MR. O'BRIEN: At the nozzle.

6 MR. OKRENT: Yes, and there is at least one
7 direction at the pressure vessel where they are concerned
8 about ability to inspect, and it is technical reasons like
9 this that are behind their unwillingness now to buy what you
10 are proposing for all BWRs without knowing the quality -- in
11 my opinion without knowing the quality of the primary system.

12 MR. SHEWMON: The premise of the leak before break,
13 though, is even if you cannot inspect it, it will leak before
14 break and you will have that to tell you when you have got a
15 large crack or when you have got a crack.

16 MR. OKRENT: It depends on certain assumptions about
17 the material properties in the weld.

18 MR. SHEWMON: Yes, of welds that we have samples of
19 or can test.

20 MR. OKRENT: We don't necessarily have samples or
21 can test samples for all plants.

22 MR. SHEWMON: I beg your pardon. We know what weld
23 metal it was made out of, we know what flux it was made out
24 of. It may not have been made the same day. In that regard,
25 we have properties on the material and have a pretty good idea

1 what it is.

2 MR. OKRENT: I would suggest that there has been
3 enough of a history of breakdown in quality control -- I don't
4 mean quality assurance -- over the years. You know, there is
5 some reason to assume that not all primary system welds have
6 the right weld metal.

7 MR. SHEWMON: I don't know what you mean by right.
8 I don't know of any evidence that we have of primary -- of
9 toughness problems in primary welds in pipes. These are
10 things that are out of radiations, so it's not a matter of
11 whether you have two-tenths copper or three-tenths copper, and
12 the tests that they have done and the people have gone back to
13 make the case that the bases for this has been to test these
14 things, and the results are that it is a conservative and
15 sound approach as far as any evidence I know of.

16 MR. OKRENT: I think the assumption is that it was
17 fabricated as designed, that's all, in all the analysis.

18 MR. SHEWMON: The assumption is that it's fabricated
19 out of sound-type material.

20 MR. SIESS: There is no assumption that it's
21 perfect, is there?

22 MR. SHEWMON: Few things are in this world.

23 MR. SIESS: In the calculations they do assume
24 flaws.

25 MR. SHEWMON: They assume flaws that are bigger than

1 anything anybody has ever found. They get big enough to
2 leak. The only assumption then is that they don't run beyond
3 that in a brittle fashion the way this damn guillotine break
4 assumption was that we have been saddled with for 40 years or
5 30 or whatever it is.

6 Okay. Are you back next, Bob?

7 MR. BOSNAK: Before I get into the arbitrary
8 intermediate breaks, let's just look again at what we're
9 talking about.

10 [Slide.]

11 That happens to be a Westinghouse loop. The
12 material that you see in yellow is the primary piping that
13 we're talking about. And here are the eleven breaks.
14 Actually three are branch line breaks that we are talking
15 about.

16 [Slide.]

17 And these are the break locations that we are saying
18 that for these plants we no longer have to worry about it,
19 either pipe width or jet impingement. Again, the branch lines
20 stay there. The breaks that are associated with the branch
21 lines, and those are terminal end breaks, and they're fairly
22 large. They are larger than the German 10 percent.

23 So again, this is exactly what we're talking about
24 with respect to PWR primary loops. And again, for those
25 plants that have these restraints in there, once the rule is

1 in place, if they have to remove the restraint to do
2 in-service examination, and most of them will have to do these
3 kinds of things, they will then, when the rule is in place, be
4 able to leave the structure out, not have to replace it. And
5 so it has tremendous benefits with respect to ALARA.

6 Now heat loss from the pipe, because of these pipe
7 width restraints, is quite large, and it adds to the
8 environment. There's just so many reasons -- of course, cost
9 is one that is a positive reason not to have to install these
10 if you're building a new plant.

11 Before we get into these two specific applications
12 -- one is Beaver Island; the other is Crystal River --

13 MR. SHEWMON: You are finished with the limited rule
14 now?

15 MR. BOSNAK: The limited rule --

16 MR. SHEWMON: That's what you're going with at this
17 time?

18 MR. BOSNAK: The limited rule, I think John said
19 19. We have to evaluate all the comments and then prepare a
20 final rule for the Commission. Roughly, it seems like by the
21 end of the year the final rule would go out and become
22 effective within either 30 or 60 days after.

23 MR. SHEWMON: Now you're going to change over to
24 these other things, which would not be part of that, which
25 would go beyond it, for our reaction, is that what you're

1 starting in on now or not?

2 MR. BOSNAK: Not at this time.

3 MR. SHEWMON: I would like to have you make a --

4 MR. BOSNAK: I will let you know. Actually we don't
5 plan to get into the broad scope rule, unless you have
6 questions.

7 MR. SHEWMON: Okay, fine. Go ahead.

8 MR. BOSNAK: Because the broad scope rule still has
9 not been published. We don't even know the final form that
10 it's going to take.

11 [Slide.]

12 The next area is arbitrary intermediate breaks. I
13 have listed here for you the plants that are involved. And
14 let me define what an arbitrary intermediate break is.

15 First of all, in accordance with our current rule,
16 the Standard Review Plan, 361, 362, you must postulate pipe
17 breaks in a system at a terminal end, any terminal end, and at
18 those locations in which you exceed certain special criteria,
19 or in the case of Class I systems, certain fatigue criteria.
20 The only systems in which fatigue is evaluated are Class I.
21 That's why the fatigue criteria does not apply for Class II
22 and Class III.

23 Now these values, these specified limits, are in
24 general 80 percent of the normal limits specified in the
25 code. So if you are above that break point, you have to

1 postulate a break, and if you don't do a good design on your
2 system, obviously you're going to have more.

3 We have well-designed systems in which there are no
4 locations other than the terminal ends, and those are not
5 considered at all. They stay. But there are no intermediate
6 locations that exceed our 80 percent criteria.

7 MR. MICHELSON: Are anchor points considered
8 terminal ends?

9 MR. BOSNAX: Anchor points are terminal ends.
10 So what do you do if you don't have any?

11 The rule says arbitrarily select two, and these are
12 the so-called arbitrary intermediate breaks.

13 Now we started this in late '84 at Catawba,
14 Catawba-2. Unit 2 was the first plant. Basically, I think we
15 had an Owners Group, but Duke Power was interested in going
16 ahead and proceeding ahead of the rest of the plants, and
17 there was interaction with the Staff, about six to eight
18 months, I believe, where we went through and decided which
19 systems, if any, are subject to large dynamic load fatigue for
20 stress corrosion cracking.

21 Once we ruled those out, then we went ahead and
22 said, for the other systems that these three diseases, if
23 you will, are not present, you may go ahead and eliminate the
24 arbitrary intermediate breaks. This was not an exemption
25 based on fracture mechanics. It was just a deviation, if you

1 will, based on the Standard Review Plan.

2 Now what kind of tradeoff did we get? We do have
3 the caveat that any piece of equipment that is there
4 throughout the piping run -- and this is a system that we're
5 talking about from terminal end or anchor to anchor -- all of
6 the equipment has to be qualified for non-dynamic effects of a
7 non-mechanistic break with the greatest consequences on the
8 equipment.

9 Now we think what we have there is much better with
10 respect to plant safety than what we had before, applying
11 arbitrarily, if you will, the fact that pipes are going to
12 break at these two locations. And they were, as I tried to
13 explain, selected rather arbitrarily.

14 MR. SHEWMON: Would you explain what that last
15 statement means? Be qualified for non-dynamic effects of a
16 non-mechanistic pipe break with the greatest consequences?

17 MR. BOSNAK In other words, you don't have to
18 qualify equipment for a jet focusing on it, but you do have to
19 qualify the equipment for static conditions of pressure,
20 temperature, flooding. That's what that means.

21 MR. MICHELSON: Resulting from what kind of break?
22 Is it still the double-ended rupture?

23 MR. BOSNAK: Whatever you want. Where there are no
24 dynamic effects associated with it.

25 MR. MICHELSON: It's not whatever you want; it's

1 whatever is required, because it makes quite a difference in
2 pressure and temperature as to what you assume. So what do
3 you require to be assumed?

4 MR. BOSNAK: Static conditions of the pressure and
5 temperature of the fluid.

6 MR. MICHELSON: I understand that. But you have to
7 have some kind of break in order to get time into this whole
8 thing.

9 MR. BOSNAK: We're not getting time in. We're
10 staying away from that.

11 MR. MICHELSON: If you've got vent areas, whatever,
12 you've got to put some time limit on this.

13 MR. SHEWMON: How high does the water level get
14 before it stops coming?

15 MR. BOSNAK: They can look at it. If they do have
16 vent areas, if they do have means for the fluid that escapes,
17 you may take that into account. But again, we are not getting
18 into situations in which we have, in one millisecond, a sudden
19 release of the fuel in the pipe.

20 MR. MICHELSON: You understand, of course, some of
21 these transient pressures, which are sufficiently high to
22 cause walls to cave in and whatever, are created in a short
23 time range.

24 Are you essentially saying you are eliminating
25 those?

1 MR. SHEWMON: Yes.

2 MR. BOSNAK: Yes.

3 MR. SHEWMON: But what the greatest consequences on
4 equipment are, I don't know yet. Let me stay with that one.

5 MR. BOSNAK: You have to look at the location. If
6 you have a particular item, that's what we're getting at with
7 the greatest consequences. In other words, if you have a
8 system that goes from here to here (indicating) and an item
9 over here (indicating), you cannot select your break, if you
10 will, here (indicating). It has got to have the greatest
11 static --

12 MR. SHEWMON: In other words, you've very little
13 room, not much imagination. Give me an example.

14 MR. BOSNAK: That was the example I tried to give
15 you.

16 MR. SHEWMON: What's the item?

17 MR. BOSNAK: My item, my motor control center, for
18 instance, is here (indicating). I have a break over there
19 (indicating), and that can't affect it. We are saying you
20 have to look at that location, so that it has the greatest
21 consequences.

22 MR. SHEWMON: You don't have to consider inertial
23 effects, but you have to consider an awful lot of water, is
24 that what you mean by standard?

25 MR. BOSNAK: That's correct. Flooding. If you do

1 have an egress for the water, you can take that into account.
2 But if you don't have that sort of situation, it might flood
3 the motor control center.

4 MR. MICHELSON: That doesn't help me a lot, though.
5 I've got a small, given room. It's got a large pipe in it.
6 Depending on how that pipe breaks --

7 MR. SHEWMON: Are there any small, given rooms in
8 that system shown there?

9 MR. MICHELSON: Inside of containment, there's a lot
10 of compartments.

11 MR. SHEWMON: He only showed the primary system
12 between the steam generator --

13 MR. BOSNAK: This applies to all high-energy lines.
14 We're not talking about -- it's not the primary loop anymore.
15 That's why I tried to divorce this from the rest of the -- it
16 has nothing to do with the basic rule.

17 MR. MICHELSON: Inside and outside of containment,
18 as I understand it.

19 MR. BOSNAK: That's correct.

20 MR. MICHELSON: Back to my question, though.
21 Depending upon the rate at which the energy is released from
22 that pipe determines what the pressure is in the room and so
23 forth. So you said, okay, I'm not going to take shock wave
24 effects of millisecond type breaks.

25 What break am I going to take in determining the

1 pressure in the room?

2 MR. BOSNAK: That is why we tried to get into the
3 non-mechanistic situation.

4 MR. MICHELSON: Okay, that's a good word, I guess.
5 I don't understand what it means, and that's what I'm trying
6 to find out. What is that non-mechanistic break?

7 MR. BOSNAK: It means you don't have to go through a
8 time-history type of analysis.

9 MR. MICHELSON: What do you go through?

10 MR. BOSNAK: Again, you consider, without any
11 dynamic effects, that you're going to have an opening in that
12 fluid pipe, and it is going to spray, if you will, just
13 distribute the fluid, and its pressure, its temperature, its
14 humidity, moisture.

15 MR. MICHELSON: But that temperature is a dynamic
16 effect, because it depends upon the rate of the materials
17 entering the volume and the rate at which it's filling the
18 volume.

19 MR. BOSNAK: Take the temperature and pressure
20 within the fluid line. That's what you use.

21 MR. MICHELSON: That doesn't count at all. Even
22 simple thermodynamics tells you that's not right. Long ago at
23 TMI, we learned you don't take the condition inside the pipe
24 and think that that's what's in the room.

25 MR. SHEWMON: That's an upper bound.

1 MR. BOSNAK: That's an upper bound, and that's what
2 we're saying to use.

3 MR. MICHELSON: No superheating, for instance, at
4 all.

5 MR. BOSNAK: No superheating.

6 MR. MICHELSON: Use the temperature of the fluid in
7 the pipe that breaks.

8 Now how do you calculate the pressure? I don't want
9 to get into details.

10 MR. BOSNAK: Take the pressure that's in the basic
11 line.

12 MR. MICHELSON: That's the pressure in the room?

13 MR. BOSNAK: That's what you use an upper bound.

14 MR. MICHELSON: I hope not. Rooms can't take a
15 thousand pounds pressure.

16 MR. BOSNAK: Again, we're not looking at the
17 structure. We're looking at equipment, equipment
18 qualification.

19 MR. MICHELSON: Are you any longer considering the
20 effects on structures of pipe breaks, other than jet
21 impingement and whipping? Are you eliminating pressurization
22 compartments as a potential problem?

23 MR. BOSNAK: As far as pressurization compartments
24 are concerned for these situations, no. Again, the answer is,
25 you look at the pressure and temperature, and you come up with

1 a scenario that demonstrates that what you have will not --

2 MR. MICHELSON: This sounds extremely strange to
3 me. Maybe everybody else understands it; I don't understand
4 it.

5 MR. MARK: Do you assume that you have an orifice
6 equal in size to the diameter of the pipe with fluid in that
7 pipe with a temperature and pressure that you know to be
8 there, and that stuff comes out at that rate into the room?

9 MR. MICHELSON: That's a good problem. That's the
10 one we have been using.

11 MR. BOSNAK: Again, these are areas in which there
12 were formerly isolated breaks.

13 MR. SHEWMON: What you want to know is whether or
14 not a piece of presumed electrical or mechanical equipment in
15 this space will continue to function. You assume that there
16 is not a jet, and thus inertial forces don't come on it, but
17 with regard to temperature or water levels that could come or
18 steam, you do make sure that the equipment can withstand it.

19 MR. BOSNAK: You do have to have there a
20 deterministic model based on what you have on that particular
21 space with respect to egress of fluid as it comes out of the
22 pipe, so that you would, in effect, have an orifice.

23 MR. MICHELSON: You must postulate a break size of
24 some sort for the purposes of calculating environmental
25 conditions. I don't know how you would ever do it otherwise.

1 But you said, at first, you didn't do that, and now
2 I think you're coming --

3 MR. SHEWMON: He said it doesn't have inertial
4 effects.

5 MR. MICHELSON: That I don't have any sweat with.

6 MR. SHEWMON: Inertial effects are the only thing
7 you've eliminated.

8 MR. BOSNAK: We start with an upper bound
9 situation. If somebody can live with the pressure and
10 temperature of the fluid in the line, fine. That makes it
11 quite simple. If they cannot, then we're into a situation in
12 which you assess what you have.

13 Most all of these plants have had breaks in these
14 particular compartments anyway, so that from the point of view
15 of equipment qualification, this is what they are using
16 throughout the run of the system.

17 MR. MICHELSON: I think you are beginning now to
18 back off from requiring the users' old original analysis. You
19 can come up with some new justification for lesser
20 qualifications.

21 MR. BOSNAK: We're saying, in spaces in which you've
22 never had a break before, you could arbitrarily say, "Okay. I
23 don't have to qualify my equipment for anything." We are now
24 saying that you do have to have qualification, and it must be
25 along these lines.

1 MR. EBERSOLE: Would this apply to a 400-pound cold
2 water pipe?

3 MR. BOSNAK: If it was a system in which we didn't
4 have to worry about waterhammer, yes.

5 MR. EBERSOLE: If it was a system that you did have
6 to worry about waterhammer, yes, also?

7 MR. BOSNAK: If it was a system that you did have to
8 worry about waterhammer, this would not apply.

9 MR. SHEWMON: Dave, I'm not sure what subcommittee
10 should consider this, but I think at this point we're into
11 things which are not a report on something which has been gone
12 over in the subcommittee, and we have gone through our time.

13 I think we got the main point across, which was a
14 GDC-4 modification.

15 MR. BOSNAK: This has nothing to do with GDC-4, and
16 that's the main thing you want to keep in mind. It has
17 nothing to do with GDC-4.

18 You asked for us to tell you where we were getting
19 into changing how postulated pipe breaks were considered.
20 This is another category completely separate from GDC-4.

21 MR. SHEWMON: Nobody's equipment qualification, is
22 that right, conditions under which you must qualify equipment;
23 is that the question that arises here?

24 MR. BOSNAK: That seems to be one of the questions
25 that's being asked.

1 MR. MICHELSON: Another question is the operability,
2 say, of valves under dynamic conditions. This eliminates the
3 dynamic conditions that the valve ever sees. We've got to
4 think about, do we want to eliminate dynamic requirements on
5 valves? If we do, fine. But we really have to give it, you
6 know, some careful thought.

7 MR. BOSNAK: Which dynamic conditions are you
8 referring to?

9 MR. MICHELSON: If you break a pipe downstream of
10 the valve that's to isolate the break, do we still include
11 that kind of a break in the qualification of a valve?

12 MR. BOSNAK: You still have somewhere in that system
13 a break. It's a terminal end break.

14 MR. MICHELSON: But you really are fuzzy on it. You
15 said we will have a break for the purposes of determining
16 environment. You haven't said we'll have a break for the
17 purposes of determining dynamic operating conditions in the
18 qualifications of that equipment.

19 MR. BOSNAK: If that break is one of those that it
20 has eliminated, you don't have it any longer.

21 MR. MICHELSON: That's right. And I think you're
22 eliminating those breaks.

23 MR. EBERSOLE: A clarification, please, on the first
24 two bullets. It's ambiguous. Breaks postulated at terminal
25 end and at intermediate locations, and there you qualify it

1 with stress or usage factors --

2 MR. BOSNAK: That's today's requirement. That
3 should not be ambiguous. That's what's on the books today.

4 MR. EBERSOLE: So that's where you have a fatigue
5 factor in both locations, the ends or in the middle.

6 MR. BOSNAK: Forget the ends. The ends are not
7 changing at all. Usually you will have a fatigue factor
8 there. Usually that's where the fatigue factor is higher. So
9 we're not changing that at all.

10 MR. EBERSOLE: So you still get the ends.

11 MR. BOSNAK: You always get the terminal ends,
12 anchors.

13 MR. EBERSOLE: They'll get a full-size break, and
14 you have to deal with thermodynamics.

15 MR. BOSNAK: Exactly. That doesn't change.

16 MR. EBERSOLE: That means, for instance, main
17 feedwater will have to be considered to break upstream of the
18 swing checks, and you must deal with the hypothetical break
19 like that and have the ilapper valves be defended against
20 impact loads on reverse flow of the boiler pipe.

21 MR. BOSNAK: That's correct. That's not going to
22 change.

23 MR. EBERSOLE: By the way, that hasn't been very
24 well done.

25 MR. BOSNAK: I know. I agree.

1 If we do have the time, I would like to get into
2 these two other plants, because we would like to get the
3 committee's input on Crystal River and also Beaver Valley, if
4 that's possible.

5 MR. MICHELSON: Clarify where on your chart did you
6 tell us that we still have the terminal end breaks, because
7 that statement we were dealing with didn't seem to say that.

8 MR. BOSNAK: It says "postulated at terminal ends
9 and at intermediate locations." I'm saying here, in
10 well-designed systems, there are no intermediate, but there
11 are always terminal ends.

12 MR. MICHELSON: I read this statement, the third
13 from the bottom, it says "all equipment throughout piping run
14 is qualified." I read that as meaning that throughout piping
15 run, there are none --

16 MR. BOSNAK: If you have a break and if you're in a
17 terminal end location, that is still there. We haven't
18 changed that. We haven't changed any of the effects.

19 MR. WARD: Bob, let me interrupt a minute. I think
20 the committee -- there is enough concern about this that we
21 are going to want to hear more about it. I think you have to
22 get clarified enough on what the issues of concern are to
23 figure out which subcommittee should take a look at it, but I
24 think we are going to want to hear more.

25 Why don't you go on? Were you going to talk about

1 the Crystal River and Beaver Valley?

2 MR. BOSNAK: I would like to.

3 MR. WARD: Why don't you move on to that. Just
4 recognize that we probably haven't closed out with you on the
5 intermediate break issue.

6 [Slide.]

7 MR. BOSNAK: I want to make it clear here, these are
8 preliminary proposals that we have.

9 Now with respect to Crystal River, they have now
10 installed 32, and they are between 1000 and 2000 kip snubbers
11 on the reactor coolant pump. They have had B&W look at a --
12 call it, if you will, an optimization study, an analytical
13 study to see what they could do.

14 These large snubbers cannot be tested. They are
15 rather unreliable with respect to their construction, the
16 ability to come in periodically and do the kind of testing
17 that snubbers require. So what they are proposing is to
18 rearrange the system, if you will -- and this is a question
19 that Dr. Siess raised earlier -- since the LOCA loads are, in
20 effect, going away, what would you all think about putting in
21 eight smaller snubbers? Again, they're talking about 400 kip,
22 much smaller than the two million pound snubbers, and
23 tentatively four rigid restraints.

24 Again, the benefits are as you see them here. The
25 margins obviously are going to be revised.

1 In your letter of June of '83, you mentioned the
2 fact that we want to be sure that we have reliability of the
3 primary loop, the supports for the primary loop. The margins
4 will not be what they are today. In some cases, they are
5 going to increase, but in most cases, they are probably
6 somewhat less.

7 Now we believe this will make a more reliable
8 system. Again, we have only had a tentative look-see, but
9 from what we have seen so far, we believe that it represents a
10 benefit, a positive way to go with respect to the primary loop
11 on this particular plant.

12 Now once we do this for one plant, obviously others
13 will probably be interested in doing it, because in the
14 primary loop, again because of these tremendously large pipe
15 break loads, we do have extremely large snubbers. So this
16 represents, I would call it forward thinking.

17 We would like to have the benefit of the committee's
18 thoughts with respect to a proposal such as this.

19 MR. OKRENT: What is the inspectability of the welds
20 joining piping to the pump? Is it good from both sides?

21 MR. BOSNAK: For this particular plant, I can't
22 answer that question. It's one of the things we want to be
23 looking at.

24 MR. OKRENT: Do you want to get an opinion today
25 from the committee? I don't understand what --

1 MR. BOSNAK: We want to know how you feel about
2 trying to go back in, given the fact that we have leak before
3 break, and the large dynamic loads for the primary loop are no
4 longer present. Should we -- or is there any objection to
5 going in and looking at this to see if we can improve the
6 system reliability?

7 MR. REED: This is a removal operation of the 32, or
8 are they not installed?

9 MR. BOSNAK: These are all there. Currently there
10 are -- and I have somewhere in here in their submission the
11 exact size -- but there are 323 snubbers, and they are between
12 1000 and 2000 kips. They are large snubbers. They are only
13 there for the reactor coolant pump.

14 MR. REED: I can certainly see many improvements
15 from their removal.

16 MR. OKRENT: I would suggest that as part of your
17 review, if you review this, that you make an effort to find
18 out why the British are not buying leak before break and
19 whether -- and I don't know; I don't recall --

20 MR. BOSNAK: The last encounter, I think, we had
21 with the British was that they were still considering it.
22 They have gone ahead with decoupling of LOCA and SSE, but
23 they are still considering it, and it may be a political
24 situation, as mentioned here earlier.

25 MR. WARD: You know, the whole comparison of our

1 practice and foreign practice, I guess bothered me a little
2 bit. Perhaps you are moving out into a leadership role and
3 made changes, which is fine. But on the other hand, the
4 British, despite maybe their LWR program is rather abstract, I
5 didn't think O'Brian gave us a very satisfactory answer when
6 Okrent asked him what the British thinking was.

7 If they do have some thought-out --

8 MR. BOSNAK: We will attempt to get, as best we can,
9 the latest, up-to-date input from them.

10 MR. OKRENT: You might try talking to Mr. Curry.

11 MR. WARD: The Germans have gone a long way in this
12 direction, but they are making some rather substantial changes
13 in the piping quality. Or are they really substantial? Are
14 they just apparent?

15 MR. SHEWMON: They are changing stresses.

16 MR. BOSNAK: They are changing their techniques.
17 They are trying to use forged components. They are
18 eliminating, wherever they can, weldments. I think all of the
19 new plants around the world are trying to do that.

20 MR. SHEWMON: I suggest we close at this point.

21 MR. BOSNAK: If I can get into Beaver Valley, just
22 to give you a quick idea of where they stand.

23 MR. SHEWMON: You aren't going to get a decision
24 here.

25 MR. BOSNAK: We're not looking for that. I

1 understand they are going to come in in September, later this
2 month, to talk to the subcommittee. But they are looking at
3 the balance-of-plant systems and trying to see in which
4 systems can they say they're going to have leak before break
5 performance and in which systems can they again remove these
6 dynamic restraints, pipe whip restraints, jet impingement
7 barriers. That is what they are proposing.

8 It is an innovative approach. They want to study
9 all of the systems for stress corrosion fatigue and large
10 dynamic loads.

11 Our legal friends tell us that they believe they
12 would need the broad scope rule in place before they could get
13 ahead with this thing, but that is just a legal opinion.

14 [Whereupon, at 5:45 o'clock, p.m., the transcribed
15 portion of the meeting was concluded.]

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CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceedings
before the United States Nuclear Regulatory Commission in the
matter of: ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

Name of Proceeding: 305th General Meeting

Docket No.:

Place: Washington, D. C.

Date: Thursday, September 12, 1985

were held as herein appears and that this is the original
transcript thereof for the file of the United States Nuclear
Regulatory Commission.

(Signature)

(Typed Name of Reporter) Mimie Meltzer

Ann Riley & Associates, Ltd.

305TH ACRS MEETING
SEPTEMBER 12, 1985

GESSAR II

10:45 AM to 3:15 PM [includes Lunch Break, tentatively set at 12:30 to 1:30 PM]

	<u>Presenter</u>	<u>Time in Min.</u>
1. Definition of FDA	NRC	20
2. Major Results and Conclusions from PRA; Qualifications concerning PRA Staff Estimates of Mean core melt frequency	NRC	30
	GE	10
3. Existing Quantitative Interface Requirements on Performance, Reliability, etc. including seismic	NRC	15
	GE	10
4. Safety Goals for Future Plants Containment Requirements for future plants	NRC	10-15
5. Containment failure likelihood and mode, given core melt thru vessel	NRC	10
6. Hydrogen control: Why not seismic requirements on ignitors?	NRC	10
7. USIs and GSIs		
A-43 - Why cyclone pump?	GE	5
Why rely on UPPS with no detailed analysis?	NRC	5
8. Problem in staff review of flooding PRA	NRC	10
9. Status of Containment Venting Design	GE	10
10. Status of UPPS? Seismic, other features Can it work if there is a large fire? Should it be a much better system? Bunkered?	GE	20-25
11. Review of adverse effects due to failures or spurious actuations caused by an earthquake;	NRC	10
Fires caused by an earthquake	Not analyzed by GE or NRC	10
12. Other		15

Agenda for ACRS
Meeting on September 12, 1985
8:45 a.m.
Room 1046, H Street

RECENT SIGNIFICANT EVENTS

<u>Date</u>	<u>Plant</u>	<u>Event</u>	<u>Presenter/Office telephone</u>	<u>Page</u>
9/4/85	Hope Creek	Inadvertent Actuation of Fire Suppression System	J. Henderson, IE 492-9654	2
7/21/85	Turkey Pt. 3	Post Trip Loss of Auxiliary Feedwater	J. Henderson, IE 492-9654	3
7/23/85	Turkey Pt.	Potential MSIV Failure At Low Steam Flow	V. Hodge, IE 492-7275	4
8/7/85 9/3/85	Maine Yankee	Common Mode Problems with Steam Generator Pressure Indication	J. T. Beard, NRR 492-7465	9
8/28/85	Peach Bottom	New Pipe Crack Indications	G. Gears, NRR 492-8362	13
7/2/85	*Fermi 2	Premature Criticality	N. Chrissotimos RIII 312-790-5716	15

*no formal presentation

HOPE CREEK CO₂ RELEASE

9/4/85

J. B. HENDERSON, IE-EGCB

- RELEASE OCCURRED ABOUT 8:45 AM
- A SITE EMERGENCY RESPONSE DRILL WAS IN PROGRESS
- CO₂ RELEASED FROM STORAGE TANK TO PROTECTED VOLUME THROUGH NORMAL PIPING SYSTEM
- PROTECTED VOLUME, FUEL TANK ROOM UNDER DIESEL-GENERATOR
- CO₂ ESCAPED TO OTHER PARTS OF BUILDING COMPLEX
- PERSONNEL EVACUATED FROM BUILDING COMPLEX
- NO APPARENT DAMAGE TO STRUCTURES, SYSTEMS OR COMPONENTS
- COMPLICATION - MOST THOUGHT THIS PART OF SCENARIO, NOT REAL
- 23 PERSONNEL TRANSPORTED TO HOSPITAL
- INADVERTENT ACTUATION SIGNAL
- PROGRAMMED DISCHARGE 2 TONS
ACTUAL - 10 TONS
- LICENSEE BELIEVES PROBLEM MAY BE IN CONTROL PANEL
- PANEL SENT TO MFR (CARDOX) FOR EVALUATION

ACRS MEETING 9/12/85

TURKEY POINT 3 POST-TRIP LOSS OF AFW

JULY 21, 1985 (J. B. HENDERSON, IE)

- PROBLEM - ALL THREE TURBINE-DRIVEN AFW PUMPS BECAME INOPERABLE DURING POST-TRIP RECOVERY PERIOD.
- SAFETY SIGNIFICANCE - IMPAIRMENT OF DECAY HEAT REMOVAL CAPABILITY.
- BRIEFING SIGNIFICANCE - THE ONLY SITE OTHER THAN DAVIS-BESSE WITH NO ELECTRIC DRIVE AFW PUMPS.
- TWO TURBINES TRIPPED TO LOCK OUT ON MECHANICAL OVERSPEED TRIP. FLOW CONTROL VALVE ON THIRD UNIT FAILED.
- LICENSEE CORRECTIVE ACTION - 1. RETRAINING ON TURBINE GOVERNOR RESET. 2. PERFORM OVERDUE MAINTENANCE ON AIR SUPPLY SYSTEM TO CONTROL VALVE.
- OVERSPEED TRIP PROBLEM MAY BE GENERIC TO A SIZEABLE CLASS OF TURBINES
- NRC FOLLOWUP - NOT DEFINED YET

POTENTIAL MSIV FAILURE
AT LOW STEAM FLOW

TURKEY PT. 3, 4

JULY 23, 1985

BY VERN HODGE, IE

TWO ISSUES:

1. UNANALYZED CONDITION FOR MSLB ACCIDENT
2. INADEQUATE TESTING PRACTICE

UNANALYZED CONDITION FOR MSLBA

1. MSIVs WON'T CLOSE
 - A. WITHOUT STEAM FLOW
 - B. WITHOUT INSTRUMENT AIR ACTUATOR POWER
 - C. ACCUMULATORS ARE TOO SMALL
2. PROBLEM APPLIES TO TURKEY POINT AND ROBINSON
3. THRESHOLD STEAM FLOW NOT KNOWN
ASSUMED TO EXCEED AFW CAPABILITY

CONTINUED BLOWDOWN POSSIBLE

JUSTIFICATION FOR CONTINUED OPERATION

ASSURE SUFFICIENT INSTRUMENT AIR:

1. DIESEL AIR COMPRESSOR BACKS UP PLANT SYSTEM
2. FOSSIL PLANT SYSTEMS TIED IN FOR BACKUP
3. PLANT SHUTDOWN ON FAILED INSTRUMENT AIR SUPPLY

CORRECTIVE ACTION

EXPEDITED DESIGN MODIFICATION TO:

1. ASSURE MSIV CLOSURE IN 5 SEC W/O STEAM ASSISTANCE
2. ALLOW TESTING MSIV CLOSURE W/ SECURED ELECTRIC AND INSTRUMENT AIR ACTUATOR POWER

INADEQUATE TESTING PRACTICE

MSIVs STROKE TESTED WITH INSTRUMENT AIR CONNECTED

TURKEY PT, ROBINSON CITED IN FEBRUARY 1985 TO VIOLATE
10 CFR 50.55A(G):

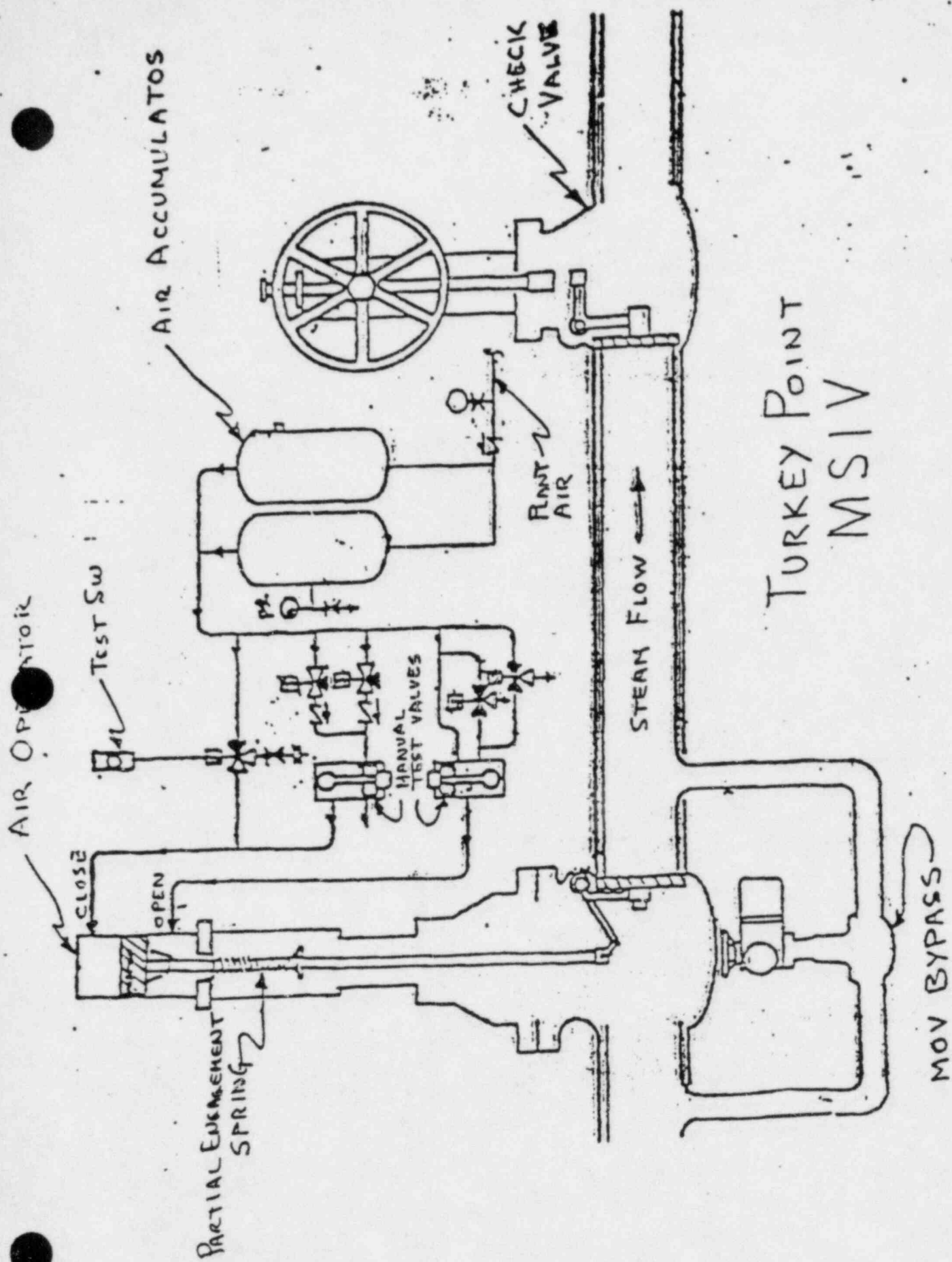
IST OF SAFETY RELATED PUMPS AND VALVES MUST COMPLY
WITH ASME BPV, SECTION XI

FAIL SAFE VALVES MUST BE TESTED BY LOSS OF ACTUATOR
POWER (PARA. IWV-3415)

ACTUATOR POWER INCLUDES BOTH ELECTRIC POWER AND
INSTRUMENT AIR POWER

NRC RESPONSE

AN INFORMATION NOTICE IS BEING PREPARED



MAINE YANKEE: TWO COMMON MODE PROBLEMS WITH STEAM
GENERATOR INSTRUMENTATION

(J. T. BEARD)

SUMMARY

- AUG. 7, 1985: PLANT AT 78% POWER (EOC), FOUND ROOT VALVES "NOT FULLY OPEN" FOR 9 OF 12 PRESSURE TRANSMITTERS.
- SEPT. 3, 1985: REFUELING OUTAGE TESTING REVEALED THE "A" PRESSURE CHANNEL FOR EACH STEAM GENERATOR WOULD NOT TRIP--- DESIGN MODIFICATION ERROR---GROUNDING.
- SIGNIFICANCE: PRESSURE INSTRUMENTATION WOULD NOT HAVE RESPONDED PROPERLY TO STEAM LINE BREAK ACCIDENT; BOTH CONDITIONS EXISTED FOR WHOLE OPERATING CYCLE. DIVERSE INSTRUMENTATION (E.G., S/G LEVEL) WOULD HAVE ACTUATED, LATER.

ROOT VALVE PROBLEM

- "D" PRESSURE CHANNEL ON S/G #1 NOTICED TO BE "SAGGING"; FOUND 3 VALVES FULLY CLOSED (BUT LEAKING), 6 VALVES "PARTIALLY OPEN."
- VALVES WERE CLOSED FOR HYDRO-TEST; SPRING, 1984.

ROOT VALVE PROBLEM

INSTR. CHANNEL

STEAM
GENERATOR

	A	B	C	D
1		PARTIALLY CLOSED	<u>CLOSED</u>	<u>CLOSED</u>
2		PARTIALLY CLOSED	PARTIALLY CLOSED	<u>CLOSED</u>
3		PARTIALLY CLOSED	PARTIALLY CLOSED	PARTIALLY CLOSED

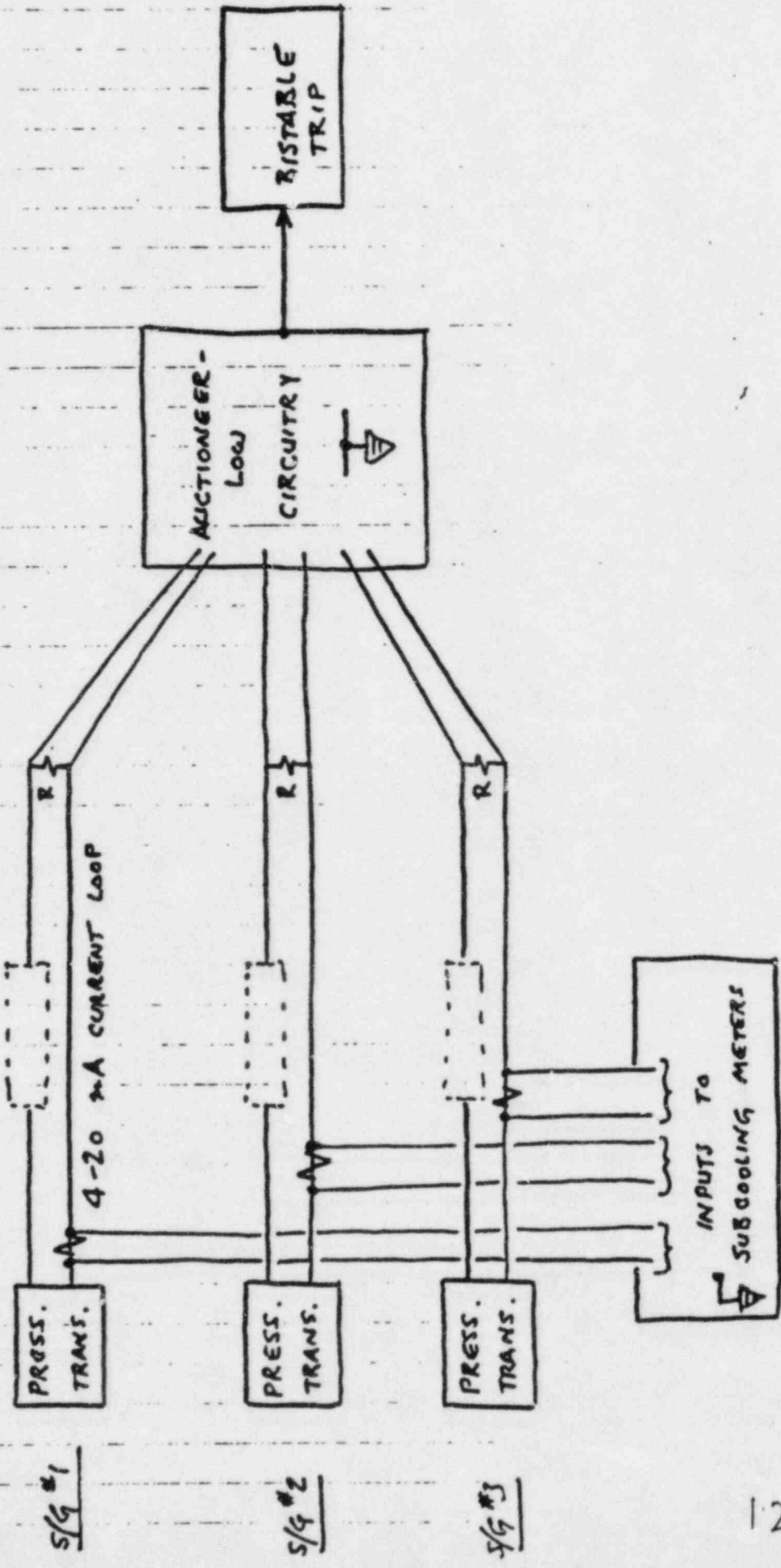
- INSTR. ROOT VALVES NOT ON ANY CHECKLIST. LICENSEE ASSUMPTION WAS: "IF INSTRUMENT INDICATES, VALVES MUST BE OKAY." LEAKAGE CAUSED SATISFACTION STEADY-STATE INDICATIONS. SLOW TRANSIENT RESPONSES (UP TO 60 SECONDS).

DESIGN PROBLEM

- EACH S/G PRESSURE CHANNEL "AUCTIONEERS-LOW" SIGNALS FROM TRANSMITTER LOOPS FROM ALL THREE S/G'S. MODIFICATION MADE TO TAP OFF ANOTHER SIGNAL FROM EACH LOOP TO PROVIDE INPUTS TO SUB-COOLING METERS.
- DEFICIENCY IN DESIGN OF MODIFICATION---ANOTHER SIGNAL COMMON ESTABLISHED WITHOUT CHECKING COMMON IN EXISTING CIRCUIT FOR RPS.
- DESIGN REVIEWS FAILED TO FIND ERROR; MOD. INSTALLED AFTER 18-MONTH SURVEILLANCE TEST; NO POST-MODIFICATION TESTING OF RPS. UNDETECTED FOR ENTIRE OPERATING CYCLE.

DESIGN PROBLEM

STEAM GENERATOR PRESSURE CHANNEL "A"



PEACH BOTTOM UNIT 3 - NEW PIPE CRACK INDICATIONS

AUGUST 19, 1985 (G, GEARS, NRR)

- PROBLEM - REINSPECTION OF UNIT 3 RECIRCULATION AND RHR LINES FOR IGSCC (GENERIC LETTER 84-11) REVEALED NEW INDICATIONS.
- NUMEROUS CRACKS INDICATED BY NEW GE "SMART" UT SYSTEM.
- MANY CRACKS DISCOVERED ON WELDS WHICH HAD NO INDICATIONS UNDER PREVIOUS INSPECTIONS (1983, IEB 83-02).
- ONE CRACK WAS CALLED AT 360°, 35-55% THRU-WALL.
- SIGNIFICANCE - HIGH PROBABILITY CRACKS WERE "MISSED" UNDER EARLIER INSPECTION PROGRAMS.
 - THESE FINDINGS CONFIRM RECENT TESTS RESULTS ON CUT-OUT WELDS (I.E., CRACKS HAVE BEEN "MISSED").
 - QUESTIONS NOW RAISED ON QUALITY OF REINSPECTIONS.
- BWROG BEING ASKED TO ADDRESS THESE ISSUES IN A SEPTEMBER 20, 1985 MEETING WITH NRR.

PEACH BOTTOM UNIT NO. 3
ULTRASONIC TECHNIQUE COMPARISON

GENERAL ELECTRIC

1
9
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3
PERSONNEL: No specific IGSCC detection or sizing training. Only procedure demonstration by representative personnel required by I.E. Bulletin 82-03.

EQUIPMENT: All examinations performed manually utilizing 1.5 MHZ transducers. No sophisticated sizing transducers available for indication discrimination or sizing.

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PERSONNEL: All Level II and III personnel are EPRI trained and certified in the detection of IGSCC. All Level I personnel are trained to the level of their involvement in exams. All personnel utilized for sizing of indications are EPRI trained and certified in planar flaw sizing.

14
EQUIPMENT: All exams are performed with 2.25 MHZ transducers. Where configurations permit, the exams were performed with the "SMART" automatic system. All questionable indications are scanned utilizing sizing transducers such as "SLIC-40", "WSY-70", OR "RTD" to aid in determining indication origin.

SOUTHWEST RESEARCH

PERSONNEL: No specific IGSCC detection or sizing training. Only procedure demonstration by representative personnel required by I.E. Bulletin 82-03.

EQUIPMENT: All examinations performed manually utilizing 1.5 MHZ transducers. No sophisticated sizing transducers available for indication discrimination or sizing.

PERSONNEL: All Level II and III personnel are EPRI trained and certified in the detection of IGSCC. All Level I personnel are trained to the level of their involvement in exams. All personnel utilized for sizing of indications are EPRI trained and certified in planar flaw sizing.

EQUIPMENT: All exams performed manually utilizing 1.5 MHZ transducers. All suspected indications are scanned utilizing the "SLIC-40" transducer for discrimination and subsequent sizing.

FERMI 2 PREMATURE CRITICALITY EVENT
JULY 2, 1985 (N. CHRISSOTIMOS, RIII)

- * Problem - Reactor brought critical prematurely
- * Safety Significance - Safety limits not violated procedure violation
- * Low power license issued 3/20/85
- * Initial Criticality on 6/21/85
- * Reactor being restarted in source range following a scram
- * Operator pulled eleven rods in group 3, one at a time, from notch 00 (full in) to notch 48 (full out). Pull sheet called for pulling group 3 rods from 00 to 04 as first increment.
- * Root cause was operator failure to follow procedure. Contributing causes were failure to:
 - Adequately manage control room
 - Training vs. procedures
 - Use hardware (RWM) to fullest potential
- * Subsequent NRC Actions
 - Informed of event on 7/15/85 (after full power license issued)
 - CAL issued by RIII on 7/16/85
- * Status of Resolution
 - DECo response to RIII CAL
 - Augmented inspections
 - Restricted to 5% by CAL

What is an FDA & what does it cover?

The GESSAR II FDA is issued pursuant to Appendix O to 10 CFR Part 50. The review covers the technical information required by the appropriate sections of 50.34(b). The FDA documents the staff's and the ACRS's review of the subject design and is to be utilized by and relied upon by the staff and the ACRS in their review of any individual facility license application which references the design. An FDA does not constitute a commitment to issue a permit or license.

The details and descriptions of the design that have been reviewed by the Staff and the ACRS are presented in GESSAR II, its amendments (which are identified in the application) and the SER and its supplements. The SERs and the FDA identify the status of the application and approval. Changes to the design following the issuance of the FDA can only be approved through the process of amending the FDA.

A PRESENTATION TO ACRS COMMITTEE
ON GESSAR II

WASHINGTON, D.C

GENERAL ELECTRIC COMPANY
SEPTEMBER 12, 1985

GESSAR II

o CONSEQUENCES AND RISK FROM INTERNAL EVENTS

o CORE DAMAGE FREQUENCY: 4.3×10^{-6} /REACTOR YEAR

o RISK: 1.7×10^{-5} LATENT FATALITIES/REACTOR YEAR

o AREAS MOST CRITICAL TO INTERNAL EVENT CONSEQUENCES

o GESSAR RISK RELATIVELY INSENSITIVE (<FACTOR OF TWO) TO:

- CORE HEATUP/HYDROGEN GENERATION
- PRIMARY SYSTEM RETENTION
- EARLY RPV FAILURE
- CONCRETE COMPOSITION

o GESSAR RISK MODERATELY SENSITIVE (FACTOR OF 2-5) TO:

- LATE TELLURIUM RELEASE
- HIGH POPULATION SITE
- SUPPRESSION POOL SCRUBBING

GESSAR II

o CONSEQUENCES AND RISK FROM EXTERNAL EVENTS

<u>INITIATOR</u>	<u>CORE DAMAGE FREQUENCY</u>	<u>RISK</u>
SEISMIC	4×10^{-7}	9×10^{-7}
FIRE	7.5×10^{-8}	2.6×10^{-7}
FLOOD	6.4×10^{-9}	1.7×10^{-8}

o AREAS MOST CRITICAL TO SEISMIC EVENT CONSEQUENCES

o SEISMIC HAZARD CURVE

o POOL BYPASS POTENTIAL

- STRUCTURAL BUILDING FAILURES CAUSING PIPE BREAKS
- ISOLATION VALVE RELIABILITY
- DRYWELL FAILURE

MAJOR UNCERTAINTIES IN INTERNAL AND EXTERNAL EVENTS

- o SEISMIC HAZARD CURVE
- o COMPONENT AND STRUCTURAL FRAGILITIES
- o PARTICLE SIZE DISTRIBUTION
- o HUMAN ERROR

MEETING HANDOUT

Meeting No. 305	Agenda Item 7.2	Handout No. 1 - Addendum
Title ANTICIPATED ACRS ACTIVITIES - 306TH ACRS MEETING, OCTOBER 12-14, 1985		
Authors R. F. Fraley		
List of Documents Attached Memo, Browning, Director Division of Waste Mgt. to R. F. Fraley dtd. 9/11/85 <u>NRC STAFF VIEW ON IMPLEMENTATION OF THE EPA HLW STANDARDS</u> (refers to Item 12 in Handout 1)		
Instructions to Preparer 1. Punch holes 2. Paginate attachments 3. Place copy in file box		From Staff Person R. F. Fraley



UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

11 885

REACTOR SAFEGUARDS, U.S.N.R.C.

MEMORANDUM FOR: R. F. Fraley, Executive Director
Advisory Committee on Reactor Safeguards

FROM: Robert E. Browning, Director
Division of Waste Management

SUBJECT: NRC STAFF VIEWS ON IMPLEMENTATION OF THE EPA HLW STANDARDS

Your memorandum of July 29, 1985 to William J. Dircks forwarded the ACRS comments on the EPA standards for disposal of high-level radioactive wastes. I would like to provide you with additional information regarding the staff's views on EPA's standards and on implementation of those standards by the NRC.

The ACRS's concerns are capsulized in the following paragraph from David A. Ward's July 17, 1985 memorandum to Chairman Palladino:

It is our understanding that the NRC Staff has concurred with the proposed EPA standards, including the use of a probabilistic approach on radionuclide release limits. In view of the importance of the ability of the NRC to determine compliance with the EPA standards in licensing a high-level waste repository, we recommend that the Commission assure itself that the NRC Staff is correct in endorsing this approach. We believe that demonstration of such compliance will be extremely difficult and that the proposed standards are unduly restrictive.

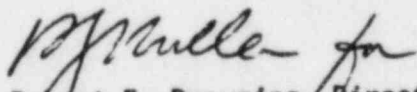
The NRC staff recognizes that use of numerical probabilities by EPA represents a novel approach for setting environmental standards. NRC comments on the proposed standards stated "The numerical probabilities in (the proposed standards) would require a degree of precision which is unlikely to be achievable in evaluating a real waste disposal system." In discussions following publication of the proposed standards, the NRC staff explained to EPA the difficulties foreseen in trying to implement a standard containing numerical probabilities. As a result of these discussions, EPA has added a new paragraph to Section 191.13 of the standards which reads as follows:

"Performance assessments need not provide complete assurance that the requirements of 191.13(a) will be met. Because of the long time period involved and the nature of the events and processes of interest, there will inevitably be substantial uncertainties in projecting disposal system performance. Proof of the future performance of a disposal system is not to be had in the ordinary sense of the word in situations that

deal with much shorter time frames. Instead, what is required is a reasonable expectation, on the basis of the record before the implementing agency, that compliance with 191.13(a) will be achieved."

The staff considers that this wording (which conforms closely to §60.101(a)(2) of the Commission's regulations) sets reasonable bounds on the degree of assurance required for estimates of the likelihood and consequences of potentially disruptive events and processes. The Commission will not need to place sole reliance on probabilistic analyses when evaluating repository safety but, rather, will have considerable opportunity to employ its more traditional analytical and engineering methods. The staff considers that the specific performance objectives of 10 CFR Part 60, the detailed siting and other qualitative criteria of 10 CFR Parts 60 and 960, and the technical positions under development by the NRC staff will help assure that the appropriate balance is struck between use of traditional analytical and engineering methods and probabilistic analyses in making licensing findings. Although the staff continues to believe that the probabilistic nature of the standards will pose a significant challenge, the staff considers that the standards, in the current form, can be implemented in a licensing review.

I hope that this information proves helpful in explaining the staff's views regarding implementation of the EPA standards by the NRC.


Robert E. Browning, Director
Division of Waste Management

NRR STAFF PRESENTATION TO THE ACRS

SUBJECT: GESSAR-II PRA SEVERE ACCIDENT CONSEQUENCE RESULTS

DATE: SEPTEMBER , 1985

PRESENTER: ~~W. BRAD TARDIN~~ Jack Rosenthal

PRESENTER'S TITLE/BRANCH/DIV: REACTOR SYSTEMS BRANCH
DIVISION OF SYSTEMS INTEGRATION

PRESENTER'S NRC TEL. NO.: 492-~~9447~~

SUBCOMMITTEE: GESSAR-II

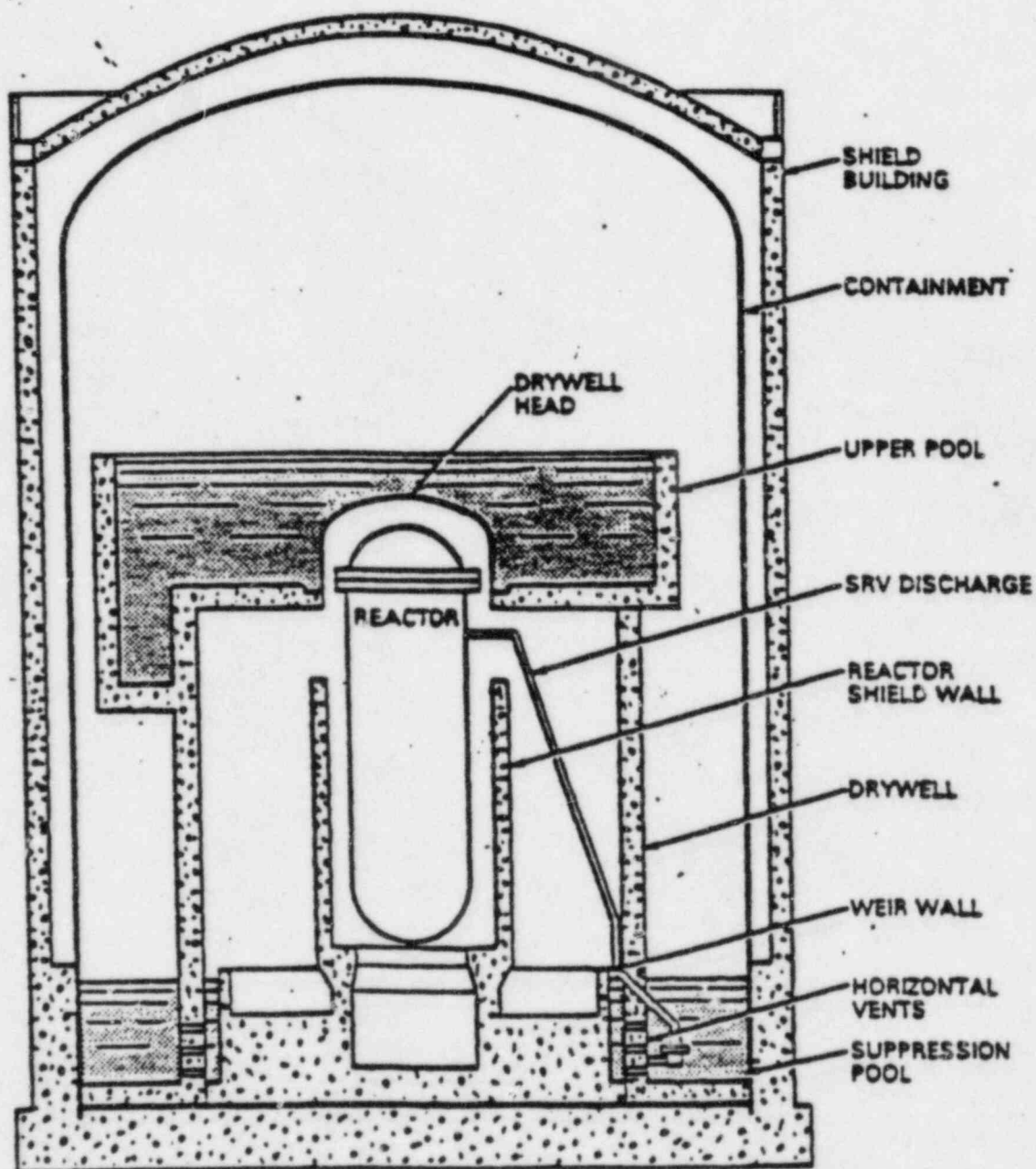
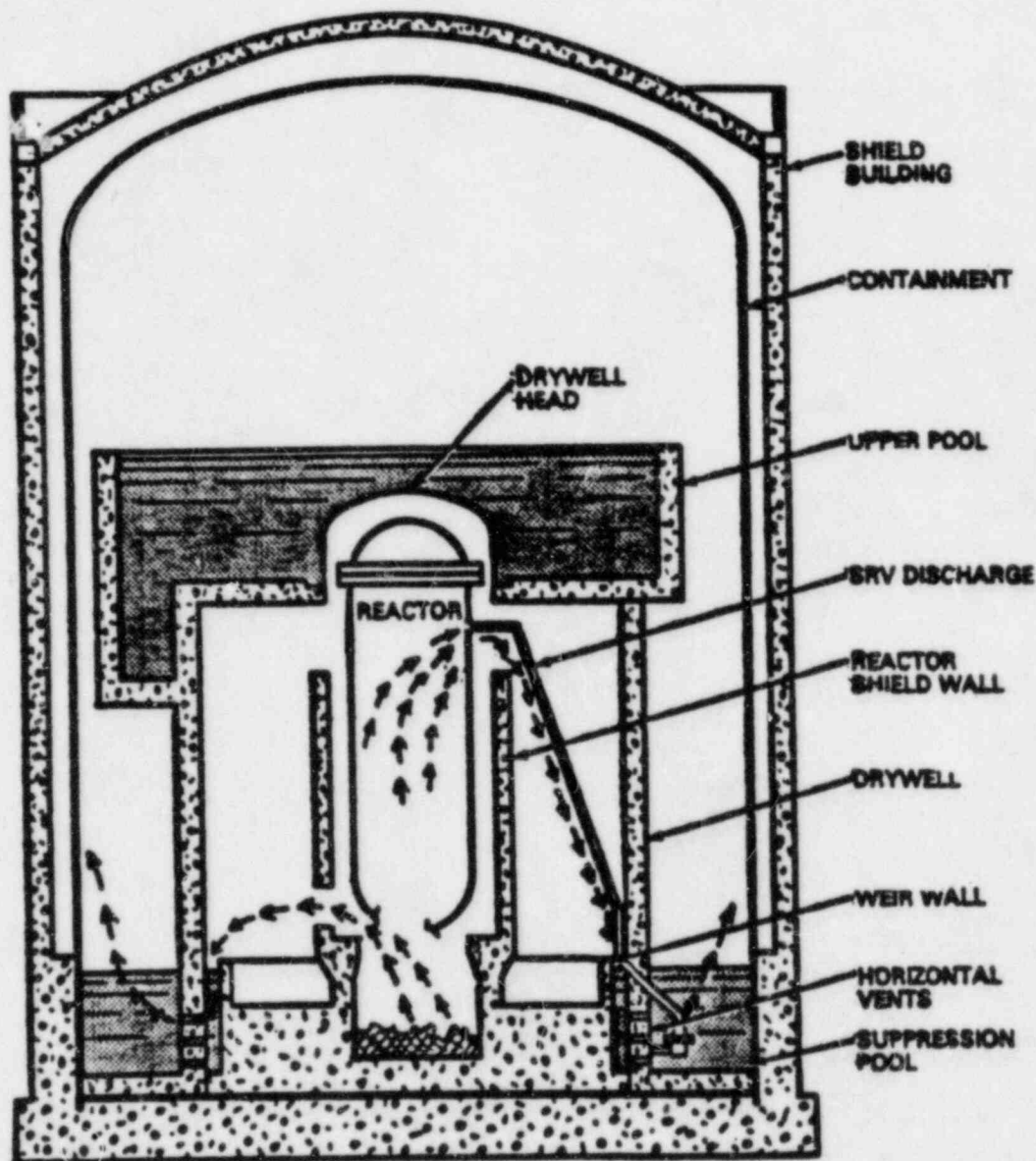


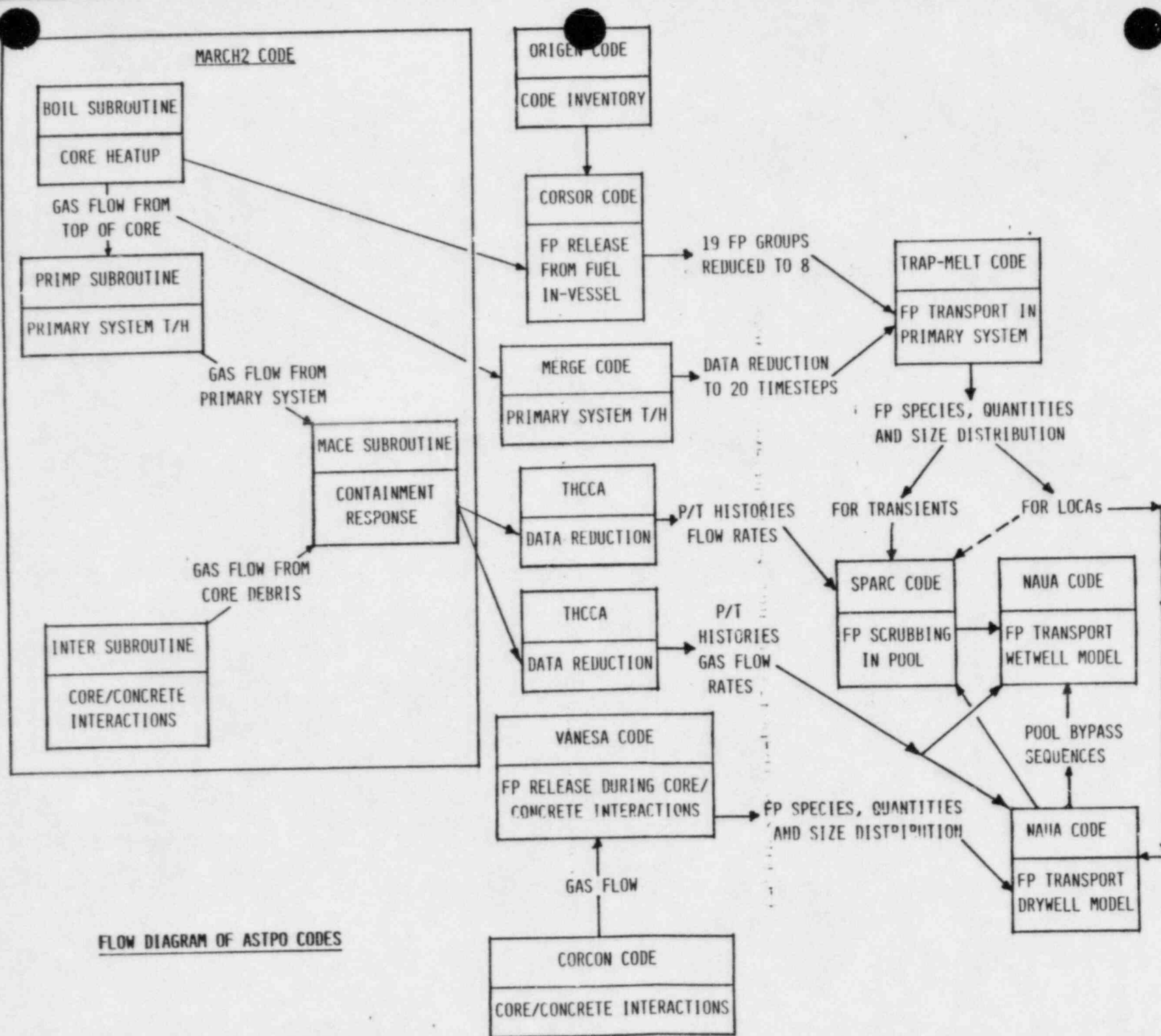
Figure 15.1 Principal features of MARK III containment



In-vessel release passes through safety/relief valve (SRV) lines, is scrubbed in suppression pool before entering secondary containment, and then is released to the environment.

Ex-vessel (core/concrete vaporization) release passes through horizontal vents into the pool and is also scrubbed.

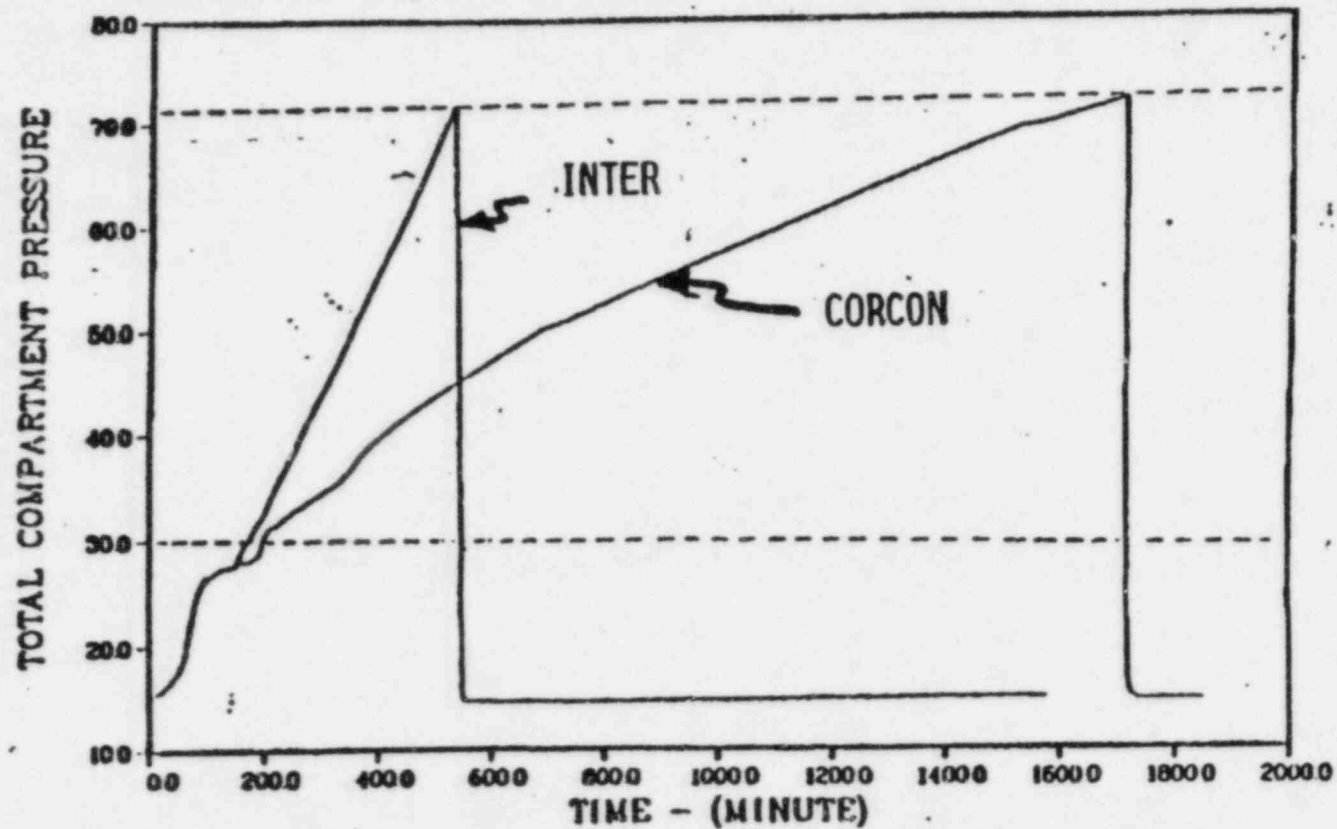
Figure 15.1 GESSAR II Mark III containment: typical fission product release pathways with drywell intact



COMPARISON BETWEEN BNL SENSITIVITY STUDY AND BNL
MECHANISTIC ANALYSIS (CLASS I LATE FAILURE COMPLETE
POOL SCRUBBING)

SPECIES	BNL SENSITIVITY (HIGH) (TR=13 HR)	BNL MECHANISTIC (TR=28 HR)	BNL SENSITIVITY (LOW) (TR=13 HR)
XE-KR	1.0	1.0	1.0
OI	3.0(-4)	3.0(-4)	3.0(-4)
CsI	1.8(-3)	3.0(-4)	1.0(-5)
CsOH	2.6(-3)	3.3(-4)	7.9(-6)
TE	2.9(-3)	1.2(-3)	5.4(-6)
SR	1.6(-3)	9.9(-4)	3.8(-6)
BA	6.6(-4)	5.6(-4)	3.8(-6)
Ru, Mo, Rh	6.2(-6)	1.0(-8)	5.6(-8)
Tc	1.9(-3)	1.0(-8)	5.1(-6)
CE, Pu, NP	4.8(-5)	9.0(-5)	5.3(-9)
LA, Y, SM PR, ND	9.6(-5)	9.4(-5)	5.5(-10)

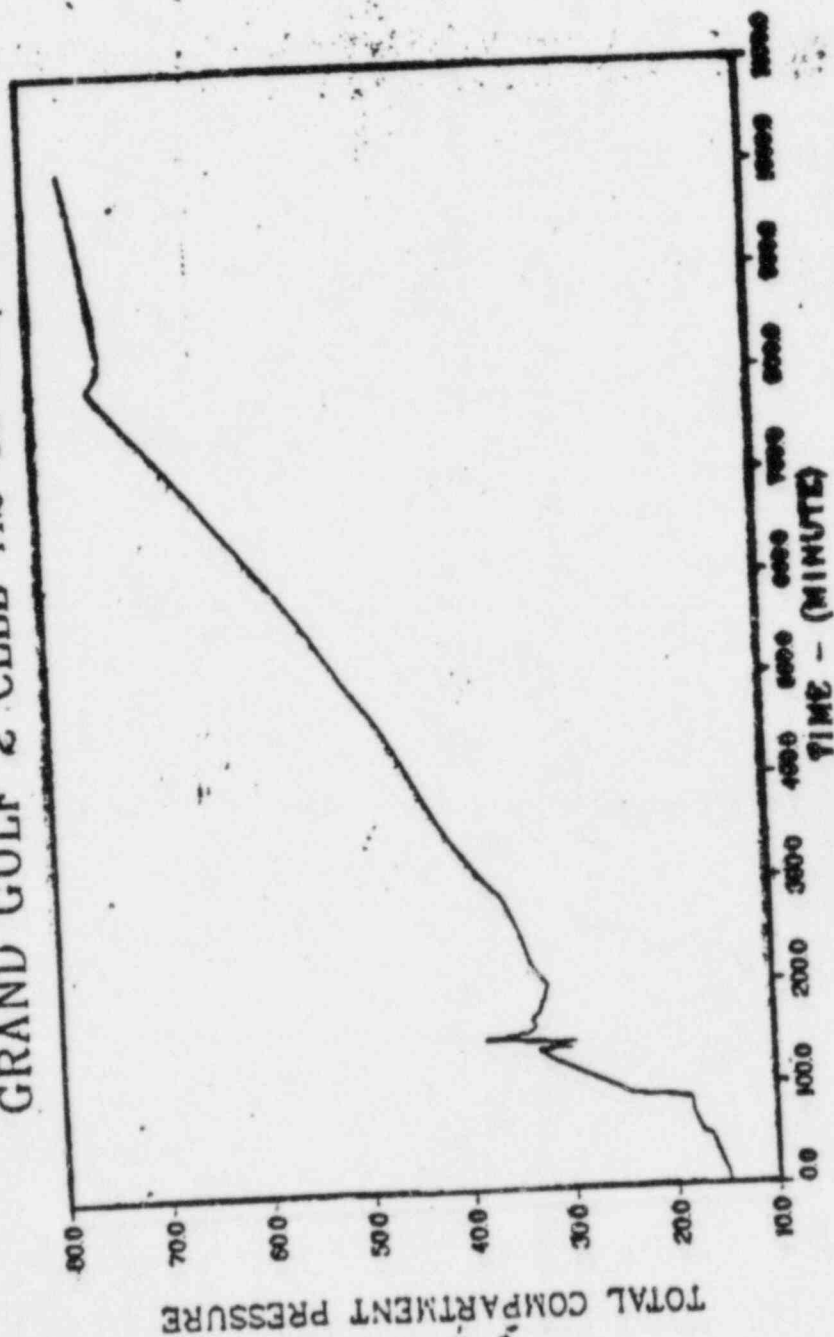
GESSAR2 TQUXLF CORCON-MARCH2-151 5-21-85



VOLUME NO. 1

11.17.57 14.2 3/28, 1961 200-8150121, 200-8150121, 200-8150121, 200-8150121

GRAND GULF 2 CELL H2 50 LB/MIN

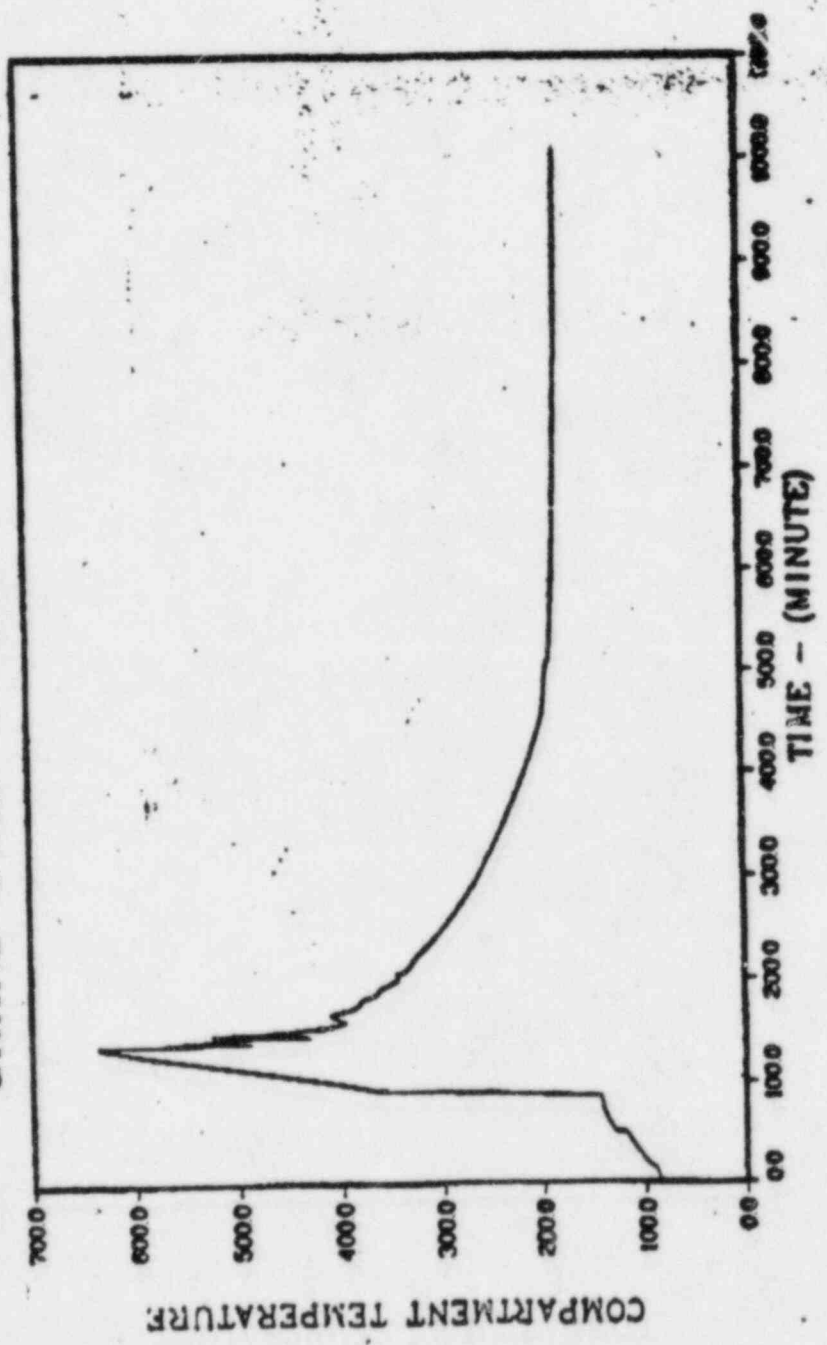


VOLUME NO. 2

Well

NO. 1 11.0.50 1000 3 100 100 20-0151111, 0005-1001

GRAND GULF 2 CELL H2 50 LB/MIN



VOLUME NO. 2

11.0.50-11

MARK 3 CONTAINMENT FAILURE MODES VERSUS TYPE OF SEVERE ACCIDENT
NO IGNITERS

	DRYWELL FAILURE DUE TO H ₂ BURNS	NETWELL FAILURE DUE TO H ₂ BURNS	LATE NETWELL FAILURE DUE TO STEAM OR NON-CONDENS. GAS PRODUCTION	EARLY NETWELL FAILURE DUE TO STEAM PRODUCTION
LOCA (1%)	.03 1-SB-E1	.42 1-T-E3	.55 1-T-L3	
STATION BLACKOUT (79%)	.50 1-T-I2	.50 1-T-E3		
LOSS OF CONTAINMENT HEAT REMOVAL (10%)				1.0 2-T-B3
ATWS (8%)				1.0 ATWS

Table 15.1 Conditional consequences predicted by the staff for internally initiated events and probability of occurrence with and without UPPS, per reactor year

Release category ^a	Early fatality	Early injury	Latent fatality	Person-rem	Probability	
					w/o UPPS	w/UPPS
1-T-L3	0	0	40	7 x E5**	3 x E-6	9 x E-7
1-T-E3	0	0.0005	200	3 x E6	8 x E-6	1 x E-6
1-T-I2Q	0	3	200	3 x E6	1 x E-5	1 x E-6
2-T-B3	0	0	300	5 x E6	4 x E-6	4 x E-7
ATWS	0	1	400	6 x E6	3 x E-6	3 x E-6
1-T-I2	0	6	500	8 x E6	3 x E-6	3 x E-7
1-SB-E1	0.006	10	600	9 x E6	1 x E-9	1 x E-9

^aSee definitions in Table 15.15.

**7 x E5 = 7 x 10⁵.

Notes:

- (1) All conditional mean consequences were calculated using the upper range BNL source term values described in SSER 2.
- (2) The calculations assumed the Shippingport site, with public evacuation within 10 miles and relocation 12 hours after plume passage.
- (3) Mean consequences were computed over 91 different weather conditions.

Table 15.2 Conditional consequences predicted by the staff for externally initiated events (seismic) and probability of occurrence, per reactor year

Release category*	Early fatality	Early injury	Latent fatality	Person-rem	Probability	
					w/o UPPS	w/UPPS
1-T-L3	0.3	8	600	1 x E6**	3 x E-7	3 x E-7
ATWS	50	150	500	7 x E6	6 x E-6	6 x E-6
1-T-I2	70	200	600	9 x E6	6 x E-5	5 x E-5
1-SB-E1	100	300	700	11 x E6	1 x E-6	1 x E-6
S ₂ E _m	250	900	600	8 x E6	1 x E-7	1 x E-7

*See definitions in Table 15.15.

**1 x E6 = 1 x 10⁶.

Notes:

- (1) All conditional consequences were calculated using upper range source term values.
- (2) The Shippingport site was assumed.
- (3) No public evacuation was assumed; relocation 24 hours after plume passage and no sheltering for severe earthquakes, as specified in Case 3 of the Limerick Final Environment Statement (NUREG-0974), were assumed.
- (4) The S₂E_m category was approximated using BMI-2104 information (Battelle, 1984).

SEISMIC RISK IS DOMINATED BY
STATION BLACKOUT WITH CONSEQUENTIAL
FAILURE TO ISOLATE ALL FLUID SYSTEMS

- BINNED IN 1-T-12
- MAJOR CONTRIBUTION. AT .5g - .6g
- HIGH CONFIDENCE NEEDED THAT IGNITERS
SURVIVE AT LEAST .6g

SEISMIC RISK, PERSON-REMS PER UNIT YEAR

RELEASE CATEGORY	TABLE 15.11 SER SUPPLEMENT 4			EFFECT OF GESSAR CONTAINMENT EVENT TREE FOR TOTAL LOSS OF POWER		
	WITHOUT UPPS	WITH UPPS	UPPS AND IGNITIERS	WITHOUT UPPS	WITH UPPS	UPPS AND IGNITERS
1-SB-E1	13	13	--	13	13	--
1-T-L3	0.3	0.3	0.3	30	26	26
1-S2 (MAX)	0.5	0.5	0.5	0.5	0.5	0.5
ATWS	43	43	43	43	43	43
I-T-I2	526	456	--	79	69	--
I-T-E3	--	--	170	47	41	65
V-EVENT	12	12	12	12	12	12
RHR PIPE BREAK	31	30	30	31	30	30
MASSIVE FAILURE	7	7	7	7	7	7
TOTAL	632	562	260	263	241	184

RESULTS / CONCLUSIONS

o RISK PREDICTED FOR GESSAR-11 IS LOW
(INTERNAL & EXTERNAL EVENTS)

REASONS: 1. UK3 CONTAINMENT WITH SUPPRESSION
POOL IS EFFECTIVE AT FISSION
PRODUCT REMOVAL

2. USE OF IMPROVED DATA & METHODS
FOR SEVERE ACCIDENT EVALUATION

o LARGE UNCERTAINTIES EXIST IN SOURCE TERMS

-DOMINATES ANALYSIS RESULTS

-CAN NOT DEFINE STATISTICAL DISTRIBUTIONS

OR BEST-ESTIMATE VALUES

-RANGE OF VALUES USED APPEARS APPROPRIATE

-USE OF UPPER-RANGE VALUES APPEARS APPROPRIATE ...

RESULTS / CONCLUSIONS

(CONTINUED)

- o EFFECTIVENESS OF SUPPRESSION POOL SCRUBBING MAKES
POTENTIAL FOR POOL BYPASS IMPORTANT TO REVIEW
- o RISK FROM EXTERNAL EVENTS (MAINLY SEISMIC)
IS PREDICTED TO BE GREATER THAN RISK FROM
INTERNAL EVENTS.

AREAS MOST CRITICAL TO INTERNAL EVENTS CONSEQUENCES

- SOURCE TERM VALUES
- POTENTIAL FOR SUPPRESSION
POOL BYPASS
- SITE CHARACTERISTICS

AREAS MOST CRITICAL TO SEISMIC EVENT CONSEQUENCES

- SOURCE TERM VALUES
- POTENTIAL FOR SUPPRESSION POOL
BYPASS
- EVACUATION OF PUBLIC
- SITE CHARACTERISTICS

QUALIFICATIONS FOR RESULTS

- LARGE UNCERTAINTIES EXIST IN ANALYSES
 - SOURCE TERMS
 - CONTAINMENT BEHAVIOR / ACCIDENT PROGRESSION
- SOME SEVERE ACCIDENTS HAVE NOT YET BEEN FULLY ANALYZED
 - BWR EVENT V (RCC STEAMLINER BREAK WITHOUT ISOLATION)
 - RHR SUCTION LINE BREAK

Table 15.15 Release categories

Release category	Description
1-T-L3	Class 1 core-melt transient (e.g., station blackout) with late containment failure as a result of overpressurization from gases generated during core-concrete interaction.
1-T-E3	Core-melt transient as above with early containment failure resulting from local or global hydrogen detonation. However, the drywell is assumed to remain intact and pool scrubbing is maintained.
1-T-I2Q	Core-melt transient. Station blackout with power restored after 1 hour. Global hydrogen detonation with drywell failure and potential pool bypass; however most fission products are assumed to be released before the vessel fails and so are retained in the pool. Also, core debris is assumed to be quenched.
1-T-I2	Same as 1-T-I2Q but without quench.
1-T-E2	Variations of above core-melt transients where "E" represents early containment failure, "I" intermediate time, and "L" late. The "1", "2", and "3" refer to partial, intermediate, and continuous scrubbing as defined in Table 15.11 of SSER 2. "Q" refers to quenched ex-vessel core debris.
1-T-E2Q	
1-T-I3	
1-T-L2	
1-SB-E1	Small-break core-melt transient with early containment failure (drywell) from hydrogen detonation and bypass of suppression pool.
1-SB-E1Q	Same as above but with quench of ex-vessel core debris.
1-SB-E3	Same as above but drywell remains intact and there is no pool bypass.
1-SB-L1	Small-break core-melt transient with late overpressurization failure of containment and partial bypass of the pool.
1-SB-L3	Same as 1-SB-L1 but with no bypass.
II-T-B3	Class 2 core-melt transient with initial failure of containment heat removal causing overpressurization and failure of containment. Core melt and vessel failure follow the containment failure. No pool bypass.
ATWS	Anticipated transient without scram and core melt.
S ₂ E _m	Core-melt accident caused by a very severe earthquake. Early containment and drywell failure with suppression pool bypass. Analysis values were approximated using BMI-2104 information (Battelle, 1984).

NRR STAFF PRESENTATION TO THE ACRS

SUBJECT: GESSAR II STAFF REQUIRED INTERFACES

DATE: SEPTEMBER 11, 1985

PRESENTER: DINO C. SCALETTI

PRESENTER'S TITLE/BRANCH/DIV: PROJECT MANAGER / SSPB / DL

PRESENTER'S NRC TEL. NO.: 492-9787

SUBCOMMITTEE: GESSAR II

SEVERE ACCIDENT INTERFACES

Supplement #2

15.6.2 Quality assurance and interface requirements

Utility applicants referencing GESSAR II must provide an evaluation to support the PRA interfaces and assumptions to demonstrate that the PRA's applicable.

15.6.2.3 Internal and external flooding analysis (Page 15-19)

Internal flooding-analysis should consider that rupture of lines to the suppression pool has the potential for bypass pathway. The impact on plant risk must be addressed.

External flooding - provide PMF information required by the SPP.

15.6.2.3 Aircraft Strike (page 15-19)

Demonstrate that the probability of aircraft impact is less than 10^{-7}

15.6.2.3 Hazardous Materials

Provide information that the risk from hazardous materials is low. Utility applicants will provide a determination of the design-basis events with probabilities of greater than 10^{-7} per year and have potential consequences serious enough to effect the safety of the plant to the extent that 10 CFR 100 guidelines could be exceeded.

15.6.2.3 Snow and Ice Loading (page 15-20)

Assess the risk impact from snow and ice loading

Appendix C Systems interaction (USI-17 (page 15-20)

- (1) Provide system-level failure modes analyses
- (2) Include RPS, RCIC, RHR, Remote shutdown SBT and HVAC systems in the FMEA.
- (3) Include BOP systems in the analysis
- (4) Analysis of spatially coupled systems

Appendix C Behavior of BWR Mark III Containment, GSI B-10

Address staff acceptance criteria for LOCA-related pool dynamic loads identified in NUREG-0978 and in Section 6.2.1.8.3 in the GESSAR II SER

Appendix C Reliability of open cycle service ~~for~~ water systems, GSI 51, (page 19)

To be addressed by utility applicants

Appendix C Probability of core melt due to CCW system, GSI 65, (page 20)

The major portion of the CCW is outside the scope of GESSAR II

A utility applicant must show core melt and risk from an accident will result in no significant change to PRA.

Appendix G CFR rule items

Provide required information required by 10 CFR 50.34(f) for those items outside GESSAR II scope.

15.6.2.3(1.5) Critical component and structures list. (page 15-12)

Develop a critical components and structures list for the plant with due consideration of Table 15.1. Perform fragility analyses of all critical structures and components and show that they are bounded by the values presented in the GESSAR II seismic risk study, and clearly indicate all supporting assumptions and calculations incorporated into the fragility analyses. In this context, bounding the fragility value means that the plant specific median values should be greater than or equal to the GESSAR II median values and that the plant specific logarithmic standard deviation values should be below or equal to the corresponding GESSAR II values. For critical components not included in the GESSAR II list, an applicant should satisfy the Case 1 alternate fragilities presented in supplement 3 (Table 15.2).

Site specific hazard function analysis

Perform a site specific hazard function analysis, and justify that the mean and mean plus one standard deviation of the site specific hazard are bounded by the mean and mean plus one standard deviation GESSAR II seismic hazard function as indicated in Table 2-3 of the "GESSAR II Seismic Event Uncertainty Analysis," December 1983.

Seismic analysis interface assumptions

For the balance of plant features not included in the GESSAR II or the Case 1 analysis, and any plant specific seismic vulnerability to be determined from a plant specific walkdown, show that the as-built plant satisfies the assumptions utilized by the GESSAP II analysis.

In the event that these analyses indicate that the above conditions are not met, the utility applicant shall demonstrate that this does not result in any significant increase in risk.

Supplement #4

15.6 Containment venting procedures, (page 15-2)

Provide guidelines and procedures for containment venting below the ultimate containment pressure-carrying capability of 83 PSIG

15.6.3.4.4 RCIC room cooling

Utility applicants must investigate what actions are available to facilitate RCIC room cooling for extended operation during a station blackout.

Appendix C Safety implications of control systems, USI A-47, (page 3)

Provide the necessary evaluation of control systems required by NUREG-0979 and that will be required by resolution of USI A-47.

Appendix C Interfacing LOCA, GSI 105, (page 10)

Demonstrate the intended design capability of the isolation valves, at least on a prototype basis, by performing a closing and opening test with full design differential pressure and flow across the valve disk. Such a design test is recommended in addition to the leak and operability testing of isolation valves as required by the BWR Standard Technical Specifications.

In addition to the interfaces listed above the staff will condition the FDA to require the following modifications discussed in SSER Section 15.6.3.5.

- 1) Seismic upgrade to UPPS
- 2) Dedicated power supply to hydrogen igniter system
- 3) 10-hour station batteries
- 4) Ability to power a dc battery charger from the backup igniter power supply

US1 A-43, CONTAINMENT EMERGENCY SUMP PERFORMANCE

PROPOSED CHANGES TO RG 1.82

AND

RESOLUTION STATUS

PREPARED FOR:

305TH ACRS MEETING

BY

A. W. SERKIZ, TASK MANAGER

GENERIC ISSUES BRANCH

DIVISION OF SAFETY TECHNOLOGY

OFFICE OF NUCLEAR REACTOR REGULATION

SEPTEMBER 12, 1985

TECHNICAL BACKGROUND

- 1) THE TECHNICAL FINDINGS RELATED TO USI A-43 ARE REPORTED IN NUREG-0897, REVISION 1B WHICH WILL BE PUBLISHED UPON RESOLUTION OF THIS ISSUE.
- 2) ADDITIONS AND MODIFICATIONS HAVE BEEN MADE TO REFLECT: A) INPUTS RECEIVED FOR NUREG-0897 DURING THE "FOR COMMENT" PERIOD, B) RESULTS OF ADDITIONAL EXPERIMENTS AND C) ADDITIONAL INFORMATION RECEIVED FROM THE DIAMOND POWER COMPANY AND OWENS-CORNING FIBERGLASS, INC.
- 3) THESE FINDINGS REVEAL A NEED TO REVISE RG 1.82. IN PARTICULAR THE 50% SCREEN BLOCKAGE CRITERION CONTAINED IN SECTION C.7 OF THE ACTIVE VERSION IS REPLACED WITH A REQUIREMENT TO ASSESS DEBRIS BLOCKAGE EFFECTS ON A PLANT SPECIFIC BASIS.
- 4) THE ACRS HAS BEEN PROVIDED COPIES OF THE PROPOSED RG 1.82, REVISION 1, IN COMPARATIVE TEXT. THIS GUIDE HAS ALSO BEEN ISSUED TO PREVIOUS RESPONDEES WHO PROVIDED REVIEW COMMENTS.

OVERVIEW OF REVISIONS TO RG 1.82

- 1) RG 1.82 HAS BEEN REVISED TO INCLUDE BOTH BWRs AND PWRs. PROVISION FOR POST-LOCA RECIRCULATION CAPABILITY IS GENERIC TO BOTH TYPES OF REACTORS.
- 2) THE CURRENT 50% BLOCKAGE CRITERION HAS BEEN DELETED; GUIDANCE FOR ASSESSING PLANT SPECIFIC DEBRIS BLOCKAGE EFFECTS IS PROVIDED IN APPENDIX A.
- 3) THE RG HAS BEEN REVISED TO REFLECT SUMP (OR SUCTION INLET) HYDRAULICS FINDINGS AND REMOVES VORTEX OBSERVATIONS AS THE BASIS TO QUANTIFY AIR INGESTION LEVELS. APPENDIX A ALSO PROVIDES CONSERVATIVE GUIDELINES FOR ESTIMATING POTENTIAL AIR INGESTION LEVELS BASED ON FULL SCALE TESTS.
- 4) THE RG HAS BEEN REVISED TO REQUIRE ASSESSMENT OF DEBRIS AND PARTICULATE EFFECTS ON RHR AND CSS PUMP BEARING AND SEAL ASSEMBLIES.

STATUS OF IMPLEMENTATION OF RG 1.82, REVISION 1

- 1) RG 1.82, REV. 1 HAS BEEN REVISED AND OBTAINED DURING THE COURSE OF RESOLVING USI A-43 TO REFLECT TECHNICAL FINDINGS.
- 2) IMPLEMENTATION IS CONCURRENT WITH THE RESOLUTION OF USI A-43.
- 2) RG 1.82, REVISION 1 WOULD BECOME EFFECTIVE 6 MONTHS FOLLOWING ISSUANCE OF THE GUIDE AND WOULD APPLY TO FUTURE CP APPLICATIONS AND PRELIMINARY DESIGN APPROVALS (PDAs) THAT ARE DOCKETED AFTER SIX (6) MONTHS OF ISSUANCE, AND APPLICATIONS FOR FINAL DESIGN APPROVALS (FDAs) THAT HAVE NOT RECEIVED APPROVAL AT SIX (6) MONTHS FOLLOWING ISSUANCE OF THE RG.

CURRENT RESOLUTION STATUS OF USI A-43

- 1) A REVISED REGULATORY ANALYSIS HAS BEEN PREPARED (NUREG-0869, REVISION 1B, JUNE 1985 DRAFT).
- 2) THE ACRS COMBINED FLUID DYNAMICS/ECCS SUBCOMMITTEE WAS BRIEFED ON 8/27/85 REGARDING CHANGES TO RG 1.82 AND THE RESOLUTION STATUS OF USI A-43.
- 3) A CRGR MEETING WAS HELD ON 9/9/85 TO DISCUSS THE PROPOSED RESOLUTION ACTIONS. AGREEMENT WAS REACHED TO PROCEED WITH THE RECOMMENDED ACTIONS, WITH ALSO THE UNDERSTANDING THAT THE RG & SRP IMPLEMENTATION WORDING WOULD BE REVISED TO MORE CLEARLY REFLECT THE APPLICABILITY OF THESE REGULATORY CHANGES.

REVISED IMPLEMENTATION LANGUAGE

DUE TO CONCERNS RAISED REGARDING IMPLEMENTATION LANGUAGE IN THE PROPOSED REVISIONS TO RG 1.82 AND SRP SECTION 6.2.2, THE FOLLOWING LANGUAGE IS PROPOSED AS A SUBSTITUTE:

"IS APPLICABLE TO:

- 1) CONSTRUCTION PERMIT APPLICATIONS AND PRELIMINARY DESIGN APPROVALS (PDAs) THAT ARE DOCKETED AFTER SIX (6) MONTHS FOLLOWING ISSUANCE OF REGULATORY GUIDE 1.82, REVISION 1.
- 2) APPLICATIONS FOR FINAL DESIGN APPROVAL (FDAs), FOR STANDARDIZED DESIGNS WHICH ARE INTENDED FOR REFERENCING IN FUTURE CONSTRUCTION PERMIT APPLICATIONS, THAT HAVE NOT RECEIVED APPROVAL AT SIX (6) MONTHS FOLLOWING ISSUANCE OF REGULATORY GUIDE 1.82, REVISION 1.

OUR INTENT IS TO MAKE CLEAR THAT RESOLUTION OF THIS USI WILL NOT IMPACT PLANTS ALREADY UNDER CONSTRUCTION.

PROPOSED RESOLUTION ACTIONS FOR USI A-43

- 1) ISSUE THE STAFF'S TECHNICAL FINDINGS (NUREG-0897, REVISION 1B) FOR USE AS A TECHNICAL INFORMATION SOURCE.
- 2) ISSUE SRP SECTION 6.2.2, REVISION 4 AND RG 1.82, REVISION 1. THESE REVISIONS REFLECT THE STAFF'S TECHNICAL FINDINGS REPORTED IN NUREG-0897, REVISION 1B. THIS REVISED LICENSING GUIDANCE WOULD APPLY ONLY TO FUTURE CONSTRUCTION PERMIT APPLICATIONS, PRELIMINARY DESIGN APPROVAL (PDAs) AND FINAL DESIGN APPROVALS (FDAs) WHICH HAVE NOT RECEIVED APPROVAL AND WOULD BE EFFECTIVE 6 MONTHS FOLLOWING ISSUANCE.
- 3) ISSUE A GENERIC LETTER FOR INFORMATION ONLY TO ALL HOLDERS OF AN OPERATING LICENSE OR CONSTRUCTION PERMIT OUTLINING THE SAFETY CONCERNS REGARDING POTENTIAL DEBRIS BLOCKAGE AND RECIRCULATION FAILURE DUE TO INADEQUATE NPSH. IT IS SUGGESTED (BUT NOT REQUIRED) THAT LICENSEES UTILIZE RG 1.82, REVISION 1 AS GUIDANCE FOR CONDUCT OF THE 10 CFR 50.59 REVIEW FOR FUTURE PLANT MODIFICATIONS INVOLVING REPLACEMENT OF INSULATION ON PRIMARY SYSTEM PIPING AND/OR EQUIPMENT. IF, AS A RESULT OF NRC STAFF REVIEW OF LICENSEE ACTIONS ASSOCIATED WITH REPLACEMENT OR MODIFICATION TO INSULATION, THE STAFF DECIDES THAT SRP 6.2.2, REV. 4 AND/OR RG 1.82, REV. 1 CRITERIA SHOULD BE (OR SHOULD HAVE BEEN) APPLIED BY THE LICENSEE, AND THE STAFF SEEKS TO IMPOSE THESE CRITERIA, THEN THE NRC WILL TREAT SUCH AN ACTION AS A PLANT SPECIFIC BACKFIT PURSUANT TO 10 CFR 50.109.

EXCLUSION OF DYNAMIC LOADING EFFECTS ASSOCIATED WITH POSTULATED
PIPE BREAKS

ACRS SEPT. 12, 1985

- o INTRODUCTION R. J. BOSNAK 5 MIN.
- o HISTORY AND STATUS J. O'BRIEN 10 MIN.
OF RULECHANGES
(LIMITED & BROAD SCOPE)
- o FOREIGN PRACTICE J. O'BRIEN 5 MIN.
- o PLANT ACTIONS: R. KLECKER 10 MIN.
PWR MAIN LOOP
- o PLANT ACTIONS: R. J. BOSNAK 10 MIN.
ARBITRARY INTER-
MEDIATE BREAKS
- o TWO RECENT R. J. BOSNAK 10 MIN.
PROPOSALS
CRYSTAL RIVER-3 RCP SNUBBERS
BEAVER VALLEY-2-BOP (CONCEPTUAL)

INTRODUCTION

- o ACRS LETTER JUNE 14, 1983
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LEAKAGE DETECTION WITH MARGIN BEFORE CRACK IS UNSTABLE,
OK FOR PWR PRIMARY LOOP PIPING
 - o DECOUPLING SSE & LOCA-ANALYSIS BY LLL, VENDOR BY VENDOR
CAVEAT-HEAVY COMPONENT SUPPORT INTEGRITY
 - o ADVISE ACRS OF REGULATION CHANGES AND POSITIONS OF
FOREIGN REGULATORY BODIES
 - o EXTENSION TO OPERATING PLANTS CAVEAT-CLEAR ASSURANCE OF
QUALITY OF DESIGN & CONSTRUCTION

IMPLEMENTATION POLICY (NTOL'S)

SCHEDULAR EXEMPTIONS

ONCE LEAK BEFORE BREAK PERFORMANCE HAS BEEN ESTABLISHED
INCLUDING LEAKAGE DETECTION

CAN

ELIMINATE DYNAMIC LOADING EFFECTS:

1. PIPE WHIP, 2. JET IMPINGEMENT, 3. ASYMMETRIC
PRESSURIZATION TRANSIENTS (USI A-2), 4. BREAK
ASSOCIATED DYNAMIC TRANSIENTS IN UNBROKEN PORTIONS
MAINLOOP AND CONNECTED BRANCH LINES

PERMITS: REMOVAL WHIP RESTRAINT STRUCTURES, JET
IMPINGEMENT BARRIERS

CANNOT

CHANGE CONTAINMENT DESIGN, CHANGE ECCS DESIGN, CHANGE
EQUIPMENT QUALIFICATION (ENVIRONMENTAL PROFILE), CHANGE
HEAVY COMPONENT SUPPORT MARGINS

PLANT ACTIONS:

PWR MAIN LOOP REVIEW STATUS

OWNER'S GROUP

W A-2 FACILITIES

REVIEW COMPLETE, GENERIC LETTER 84-04
(TECH REVIEW COMPLETE FOR COOK 1, 2,
GINNA AND POINT BEACH 1, 2. NO RESPONSE
FROM REMAINING 11 FACILITIES.)

CESSAR, SYS. 80

REVIEW COMPLETE, LTR TO CE 10/11/84

B&W (BAW-1847)

REVIEW UNDERWAY

CESSAR II

REVIEW UNDERWAY

NTOL'S (22 PWR UNITS, MAIN LOOP PIPING ONLY)

FACILITIES

SER COMPLETE

EXEMPTION GRANTED

COMANCHE PEAK 1, 2

05/25/84

08/28/84 (UNIT 1,
IMP. SHIELDS)

VOGTLE 1, 2

08/20/84

02/05/85

CATAWBA 1, 2

09/20/84

04/23/85 (UNIT 2)

SOUTH TEXAS 1, 2

10/15/84

PALO VERDE 1, 2 & 3

10/31/84

CALLAWAY/WOLF CREEK

12/11/84

03/11/85 (WOLF CREEK)

MILLSTONE 3

01/15/85

06/05/85

BYRON 1, 2

01/15/85

BRAIDWOOD 1, 2

01/15/85

SEABROOK 1, 2

01/18/85

BEAVER VALLEY 2

01/18/85

SHEARON HARRIS 1

02/04/85

06/05/85

OTHER APPLICATIONS

PRAIRIE ISLAND 1

REVIEW UNDERWAY

INDIAN POINT 3

REVIEW UNDERWAY

(NO ACTION ON THE FOLLOWING PENDING BROAD RULE CHANGE)

NINE MILE POINT 1

SUBMITTAL RECEIVED (SECONDARY LINES)

CATAWBA 1, 2

SUBMITTAL RECEIVED FOR RHR, PRESSURIZER
SURGE AND ACCUMULATOR INJECTION LINES

PLANT ACTIONS:

ARBITRARY INTERMEDIATE BREAKS

- o BREAKS POSTULATED AT TERMINAL END AND AT INTERMEDIATE LOCATIONS WHERE STRESS OR USAGE FACTOR (FATIGUE) EXCEED SPECIFIED LIMITS
- o IN WELL DESIGNED SYSTEMS, THERE ARE NO INTERMEDIATE LOCATIONS EXCEEDING LIMITS. ARBITRARILY SELECT TWO.
- o PRC RECOMMENDS CAVEATS EMPLOYED AT START OF AIB PROGRAM BE DROPPED. (STRESS CORROSION CRACKING, LARGE UNANTICIPATED DYNAMIC LOADS, FATIGUE IN FLUID MIXING SITUATIONS
- o EQUIPMENT THROUGHOUT PIPING RUN QUALIFIED FOR NON-DYNAMIC EFFECTS OF A NON-MECHANISTIC PIPE BREAK WITH GREATEST CONSEQUENCES ON EQUIPMENT

PLANTS APPROVED (15)

- o CATAWBA 2, VOGTLE 1 & 2, SEABROOK 1, SHEARON HARRIS-1, SOUTH TEXAS 1 & 2, COMANCHE PEAK 1 AND 2, BYRON 1 & 2, BRAIDWOOD 1 & 2, BEAVER VALLEY 2, CLINTON 1
- o SRP 3.6.2 NOW BEING REVISED WITH CRGR PACKAGE IN PREPARATION

RECENT PRELIMINARY PROPOSALS

CRYSTAL RIVER-3

- o REACTOR COOLANT PUMP SUPPORTS: CURRENTLY: 32 1000-2000 KIP SNUBBERS; PROPOSED: 8 SMALLER SNUBBERS (400 KIP) AND 4 RIGID RESTRAINTS
- o BENEFITS: UNRELIABILITY OF LARGE SNUBBERS, ALARA, BETTER RELIABILITY OF SMALLER UNITS, IMPROVED THERMAL FLEXIBILITY
- o MARGINS REVISED, RELIABILITY INCREASED
- o NEEDS LIMITED SCOPE RULE CHANGE IN PLACE

BEAVER VALLEY-2

- o WHIPJET PROGRAM
DEMONSTRATE VIA TEST AND ANALYSIS
LEAK BEFORE BREAK APPROPRIATE FOR BOP SYSTEMS
- o ELIMINATE 136 BOP RUPTURE MITIGATION ITEMS BY
DEMONSTRATING LBB PERFORMANCE VIA FRACTURE MECHANICS
- o LBB PERFORMANCE FOR SYSTEMS NOT RELATIVELY IMMUNE TO
STRESS CORROSION, FATIGUE, AND LARGE DYNAMIC LOADS
- o NEEDS BROAD SCOPE RULE CHANGE IN PLACE

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PLANT ACTIONS:

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B&W (BAW-1847)

REVIEW UNDERWAY

CESSAR II

REVIEW UNDERWAY

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SER COMPLETE

EXEMPTION GRANTED

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05/25/84

08/28/84 (UNIT 1,
IMP. SHIELDS)

VOGTLE 1, 2

08/20/84

02/05/85

CATAWBA 1, 2

09/20/84

04/23/85 (UNIT 2)

SOUTH TEXAS 1, 2

10/15/84

PALO VERDE 1, 2 & 3

10/31/84

CALLAWAY/WOLF CREEK

12/11/84

03/11/85 (WOLF CREEK)

MILLSTONE 3

01/15/85

06/05/85

BYRON 1, 2

01/15/85

BRAIDWOOD 1, 2

01/15/85

SEABROOK 1, 2

01/18/85

BEAVER VALLEY 2

01/18/85

SHEARON HARRIS 1

02/04/85

06/05/85

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REVIEW UNDERWAY

INDIAN POINT 3

REVIEW UNDERWAY

(NO ACTION ON THE FOLLOWING PENDING BROAD RULE CHANGE)

NINE MILE POINT 1

SUBMITTAL RECEIVED (SECONDARY LINES)

CATAWBA 1, 2

SUBMITTAL RECEIVED FOR RHR, PRESSURIZER
SURGE AND ACCUMULATOR INJECTION LINES

PLANT ACTIONS:

ARBITRARY INTERMEDIATE BREAKS

- o BREAKS POSTULATED AT TERMINAL END AND AT INTERMEDIATE LOCATIONS WHERE STRESS OR USAGE FACTOR (FATIGUE) SPECIFIED LIMITS
- o IN WELL DESIGNED SYSTEMS, THERE ARE NO INTERMEDIATE LOCATIONS EXCEEDING LIMITS. ARBITRARILY SELECT 1
- o PRC RECOMMENDS CAVEATS EMPLOYED AT START OF AIB P DROPPED, (STRESS CORROSION CRACKING, LARGE UNANT DYNAMIC LOADS, FATIGUE IN FLUID MIXING SITUATIONS
- o EQUIPMENT THROUGHOUT PIPING RUN QUALIFIED FOR NON EFFECTS OF A NON-MECHANISTIC PIPE BREAK WITH GREA CONSEQUENCES ON EQUIPMENT

PLANTS APPROVED (15)

- o CATAWBA 2, VOGTLE 1 & 2, SEABROOK 1, SHEARON HARR TEXAS 1 & 2, COMANCHE PEAK 1 AND 2, BYRON 1 & 2, & 2, BEAVER VALLEY 2, CLINTON 1
- o SRP 3.6.2 NOW BEING REVISED WITH CRGR PACKAGE IN

RECENT PRELIMINARY PROPOSALS

CRYSTAL RIVER-3

- o REACTOR COOLANT PUMP SUPPORTS: CURRENTLY: 32 1000-2000 KIP SNUBBERS; PROPOSED: 8 SMALLER SNUBBERS (400 KIP) AND 4 RIGID RESTRAINTS
- o BENEFITS: UNRELIABILITY OF LARGE SNUBBERS, ALARA, BETTER RELIABILITY OF SMALLER UNITS, IMPROVED THERMAL FLEXIBILITY
- o MARGINS REVISED, RELIABILITY INCREASED
- o NEEDS LIMITED SCOPE RULE CHANGE IN PLACE

BEAVER VALLEY-2

- o WHIPJET PROGRAM
DEMONSTRATE VIA TEST AND ANALYSIS
LEAK BEFORE BREAK APPROPRIATE FOR BOP SYSTEMS
- o ELIMINATE 136 BOP RUPTURE MITIGATION ITEMS BY
DEMONSTRATING LBB PERFORMANCE VIA FRACTURE MECHANICS
- o LBB PERFORMANCE FOR SYSTEMS NOT RELATIVELY IMMUNE TO
STRESS CORROSION, FATIGUE, AND LARGE DYNAMIC LOADS
- o NEEDS BROAD SCOPE RULE CHANGE IN PLACE

FOREIGN PRACTICES RELATING TO PIPE RUPTURES
(UPDATED TO LATE 1984)

FEDERAL
REPUBLIC
OF
GERMANY

MAIN PRIMARY COOLANT CIRCUIT DEGB BREAK FOR ECCS, CONTAINMENT AND EQUIPMENT, NO DEGB BREAKS IN MAIN COOLANT LOOP OR MAIN STEAM OR MAIN FEEDWATER LINES INSIDE THE CONTAINMENT OF PWRs FOR REACTION FORCES OR JET FORCES. 10% FLOW AREA LONGITUDINAL RUPTURE STILL POSTULATED. PIPE WHIP RESTRAINTS BEING REMOVED.

ITALY

SWITCHED FROM USA PRACTICES TO FRG PRACTICES.

FOREIGN PRACTICES RELATING TO PIPE RUPTURES

(UPDATED TO LATE 1984)

CANADA

FULL GUILLOTINE BREAK WITH DISCHARGE AREA UP TO TWO TIMES CROSS-SECTIONAL AREA OF PIPE POSTULATED. BREAKS ARE POSTULATED IN HIGH ENERGY PIPING NOT REMOTE FROM ESSENTIAL SAFETY SYSTEMS. PIPE WHIP RESTRAINTS OF CRUSHABLE HONEYCOMB OFTEN USED. SOME DEPENDENCE ON USA PRACTICES.

FRANCE

ONLY HIGH ENERGY LINES BREAK, PIPE WHIP RESTRAINTS OF VARIOUS DESIGNS USED. VERY CLOSE TO USA PRACTICES.

JAPAN

ONLY HIGH ENERGY LINES BREAK, PIPE WHIP RESTRAINTS USED TO LIMIT MOTION. CLOSE TO USA PRACTICES. CONSTRUCTION OF PIPE WHIP RESTRAINTS IS EITHER STEEL BARS, ROLLED SHAPES OR BUILT-UP GIRDER BOX FRAMES.

SWEDEN

DOES NOT USE LEAK BEFORE BREAK, USES (WITH SOME EXCEPTIONS) TWO TIMES CROSS SECTIONAL AREA OF PIPE FOR DYNAMIC EFFECTS. PIPE WHIP RESTRAINTS USED. SOME DEPENDENCE ON USA PRACTICES.

UNITED KINGDOM

PIPE WHIP CRITERIA UNDER DEVELOPMENT FOR HIGH PRESSURE LINES. REGULATIONS TEND TO OMIT DISCUSSION OF PIPE RUPTURES. LEANING TOWARD USA PRACTICES.

ISSUES RELATED TO PUBLISHED PROPOSED LIMITED SCOPE RULE

- 0 ENVIRONMENTAL QUALIFICATION NOT SPECIFICALLY MENTIONED AS BEING EXCLUDED FROM CONSIDERATION, ALTHOUGH EXCLUSION OF ECCS AND CONTAINMENTS IS MENTIONED.
- 0 DEFINITION OF PWR PRIMARY SYSTEM PIPING NOT PROVIDED. SUGGESTED DEFINITION IS: "LARGE DIAMETER THICK WALLED PIPING DIRECTLY CONNECTING RPV, RCP AND SG"
- 0 POSSIBLE MODIFICATION OF HEAVY COMPONENT SUPPORT DESIGN ALLOWED IF HIGH CONFIDENCE IN RELIABILITY AND MARGIN IS ACHIEVED.
- 0 DEFINITION OF EXTREMELY LOW NOT GIVEN. SUGGESTED DEFINITION IS: "OF THE ORDER OF 10^{-6} PER REACTOR YEAR WHEN ALL RUPTURE LOCATIONS ARE CONSIDERED (FOR PWR RCL PIPING)".
- 0 AMENDMENT MAY OR MAY NOT INVOLVE AN UNRESOLVED SAFETY ISSUE. ALSO AUGMENTED LEAKAGE DETECTION MAY OR MAY NOT BE NEEDED.

RULEMAKING TO MODIFY GDC 4

SCHEDULE

	<u>LIMITED SCOPE</u>	<u>BROAD SCOPE</u>
	<u>RULE¹</u>	<u>RULE</u>
PROPOSED	JULY 85	JAN 86
FINAL	DEC 85	JUNE 86 ²

1. LIMITED SCOPE RULE BASED ON RESOLUTION OF USI A-2 PREVIOUSLY REVIEWED AND ENDORSED BY ACRS AND CRGR.
2. DEVELOPMENT OF NEW SRP 3.6.X BEGINS JUNE 1986 TO SPECIFY REQUIREMENTS AND ACCEPTANCE CRITERIA FOR IMPLEMENTING LEAK-BEFORE-BREAK.