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Title: Power Authority of the State of New York and Entergy Nuclear Fitzpatrick, LLC

Docket Number: 50-333-LT and 50-286-LT
ASLBP No.: 01-785-02-LT

Location: White Plains, New York

Date: Tuesday, March 13, 2001

Work Order No.: NRC-113 Pages 1-168

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1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ATOMIC SAFETY AND LICENSING BOARD

5 ----------X

6 IN THE MATTER OF: :

7 POWER AUTHORITY OF THE STATE : Docket Nos.

8 OF NEW YORK AND ENTERGY NUCLEAR : 50-333-LT

9 INDIAN POINT 3 LLC, AND ENTERGY : and 50-286-LT

10 NUCLEAR OPERATIONS, INC. : (Consolidated)

11 (James A. Fitzpatrick Nuclear : ASLBP No.

12 Power Plant and Indian Point : 01-785-02-LT

13 Nuclear Generating Unit No. 3) :

14 ----------X

15 Tuesday, March 13, 2001

16 9:30 a.m.

17 White Plains Public Library

18 100 Maritime Avenue

19 White Plains, NY 10601

20 BEFORE:

21 CHARLES BECHHOEFER, Administrative Judge

22 Presiding Officer

23 LEE DEWEY, Chief Counsel, ASLBP

24 ROLAND FRYE, Senior Attorney, OCAA

25 MICHELLE MCKOWN, Panel Attorney

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2 WITNESS PAGE

3 GEORGE W. COLLINS 38

4 JOSEPH T. HENDERSON 38

5 DAVID LOCHBAUM 62

6

7 E-X-H-I-B-I-T-S

Exhibit No.	Document	Mark	Recd
Licensee			
1	Henderson Written Testimony and Affidavit	40	40
2	Collins Written Testimony and Affidavit	42	42
CAN			
1	Lochbaum Written Testimony	66	66
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1	Fitzpatrick Safety Evaluation Report Non-proprietary Version	167	167
2	Indian Point 3 Safety Evaluation Report, Non-proprietary Version	167	167

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

2 (9:49 a.m.)

3 JUDGE BECHHOEFER: Good morning, ladies

4 and gentleman. I am here as Presiding Officer in this

5 proceeding to conduct and oral hearing.

6 I'd like to introduce the people. My name

7 is Charles Bechhoefer. I'd like to introduce the

8 people with me. On my right is Michelle McKown, who's

9 a legal assistant with the Atomic Safety Licensing

10 Board Panel. On my left is Lee Dewey, who's the Chief

11 Counsel of the Panel. And on my far left is Rowland

12 Frye, who's an attorney for the Commission itself and

13 has been working, to some extent, with me on this

14 proceeding.

15 I plan to, first, this morning, start with

16 so-called Contention 2, which is essentially a legal

17 issue. And after -- well, I don't know when lunch

18 will come. We have a motion to strike certain

19 portions of testimony, which we're going to hear a

20 little bit about. And then we'll proceed to

21 Contention 3.

22 Now, I understand one of the witnesses for

23 the Citizens Awareness Network -- I think, first, why

24 don't we have the parties for the benefit of the

25 reporter, if not others, identify themselves. Start

1 with the licensees. Mr. Silberg?

2 MR. SILBERG: Yes. My name is Jay

3 Silberg. I'm a partner with the Washington law firm

4 of Shaw Pittman. I'm here today as Counsel for Power

5 Authority of the State of New York and the Entergy

6 Companies.

7 With me at the Counsel table is Matias

8 Travieso-Diaz, a partner in the Shaw Pittman firm.

9 And on my left, Doug Levanway, a partner at the

10 Jackson, Mississippi firm of Wise, Carter. Also in

11 the room is Counsel for the Entergy Companies, Jack

12 Fulton; Counsel for the Power Authority, Gerry

13 Goldstein and William Earnstaff.

14 JUDGE BECHHOEFER: Thank you. Mr. Hom?

15 MR. HOM: My name is Steve Hom, and I'm

16 Counsel for the NRC staff, which has not been a party

17 in this proceeding. And to my left is Angela Coggins,

18 also Counsel for the staff.

19 JUDGE BECHHOEFER: CAN?

20 MR. JUDSON: My name is Timothy Judson.

21 I'm an organizer with Central New York CAN,

22 representing the CAN chapters for New York in this

23 proceeding. And with me is CAN's Executive Director,

24 Deborah Katz, and our President, Frederick Katz. And

25 we have a witness with us, Edward Smelnof.

1 JUDGE BECHHOEFER: Right. Well, the
2 witnesses will be introduced when they're put on to
3 give their testimony.
4 I understand that one of the Citizens
5 Awareness Network's witnesses, David Lochbaum will not
6 be able to be here, but that, if my latest
7 communication is correct, his testimony will be heard
8 over the telephone; is that correct?
9 MR. JUDSON: That's correct.
10 JUDGE BECHHOEFER: And have you arranged
11 whatever connections are needed so that --
12 MR. JUDSON: We've arranged that, yes.
13 JUDGE BECHHOEFER: And what time did you
14 have that --
15 MR. JUDSON: He's prepared for us to give
16 him a call on that phone on the desk at 11:30. And if
17 we're going to be running late, I told him that we
18 would let him know what time we would call him for his
19 testimony. He's available until 12:30.
20 JUDGE BECHHOEFER: Till?
21 MR. JUDSON: He's available until 12:30.
22 JUDGE BECHHOEFER: Oh, okay.
23 MR. SILBERG: Judge Bechhoefer, I'm not
24 sure that that schedule is going to work, because his
25 testimony is subject, in part, to a motion to strike,

1 and I think we need to argue that motion and decide it
2 prior to having his testimony admitted. We may be
3 able to get there by then, but it's only an hour and
4 a half.
5 JUDGE BECHHOEFER: That being so, I
6 propose maybe we should start on the oral argument on
7 the motion to strike right now, even though it doesn't
8 apply to the first -- or Contention 2, which I was
9 prepared to start with and hopefully finish this
10 morning. But why don't we listen to arguments on the
11 motion to strike. I might ask have the licensees --
12 Mr. Silberg, did you receive CAN's response to your
13 motion?
14 MR. SILBERG: Yes, we did, sir.
15 JUDGE BECHHOEFER: As did we. And
16 according to my computer back in Washington, it was
17 timely filed, although I must say I stayed up late at
18 home and tried to get into the computer. And I got
19 in, but it didn't get your -- I was in after 11:30
20 when it was theoretically filed, and I didn't pick it
21 up. So for whatever reason, I didn't get to read it
22 Sunday night.
23 MR. SILBERG: My computer showed it was
24 filed at 11:27 p.m. on Sunday, so I stayed up.
25 JUDGE BECHHOEFER: Right. I tried to get

1 after that, and it didn't show anything. So I was
2 sort of mid-afternoon.
3 Be that as it may, Mr. Silberg, you may
4 want to lead off. Of course, we've read your motion.
5 I've looked through some of the authorities on motions
6 to strike at least, and there was a couple of cases
7 that I would rely on where motions to strike, for one
8 reason or another, were not granted. These were
9 Licensing Board cases, but they were affirmed on other
10 grounds by the Appeal Board.
11 And the first one is Diablo Canyon
12 Licensing Board decision. And it's -- let's see
13 something. Yes, the decision was a fairly old one --
14 no, that's the -- yes, it was the LBP 7460. It was
15 the Licensing Board Opinion. And the cite is 8-AEC-
16 277. Their motion to strike testimony had been filed,
17 and the Licensing Board there said that the Licensing
18 Board did not agree that the testimony should be
19 stricken or that it should be given no weight at all.
20 MR. SILBERG: And there are many --
21 JUDGE BECHHOEFER: Pardon?
22 MR. SILBERG: I'm sorry. There are many
23 grounds on which motions to strike can be made or
24 denied. In this case, it's clear that you have the
25 authority to strike material which is irrelevant or

1 immaterial. That's set forth in the regulations in
2 Subpart M; it's set forth in the Commission's decision
3 explicitly.
4 The question on whether in any given case the
5 motion to strike should be granted is obviously fact-
6 specific. I don't know the specific Diablo Canyon
7 case you're referring to. But in this case the issue
8 is whether the material that we moved to strike, which
9 is identified in that attachment to our motion, is
10 within the scope of the contentions admitted by the
11 Board. CAN has admitted that you have the authority
12 to strike, and I think there's no question --
13 JUDGE BECHHOEFER: Well, I have no doubt
14 about my authority.
15 MR. SILBERG: -- from a matter of
16 authority. But the question here is whether the
17 material which we have moved to strike is indeed
18 material, immaterial within or without the scope of
19 the contentions that are admitted. Basically, the
20 contentions go to matters of nuclear safety.
21 Three issues which you have admitted with
22 respect to the third issue, financial assurance, deal
23 with three matters which are set forth specifically in
24 your February 5th order. First, whether the 85
25 percent capacity factor assumption that we used in our

1 financial analysis is appropriate or whether, as
2 recommended by CAN, we should use a lower number.
3 Second, whether the operating cost projections that we
4 have used are appropriate or, as recommended by CAN,
5 whether we should use or test for sensitivity a higher
6 cost of projections. And third, the liquidity of
7 certain Entergy subsidiaries for financial assurance
8 guarantees. And then the legal issue as to whether we
9 are required to submit projections going beyond five
10 years.
11 None of those four issues deal with
12 nuclear safety. Yes, you can make a nuclear safety
13 issue out of anything, but when you read your
14 decision, the February 5th decision, the specific
15 issues which we are here to receive testimony on, do
16 not relate in any way to matters of cost cutting,
17 matters of overtime or fatigue, matters of particular
18 technical problems that may have occurred at other
19 reactors. And it's for those reasons that we move to
20 strike.
21 Certainly, we could expand this hearing
22 into a wide variety of issues, but the purpose of the
23 Subpart M proceeding is for the Commission's decision
24 that hearings on license transfers ought to be focused
25 on the specific issues which have been admitted by the

1 presiding officer.

2 JUDGE BECHHOEFER: Well, Mr. Silberg, from

3 the response I get from CAN, they claim -- we'll just

4 take out of context for the moment Lochbaum's

5 testimony and the portions you wanted to strike --

6 they claim that bears on their -- everything that you

7 wish to strike, they claim, bears on their capacity

8 factor testimony, and that's how their expert witness

9 came to CAN's position on what an appropriate capacity

10 factor should be.

11 MR. SILBERG: No, on the contrary. Mr.

12 Lochbaum's testimony does restate figures on capacity

13 factors, and we do not quarrel -- we do not move to

14 strike those capacity factors.

15 JUDGE BECHHOEFER: Yes, I know, but --

16 MR. SILBERG: It does, however, include

17 several attachments, two being reports relating to the

18 Maine Yankee Nuclear Power Plant, which is a plant

19 owned and operated -- formerly owned and operated by

20 another company of a different design in a different

21 location, and therefore of questionable, if any,

22 relevance to this proceeding.

23 And the third had to do with a generic

24 JUDGE BECHHOEFER: Well, doesn't that go

25 to the weight?

1 MR. SILBERG: No. If something is not
2 material, it should get no weight. It should be
3 excluded completely. We should not have this record
4 cluttered up with matters which do not relate to the
5 contentions.
6 Now, in CAN's response, they argue that
7 the NRC's mission is to protect the public health and
8 safety. We all agree with that, but that's not the
9 issue here. The issue is whether the specific
10 contentions, the issues that you have admitted for
11 hearing, relate to the matters that they seek to
12 introduce.
13 They also argue that they have standing to
14 raise safety issues. We're not challenging that
15 either, but that is not the same as which issues are
16 appropriate to litigate in this case. They claim that
17 --
18 JUDGE BECHHOEFER: Well, is not safety the
19 underlying basis for all the regulations, including
20 the financial qualifications?
21 MR. SILBERG: That is absolutely correct.
22 However, if you take that expansive view, then you
23 have completely vitiated the whole purpose of
24 narrowing the hearing to specific contentions. Under
25 that theory, which you're propounding as a matter of

1 argument, I hope, any issue dealing with the safety of
2 any plant anywhere in the country would be relevant
3 for us to hear today with respect to the financial
4 assurances of the Entergy Companies to run these two
5 plants.
6 JUDGE BECHHOEFER: Well, would not that --
7 even though true, it doesn't mean that trier of fact
8 has to give much weight to those if they don't have
9 much relevance.
10 MR. SILBERG: Well, if you take that
11 approach, then the record of any hearing will be
12 infinite, because there will no be incentive to
13 exclude any matters from the hearing. I think that is
14 totally inconsistent with Commission case law, with
15 federal trial case law, with the rules of this
16 Commission.
17 The purpose of the Subpart M rules is to
18 strike immaterial evidence. If it's not material to
19 the issues that you have admitted, it ought and should
20 be stricken. Otherwise we have a record which
21 includes information of questionable, if any,
22 relevance to this proceeding. We should not expect
23 the Commission to have to wade through safety issues
24 that relate to other plants in other places of the
25 country that do not relate directly to the matters

1 that you have admitted in this case.

2 And the three issues that you have

3 admitted, in which there is fact testimony as opposed

4 to the legal issue on whether or not we need more than

5 five years projections, there is no mention in your

6 decision of anything having to do with safety. You

7 restate CAN's proposed contention at the beginning of

8 your discussion, but when you admit the issues they

9 are quite specific. And a hearing is supposed to deal

10 with the specific issues.

11 We litigated for many years before the

12 NRC, as you're well aware, to basis and specificity

13 requirements in Subpart G. The Commission has made

14 clear on any number of occasions that the issues to be

15 litigated are supposed to be well defined. Subpart M

16 proceedings are supposed to be even more specific than

17 Subpart G proceedings. If one expands, we have taken

18 away all of the benefits that the Commission sought to

19 achieve by developing the Subpart M proceedings. And

20 I think it would be a major inconsistency with what

21 the Commission had in mind when it issues Subpart M.

22 JUDGE BECHHOEFER: Well, I believe that

23 the contention does reference safety, and then it has

24 a bunch of subparts. And I think --

25 MR. SILBERG: But the parts that you have

1 admitted --

2 JUDGE BECHHOEFER: Well, not in any

3 subpart I don't reference safety, but they --

4 MR. SILBERG: Excuse me?

5 JUDGE BECHHOEFER: Each subpart does not

6 reference safety, but the whole contention does, and

7 these subparts are all part of the full contention.

8 MR. SILBERG: Well, but you did not admit

9 the entire contention. You admitted the specific

10 subparts. I think if you allow this kind of

11 testimony, you are depriving the applicant, the

12 licensee, of notice as to what the issues are that

13 they're supposed to respond to. And I think that's

14 not an appropriate way to give notice to the parties

15 from a due process standpoint, certainly, from the

16 standpoint of what we have to prepare to respond to.

17 We have no way to know what our initial testimony is

18 supposed to be.

19 And that's not the issues that you

20 admitted. You admitted capacity factors; you admitted

21 O&M costs; you admitted liquidity of financial

22 guarantees; and you admitted five-year projections.

23 You did not admit the safety of the Maine Yankee

24 Plant; you did not admit the issue of overtime; you

25 did not admit the issue of operator fatigue. Those

1 are the matters that are included in Mr. Lochbaum's
2 attachments. If we're going to get into a discussion
3 of those items, then this hearing goes far beyond
4 anything having any relevance to the license transfer
5 of these two plants.
6 JUDGE BECHHOEFER: Well, the contention
7 itself, the heading of the contention under which the
8 subparts fall, says that the license transfer
9 applications do not provide adequate financial
10 assurance for the safe operation of Fitzpatrick and
11 Indian Point 3. Because the applications do not
12 demonstrate an appropriate margin between anticipated
13 operating costs and revenue projections. And the
14 Entergy applicants do not provide evidence of access
15 to sufficient reserve funding. That's the contention
16 as a whole, and then the subparts fall into that.
17 MR. SILBERG: But you did not admit the
18 contention as a whole. You --
19 JUDGE BECHHOEFER: Well, it doesn't
20 matter. I admitted subparts, which depend for their
21 validity on the overall framework of the contention.
22 MR. SILBERG: It seems to me that this is
23 a, and properly so, a financial assurance contention.
24 It is not a contention as to an extensive examination
25 on Maine Yankee, on the culture at Maine Yankee, on

1 industry-wide standards of fatigue and overtime. And
2 admitting those exhibits puts into the record material
3 which has no bearing whatsoever on these plants.
4 JUDGE BECHHOEFER: Well, I'd like to hear
5 from CAN, but I would think --
6 MR. SILBERG: Okay. They're all --
7 JUDGE BECHHOEFER: Pardon?
8 MR. SILBERG: Yes, excuse me.
9 JUDGE BECHHOEFER: Do you have further --
10 MR. SILBERG: Well, there are also some
11 other matters which we move to strike, which are
12 beyond the scope of the contentions that are set forth
13 in our motion. It deals with a repayment of capital
14 and other financial issues which do not relate to O&M
15 costs, capacity factors or liquidity of financial
16 guarantees. Those were excluded because they simply
17 don't relate to the specific issues that you admitted.
18 JUDGE BECHHOEFER: Okay. CAN, whoever?
19 MR. JUDSON: Mr. Bechhoefer, we believe
20 that -- should I stand? Is that appropriate?
21 JUDGE BECHHOEFER: You don't have to.
22 MR. JUDSON: Okay.
23 MS. KATZ: We're used to standing in other
24 proceedings. That's why we're a little confused.
25 JUDGE BECHHOEFER: You're welcome to, but

1 --

2 MR. JUDSON: Well, Your Honor,
3 essentially, what we understand the Applicant's
4 objections to the portions of our statement and
5 testimony they wish to strike is that on the one hand
6 they believe that it's irrelevant and immaterial to
7 the proceeding, as Mr. Silberg has laid out, and that
8 the Commission has already rejected these objections
9 outright in the course of its memorandum and order.
10 We believe that in fact the Applicants are
11 wrong, in terms of -- I mean that these issues are
12 directly relevant, that they lie squarely within the
13 NRC's jurisdiction and within the NRC's power and
14 authority to address. And that, in fact, in the
15 course of the memorandum and order on our initial
16 hearing request, that the issues the Commission ruled
17 out were arguments that CAN had made at that point.
18 They were not well-documented and not
19 specific, and that they rejected them on the basis
20 that they didn't include adequate documentary support.
21 And that we hadn't demonstrated a nexus between the
22 allegations we were making towards the Entergy
23 Companies' intentions to reduce staffing and postpone
24 maintenance and the implications for safety, that we
25 hadn't demonstrated a nexus between their need to cut

1 costs and the implications for safety.

2 We don't believe that there was anything

3 in the Commission's order and specifically in the

4 passage of the Commission's order that Mr. Silberg

5 quoted in their motion to strike that specifically

6 ruled out safety as an issue in this hearing. And we

7 believe that the issue of safety and financial -- that

8 the question of safe operation is the very basis on

9 which the Commission requires financial qualifications

10 on license transfers.

11 We also believe that in this hearing,

12 under Subpart M, that we're required to demonstrate

13 that we have a traceable interest in the issues that

14 we're litigating and that CAN's interest in this

15 proceeding is the safe operation of the reactors. So

16 that we believe that on the basis of the Commission's

17 jurisdiction and the relevance and material relevance

18 of the issues we've raised to this proceeding that

19 there's no question about that.

20 We're also confounded by the fact that the

21 Applicants are raising it at this point when your

22 memorandum and order admitting the contention to this

23 proceeding, in describing the contention that was

24 admitted -- or that we submitted, directly addressed

25 the issue of adequate funding for safe operation and

1 that they could have raised this issue at that point
2 if that was their objection.
3 Now, in terms of -- what I also understand
4 Mr. Silberg as interpreting is that we're raising the
5 issues of safety in this proceeding as new contentions
6 somehow or as new issues, which would be late filed.
7 And we don't believe that that's what we're raising at
8 all. What we've submitted, in terms of our arguments
9 that there are safety implications for the Entergy
10 Companies' financial qualifications, is that there's
11 relevance to those financial qualifications in terms
12 of the NRC's jurisdiction and authority. And that it
13 actually behooves the Commission to look at financial
14 qualifications of an applicant up front and to be able
15 to determine whether it's likely that they're going to
16 be able to operate the reactor safely, that the
17 applicants actually are under an evidentiary burden to
18 be able to show that in terms of their financial
19 qualifications.
20 And that what we're arguing is that
21 they're not financially qualified, based on their
22 application, and that the outcome of that can be
23 predicted. We haven't argued that the Entergy
24 Companies are going to operate the reactors unsafely.
25 We haven't argued that their intention is to do

1 anything that would compromise safety. What we're
2 arguing is that on the basis of the financial
3 pressures that they can reasonably be expected to
4 experience as a result of the issues that have been
5 admitted for us to litigate in this proceeding, that
6 should the Entergy Companies find themselves in an
7 adverse circumstance, the safety could be compromised.
8 And we've submitted the documents on Maine
9 Yankee in order to provide documentary support to that
10 claim, that we haven't intended for there to be a
11 broad relicensing proceeding or for there to be a
12 broad generic investigation of safety within the
13 nuclear industry. What we've argued, essentially, is
14 that, based on the issues that have been admitted to
15 this proceeding, that there have been examples in the
16 industry, that the NRC actually has looked into quite
17 extensively, that show that under similar
18 circumstances safety can be compromised. And that's
19 all that we've argued.
20 Now, also in the memorandum and order that
21 you wrote granting our contention, you address similar
22 arguments that Entergy made in the process of the
23 contention stage of this proceeding where they were
24 saying -- where they were trying to characterize each
25 subissue of our contention that we raised as a

1 separate contention. And they attempted to have those
2 issues stricken as irrelevant, because they were
3 dealing with non-proprietary information as opposed to
4 the proprietary information that the Commission
5 granted us the ability to review to submit our issues.
6 What we believe is that -- excuse me a
7 second. And in the memorandum and order, you
8 addressed that issue specifically, saying that the
9 Commission hadn't ruled out everything that was not
10 proprietary at that time and that CAN was basically
11 expected to -- or the reason the Commission admitted
12 CAN to present this revised contention was in order to
13 create a complete picture of the situation of the
14 Entergy Companies' financial qualifications.
15 And that we developed our Statement of
16 Position in order to satisfy that expectation, that
17 what we wanted to do was to be able to not only
18 address the issues that we're litigating in this
19 proceeding but how the entire picture of the Entergy
20 Companies' financial qualifications is affected by
21 this. And that's the context in which we raise the
22 safety issues in this proceeding.
23 JUDGE BECHHOEFER: Right. And I notice
24 you've cited the NRC Standard Review Plan --
25 MR. JUDSON: That's right.

1 JUDGE BECHHOEFER: -- in your response.
2 And I might just want to read -- this is direction to
3 NRC staff -- but "Reviewers should review transfers
4 for the potential impact on the license, not only to
5 determine the adequacy of funds for safe operation in
6 decommissioning, but to ensure that the licensee
7 maintains adequate technical qualifications and
8 organizational control and authority over the
9 facility." That's from NUREG, N-U-R-E-G, 1577, which
10 is the Standard Review Plan on Financial
11 Qualifications.
12 I take it what you're saying is
13 essentially just that.
14 MR. JUDSON: Exactly. That's what we're
15 trying to point out. And in terms of the issue that
16 we raised in a footnote about the Entergy Companies'
17 relationship to the parent company, in terms of the
18 withdrawal of retained earnings from the reactors, we
19 proposed that as a new issue in our Statement of
20 Position, in part, because we believe that it would
21 satisfy the standards for a late filed issue. We
22 don't have the ability to address our concerns about
23 their financial qualifications except for in this
24 proceeding. And that we raised it with adequate
25 specificity.

1 And in fact, the NRC Standard Review Plan
2 also recommends to the staff that they investigate the
3 relationship that the holding company that operates
4 the reactor has to its parent companies, in terms of
5 the fate of the retained earnings that they might
6 produce. And we believe that on that basis it could
7 be admitted as a late filed issue.
8 We believe that even if it isn't admitted
9 as a late filed issue at this point, that it's
10 relevant to the record of this proceeding and that in
11 fact the Commission through -- that the NRC, through
12 the Standard Review Plan, has asked the staff to
13 address that issue. And we believe that the fact that
14 it hasn't been addressed in this proceeding yet and
15 the fact that the staff did not propose a condition on
16 the license transfer requiring that the Entergy
17 Companies notify the NRC before the parent company
18 absorbs any retained earnings, or any significant
19 retained earnings, is a newable omission in this
20 proceeding, and the Commission should be aware of it.
21 MR. SILBERG: May I respond to that, Judge
22 Bechhoefer?
23 JUDGE BECHHOEFER: Yes. You're welcome to
24 respond if you wish.
25 MR. SILBERG: First, let me point out --

1 JUDGE BECHHOEFER: Oh, let me ask, does
2 the staff have any comments on this motion to strike
3 or not?
4 MR. SILBERG: As a non-party?
5 JUDGE BECHHOEFER: You're not required to,
6 you're not a party, but I don't want to ignore you if
7 you wish to take a position.
8 MR. HOM: Okay. Well, maybe we can make
9 a few comments. I don't think there's any question
10 that the fundamental issue -- one of the fundamental
11 issues here, which is the financial qualifications
12 regulation, has a safety basis. I mean we would not
13 have a regulation on the books that was not health or
14 safety or environmentally based, so there's no
15 question about the safety nexus to the regulation.
16 But I think that the issue before us is
17 whether, in a broad sense, the Applicants have
18 satisfied the financial qualifications regulation.
19 And I believe you are able to draw the line as to
20 whether or not -- with other pieces of that that are
21 coming into play here -- but I think you can draw the
22 line as to whether that regulation has been satisfied
23 without going to the next underlying basis step and
24 inquiring into the safety aspects of the degree or not
25 that the regulation has been satisfied. To me it's

1 either it's satisfied or not through whatever methods
2 that have been presented to show the satisfaction of
3 that requirement.
4 At that point, I don't believe you then go
5 into the safety aspects, because in a sense you are
6 looking further into the regulation itself and raising
7 an issue as to whether the regulation itself and the
8 satisfaction of the regulation somehow whether that
9 adequately addresses the safety issue on which the
10 regulation is based.
11 So I believe the staff's view would be
12 that, in essence, we would support the notion that
13 introducing matters as to the safety significance
14 after you have passed the financial qualifications
15 step is irrelevant to this proceeding.
16 The wording of the contention introduces
17 a little ambiguity in the sense that it does have the
18 words "adequate financial assurance for the safe
19 operation of Fitzpatrick." Safe operation in the
20 staff's view, I believe, would be more or less a throw
21 away. I mean implicit in with adequate financial
22 assurance is safe operation of the plant. And I don't
23 believe that, at least when the staff looked at this
24 contention, we were considering that it was a two-
25 pronged contention regarding showing adequate

1 financial assurance or qualifications under the
2 regulation, plus the impact or effect that that would
3 have on safety.
4 MR. SILBERG: Let me make a couple points,
5 if I might. First, I think Mr. Judson just
6 acknowledged that at least one of the aspects that we
7 have moved to strike is a late filed contention. It's
8 not part of one of the existing contentions, but he
9 says, "We're trying to raise this as a late filed
10 contention." Unfortunately, they made no attempt to
11 meet the standards for late filed contentions that are
12 set forth in Subpart M in 2.1308. And in any showing
13 of a late filed contention, good cause is the primary
14 thing that the licensing boards look to.
15 Judge Bechhoefer, you and many other
16 licensing boards have dealt with late filed
17 contentions on a routine basis. And the kind of
18 showing that's been made here clearly would not make
19 it, if one were to apply the five standards that are
20 commonly applied for late filed contentions. There is
21 no showing of good cause other than, "Well, we were
22 too busy, we didn't get to it." So that issue
23 clearly, I think, falls beside the point.
24 Second, with respect to your citation of
25 the Standard Review Plan, again, we do not quarrel

1 whatsoever with the staff's ability, requirement to
2 look at these issues, but that's not the case here.
3 What is the case here is whether the issues that have
4 been admitted are broad enough to reach the kind of
5 testimony that CAN seeks to introduce.
6 CAN suggests that this was part of their
7 contention from the very beginning. I suggest that if
8 that were true, one might have expected to see the
9 very documents that they attached to Mr. Lochbaum's
10 testimony to support the issue. One looks in vain to
11 find them when they were moving to introduce this
12 contention. Therefore, we had no way to anticipate
13 that that in fact was what they had in mind.
14 When CAN suggests that we should have
15 objected to your order when it came out on February
16 5th, in that it admitted safety issues, the reason we
17 didn't object is that it was obvious to us that it did
18 not. When you say at the end of your February 15
19 order that you admitted Issue 3, Subparts B-1, B-2,
20 and similar issues in Subpart C and E and D, and you
21 reject Issue 3, Subpart A and E, we looked to the
22 issues that were admitted, not the broad overview,
23 because we're not litigating the broad overview issue.
24 That is what they put forward. That is not what the
25 Board accepted. The Board accepted those four

1 specific issues that I mentioned. Anything else
2 expands this proceeding well beyond its horizon.
3 If, indeed, safety issues broadly defined
4 with no specificity are allowed in at this point, we
5 could have testimony on every plant in this country,
6 on every safety issue that Mr. Lochbaum and Mr.
7 Smelnof wish to put forward, whether that testimony
8 has anything to do with these reactors, these
9 operators, these companies. It simply is not the case
10 that any safety issue is relevant to these issues
11 because NRC looks at safety. That can't be the
12 governing rule for these hearings. Otherwise these
13 hearings will become endless, and that's clearly not
14 what the Commission had in mind when it promulgated
15 Subpart M.
16 MR. JUDSON: May I respond to that?
17 JUDGE BECHHOEFER: Not at the moment.
18 You'll find you won't need to. I've decided to rule
19 on the motion and deny it. I don't believe -- I view
20 it as sort of a slicing and dicing perhaps. There are
21 elements of -- taking some of the sentences
22 individually, you could rule those out, but they all
23 go to the general proposition that the various
24 witnesses are attempting to prove. I think safety is
25 an integral part of the contention in its overview of

1 the three specific subparts. And of course the
2 specific subparts lead to the overall goal. I did not
3 admit the other subparts for one reason or another,
4 but they too would have led to the same general goal.
5 I didn't think that the subparts were specific enough,
6 the ones I didn't admit.
7 So I would -- I think the comments of the
8 Licensing Board in the case I mentioned earlier, the
9 Diablo Canyon, where it said it was the Licensing
10 Board there is reluctant to make a word by word, line
11 by line determination of which parts of a rambling
12 myriad should be stricken. And the Board therefore
13 waived the individual's testimony, giving greater
14 weight to his discussion of certain relevant matters
15 and potentially applicable and less weight to certain
16 other matters, perhaps no weight to certain other
17 matters. I think this is within the broad discretion
18 of, there the Licensing Board, here the Commission.
19 And so I think that the motion should be denied.
20 I also note the Appeal Board's comments in
21 reviewing the order, that particular order, where they
22 said, "We," being the Appeal Board here, "are not
23 aware of any principle of law or common sense which
24 would justify claiming as erroneous a few words in a
25 finding which have been completely removed from their

1 decisional and record context and are viewed in
2 isolation. This, in effect, is what one party would
3 have us do in that particular case.
4 Another case that I rely on for precedent,
5 which was another Licensing Board decision, which
6 reached essentially the same result is Florida Power
7 and Light, which is in 22-NRC-300 and where the result
8 is essentially the same. And that was affirmed,
9 although the Appeal Board, in affirming it, didn't
10 mention the motion to strike at all. That was
11 affirmed by ALAB 846, 24-NRC-409 1986.
12 In any event, I've decided to deny the
13 motion to strike. And I'm sorry you didn't get the
14 chance to have further comments, but perhaps they
15 weren't needed.
16 MR. JUDSON: That's all right.
17 MR. SILBERG: Are you ruling, Judge
18 Bechhoefer, that they have met the burdens for late
19 filed contentions and that --
20 JUDGE BECHHOEFER: No, I have not.
21 MR. SILBERG: Because one of the --
22 JUDGE BECHHOEFER: I'm not accepting late
23 filed contentions.
24 MR. SILBERG: Well, they just acknowledged
25 --

1 JUDGE BECHHOEFER: That goes to the
2 irrelevance to the particular -- or weight to be given
3 on the particular point.
4 MR. SILBERG: If something is a late filed
5 contention which is not admitted, there is not
6 relevance, because the contention isn't there. It
7 seems to me unless you're finding that they have met
8 the standards for late filed contentions, at least
9 that item that they acknowledge was a late filed
10 contention cannot be admitted.
11 JUDGE BECHHOEFER: No, I'm not admitting
12 any late filed contentions or saying they were met or
13 not met the burden. I will take the matters in terms
14 of the particular contentions or issues that have been
15 admitted. And if they're not -- don't bear much
16 relevance or not important, then we will disregard
17 them.
18 MR. SILBERG: Well, the issue -- the
19 problem I have is that since you are only certifying
20 the record to the Commission, normally the Licensing
21 Board, which hears the testimony, can determine what
22 weight it should be given. In this case, the
23 commissioners are issuing the decision. They don't
24 hear -- they're not sitting at the hearing, so unlike
25 the normal Licensing Board, they don't get to evaluate

1 the weight. So I think a decision on a motion to
2 strike is more important in this case than it is in a
3 typical situation where the Licensing Board issues the
4 decision, having heard all the testimony.
5 JUDGE BECHHOEFER: Well, that may be so,
6 but we do have a Commission representative, an
7 attorney for the Commission, who's at least listening
8 and presumably will bear some influence on the
9 Commission's thoughts on this subject. Who knows on
10 that? The Commission can read the transcript as well.
11 By the way, the whole record will be
12 certified up to the Commission. I've passed around a
13 sample of what I'm going to do. It doesn't have the
14 latest documents in it, and it does have -- it will be
15 -- there are not accession numbers listed for matters
16 that are proprietary. And there won't be, because
17 that would -- if you gave the accession number in the
18 ADAMS system, that would enable anybody to get access
19 to the document, I think. And I'm not listing
20 accession numbers for proprietary documents.
21 MR. SILBERG: Well, since no one seems to
22 be able to access documents through ADAMS, I'm not
23 sure that that's a problem.
24 (Laughter.)
25 JUDGE BECHHOEFER: Well, I put it in,

1 because the Commission, when they sent me a list of
2 documents, they sent me -- I think, all parties
3 probably got a copy of the Commission's or the
4 Secretary's memo to me. I might also say I don't
5 think CAN has conceded that or admitted that any of
6 its arguments are late filed. And to the extent they
7 bear little relevance on the contention, well, that's
8 something that the Commission -- or that I or the
9 Commission can and will take into account.
10 MR. SILBERG: Well, I heard Mr. Judson say
11 it was late filed. And he said it -- and CAN said it
12 in their written filings as well.
13 JUDGE BECHHOEFER: Well, be that as it
14 may, I'm not admitting a late-filed contention at this
15 stage.
16 MR. SILBERG: Okay.
17 JUDGE BECHHOEFER: I think at this stage
18 we will proceed with Contention 2, but we'll interrupt
19 it to hear Mr. Lochbaum at 11 o'clock, did you say?
20 MR. JUDSON: Eleven thirty.
21 JUDGE BECHHOEFER: Eleven thirty? Okay.
22 So we'll take a little break just before that time,
23 and I don't think we need a break now. We'll take a
24 break before then, and we'll interrupt with part of
25 Contention -- a portion of Contention 3, and then go

1 back to 2, to the extent we need.

2 And on 2, I think since it's a question of

3 law, I had asked CAN to lead off on this one.

4 MR. SILBERG: Mr. Bechhoefer, Judge

5 Bechhoefer, we do have testimony on Issue 2. And

6 since we have the burden, I would think normally we

7 would put our testimony into the record.

8 JUDGE BECHHOEFER: I had thought it was

9 purely -- yes, you do, as a matter of fact. I guess

10 we could shift that. The other is the normal way of

11 proceeding, but I thought that it was strictly a legal

12 issue. The person attacking the legal interpretation

13 of either the licensee or the staff or both.

14 MR. SILBERG: Well, I'm perfectly willing

15 to let them go first with the legal, but I think we

16 ought to put in the factual testimony first and then

17 --

18 JUDGE BECHHOEFER: Okay. I would have no

19 problem, but I don't want to be splitting it up too

20 much. But are you prepared right now to present your

21 factual testimony?

22 MR. SILBERG: I am.

23 JUDGE BECHHOEFER: Why don't we lead off

24 that way then.

25 MR. SILBERG: I would ask that you, Judge

1 Bechhoefer, call to the stand and swear in George W.
2 Collins and Joseph T. Henderson.
3 JUDGE BECHHOEFER: You know, I think the
4 way they were supposed to set it up, that podium was
5 supposed to be set up for witnesses, but it isn't.
6 MR. SILBERG: Well, rather than have the
7 witnesses stand, I thought it would be more typical to
8 have them sit.
9 JUDGE BECHHOEFER: Be easier to have them
10 sit, yes. I don't think the podium is set up anyway.
11 MR. SILBERG: It was, but we moved it.
12 JUDGE BECHHOEFER: So would you identify
13 yourselves again, just for --
14 MR. HENDERSON: Joe Henderson.
15 JUDGE BECHHOEFER: Henderson.
16 MR. COLLINS: And I'm George W. Collins.
17 JUDGE BECHHOEFER: Collins. Mr. Henderson
18 and Mr. Collins, do you swear that the testimony
19 you're about to give is the truth, the whole truth,
20 and nothing but the truth, so help you God?
21 MR. HENDERSON: Yes, I do.
22 MR. COLLINS: Yes, I do.
23 JUDGE BECHHOEFER: I should say, do you
24 swear or affirm? Be seated.
25 MR. SILBERG: I'd like to have them

1 authenticate the testimony, and then we can introduce
2 it into the record.
3 JUDGE BECHHOEFER: Introduce it into the
4 record, yes.
5 MR. SILBERG: Mr. Henderson, I'm showing
6 you a document entitled, "Written Direct Testimony and
7 Affidavit of Joseph T. Henderson, dated January 11,
8 2001. Was this testimony prepared by you or under
9 your direct supervision and control?
10 MR. HENDERSON: Yes.
11 MR. SILBERG: Is it true and correct, to
12 the best of your knowledge and belief?
13 MR. HENDERSON: Yes.
14 MR. SILBERG: Do you adopt it as your
15 testimony in this proceeding?
16 MR. HENDERSON: Yes.
17 MR. SILBERG: Judge Bechhoefer, I'm
18 handing this document just to identify it to the
19 reporter. I'd ask that it be incorporated in the
20 transcript at this point, as if read, as Mr.
21 Henderson's direct testimony on Issue 2.
22 JUDGE BECHHOEFER: Have you, by any chance
23 -- the Commission Subpart M seems to say that you have
24 to label each thing as an exhibit. I don't know. It
25 says it, but I don't know how important it is.

1 MR. SILBERG: We'll be happy to label it
2 as you wish.
3 JUDGE BECHHOEFER: Well, there's something
4 in the rules that says that, that exhibits -- I'll
5 turn to the section right now.
6 MR. SILBERG: It says in exhibit form. It
7 doesn't necessarily say that it has to be as an
8 exhibit.
9 JUDGE BECHHOEFER: Oh, okay.
10 MR. SILBERG: I'll be happy to label this
11 as Licensee's Exhibit 1, if --
12 JUDGE BECHHOEFER: But I would just as
13 soon have it included in the transcript, in the
14 record. That's easier for anybody reviewing it to
15 look at it. I would prefer that.
16 MR. SILBERG: Okay. Will you rule on my
17 request?
18 JUDGE BECHHOEFER: Well, any objections?
19 The testimony will be admitted into evidence in the
20 record.
21 MR. JUDSON: We don't object.
22 JUDGE BECHHOEFER: Yes. I didn't see any
23 --
24 (Whereupon, the above-referred
25 to document was marked and

1 admitted into evidence as
2 Licensee Exhibit No. 1 for
3 identification.)
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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judge:

Charles Bechhoefer,
Presiding Officer

In the Matter of POWER AUTHORITY OF THE STATE OF NEW YORK and ENTERGY NUCLEAR FITZPATRICK LLC, ENTERGY NUCLEAR INDIAN POINT 3 LLC, and ENTERGY NUCLEAR OPERATIONS, INC. (James A. FitzPatrick Nuclear Power Plant and Indian Point Nuclear Generating Unit No. 3)	Docket Nos. 50-333-LT and 50-286-LT (consolidated) ASLBP No. 01-785-02-LT

Written Direct Testimony and Affidavit of Joseph T. Henderson

STATE OF LOUISIANA)
)
PARISH OF JEFFERSON)

I, Joseph T. Henderson, being duly sworn, depose and state that the contents of the following Written Direct Testimony of Joseph T. Henderson are true, correct, accurate and complete to the best of my knowledge, information and belief:

Q: Please state your name and title.

A: My name is Joseph T. Henderson. I am Vice President and General Tax Counsel for Entergy Corporation.

Q: Please give us some information on your educational and professional background.

A: I graduated from the University of Pittsburgh with a Bachelor of Arts degree in 1979. I received my Juris Doctor from George Washington University in 1982 and received a Master of

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Laws in Taxation from Georgetown University in 1985. I also received a Master of Science in Accountancy from the University of Houston in 1989. I worked for Tax Analysts, Inc. in Arlington, Virginia, as a member of the editorial staff from 1981 to 1984. I then worked for Shell Oil Company in Houston, Texas, from 1984 to 1999 with the last position held being Associate General Tax Counsel. I came to Entergy Corporation in New Orleans, Louisiana, as Vice President and General Tax Counsel in March of 1999.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss the tax treatment of the decommissioning trust being maintained by the Power Authority of the State of New York (the "Authority") following the acquisition of the FitzPatrick Nuclear Power Station and the Indian Point 3 Nuclear Power Station by Entergy Nuclear FitzPatrick, LLC ("Entergy FitzPatrick") and Entergy Nuclear Indian Point 3, LLC ("Entergy IP3") (collectively, the "Entergy Owners").

Q: Please describe the tax treatment of the Authority's decommissioning trust following the acquisition.

A: When the Entergy Owners acquired FitzPatrick Nuclear Power Station and the Indian Point 3 Nuclear Power Station, the acquisition did not include the decommissioning trust associated with those plants. The decommissioning trust is specifically listed as an "Excluded Asset" in section 2.2(g) of the Purchase and Sale Agreement. The Authority retained any and all "rights, title, and legal and beneficial interests" in the decommissioning trust. Consequently, the Entergy Owners do not have an ownership interest in the trust and should not be taxed on the trust's earnings.

Q: What about the liability of the Authority for taxes on the earnings of the trust?

A: The Authority is a tax-exempt entity, so it should not be subject to tax on the earnings

of the trust.

Q: Under the Decommissioning Agreement, the Authority has the option under several different scenarios to transfer the trust funds to the Entergy Owners. If the trust funds are transferred, will this create a tax liability for the Entergy Owners?

A: This should not create a tax liability. The Internal Revenue Service ("IRS") has consistently taken the position that the transfer of decommissioning trusts in connection with nuclear acquisitions does not create a tax liability for the purchaser. Entergy received a private letter ruling from the IRS to this effect with regard to its acquisition of the Pilgrim Nuclear Power Station (Private Letter Ruling 199952074 (Sept. 28, 1999)). The IRS has consistently taken the same position with other nuclear acquisitions. See Private Letter Rulings 20004040 (October 29, 1999); 200034007(May 18, 2000); 200034008 (May 18,2000); 200034009 (May 18, 2000); and 200037020 (June 9, 2000).

Q: In the event that the transfer of the trust does create a tax liability, by whom would that liability be borne?

A: In the event that the transfer of the trust does create a tax liability, which is not likely under current tax law, the liability would be borne by Entergy and not by the trust. Thus, there is no danger that the trust funds would be depleted by income taxes as a result of the transfer.

Joseph T. Henderson

Joseph T. Henderson

Sworn to and Subscribed before me,
this the 11Th day of January, 2001.

Vicki D. Phillips
Notary Public

VICKI D. PHILLIPS
Notary Public, State of Texas
My Commission Expires
DECEMBER 27, 2003

1 MR. SILBERG: And I'm handing to you, Mr.
2 Collins, a document entitled, Written Direct Testimony
3 and Affidavit of George W. Collins, dated January 10,
4 2001. Was this document prepared by you or under your
5 direct supervision and control?
6 MR. COLLINS: Yes, it was.
7 MR. SILBERG: It is true and correct, to
8 the best of your knowledge and belief?
9 MR. COLLINS: Yes, it is.
10 MR. SILBERG: And do you adopt it as your
11 testimony in this proceeding?
12 MR. COLLINS: Yes, I do.
13 MR. SILBERG: Judge Bechhoefer, I'm
14 handing the document, just to identify it, to the
15 court reporter. I ask that it be included in the
16 transcript at this point, as if read, as Mr. Collins'
17 testimony on Issue 2.
18 JUDGE BECHHOEFER: So ordered. And it
19 will again be bound into the record.
20 (Whereupon, the above-referred
21 to document was marked and
22 admitted into evidence as
23 Licensee Exhibit No. 2 for
24 identification.)
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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judge:

Charles Bechhoefer,
Presiding Officer

In the Matter of POWER AUTHORITY OF THE STATE OF NEW YORK and ENTERGY NUCLEAR FITZPATRICK LLC, ENTERGY NUCLEAR INDIAN POINT 3 LLC, and ENTERGY NUCLEAR OPERATIONS, INC. (James A. FitzPatrick Nuclear Power Plant and Indian Point Nuclear Generating Unit No. 3)	Docket Nos. 50-333-LT and 50-286-LT (consolidated) ASLBP No. 01-785-02-LT

Written Direct Testimony and Affidavit of George W. Collins

State of New York)
)
County of Westchester)

I, George W. Collins, being duly sworn, depose and state that the contents of the following Written Direct Testimony and Affidavit of George W. Collins are true, correct, accurate and complete to the best of my knowledge, information and belief.

Q.1. Please state your name and business address.

A.1. My name is George W. Collins. My business address is 123 Main Street, White Plains, New York 10601.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the Power Authority of the State of New York (the "Authority") as Treasurer. My responsibilities include management of the Authority's investment portfolio, the Authority's debt, the Authority's interest rate swap program and the Risk Management Department. As part of a steering committee, I also have oversight responsibilities for hedging procedures for fossil fuels and electricity. I am also responsible for managing the Authority's nuclear plant Decommissioning Funds and overseeing the selection process for the Investment Managers for the Funds.

EXHIBIT
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Q.3. Please state your professional and educational background?

A.3. I assumed my current position in 1995, and have been with the Authority since 1986. Prior to joining the Authority, I was the Assistant Treasurer at Goldfields American Corporation and a Divisional Controller at Philips Electronics. I have a Bachelor of Administration degree from the University of Missouri.

Q.4. What is the purpose of your testimony?

A.4. The purpose of my testimony is to demonstrate that the arrangement between the Authority and Entergy Nuclear FitzPatrick LLC ("Entergy FitzPatrick") and the Authority and Entergy Nuclear IP3 ("Entergy IP3," and collectively with Entergy FitzPatrick, the "Entergy Owners") provides reasonable assurance of adequate decommissioning funding for the FitzPatrick Nuclear Plant and the Indian Point 3 Nuclear Plant, respectively.

Q.5. Describe the trust that has been established by the Authority relating to the two plants?

A.5. In 1990, the Authority established a Master Decommissioning Trust (the "Master Trust") pursuant to a Master Decommissioning Trust Agreement (the "Trust Agreement"), dated as of July 25, 1990, with the Bank of New York, as Trustee, which created two Trusts, one for each plant, with a Decommissioning Fund for each plant. The exclusive purpose of the Master Trust was to create an external source of funding to provide for the costs associated with the decommissioning of the nuclear plants, so as to comply with applicable NRC regulations.

Q.6. Do the amounts currently in the Decommissioning Funds under the Master Trust meet NRC decommissioning funding requirements?

A.6. Yes. The current amounts in the Decommissioning Funds for FitzPatrick and Indian Point 3 as of November 30, 2000 (audited) are $343 million and $314 million, respectively.

The current NRC minimum decommissioning cost estimates for the plants, as determined pursuant to NRC regulations (10 CFR Section 50.75(c)), are as follows:

FitzPatrick	Indian Point 3
$360 million	$297 million

In calculating these minimum decommissioning cost estimates, I have used the required adjustment factors for 1999, which result in a calculated decommissioning cost estimate of $360 million for FitzPatrick and $297 million for Indian Point 3, and have escalated these amounts by a 3% inflation factor for the period from January 1, 2000 to December 31, 2000. This latter adjustment was used because the adjustment factors set forth in the NRC regulations (10 CFR Section 50.75 (c)) for the year 2000 were not as yet available.

I then increased these current cost estimates by an assumed 3% inflation factor to the expiration of each of the licenses (December 12, 2015 for Indian Point 3 and October 17, 2014 for FitzPatrick) to produce the following cost estimates at license expiration:

FitzPatrick	Indian Point 3
$558 million	$476 million

To determine the minimum current decommissioning fund amounts necessary to achieve these license expiration decommissioning cost estimates, I discounted these license expiration estimates using a 5% discount factor, consisting of a 3% inflation rate and a 2% "real" return, as allowed by the NRC back to November 30, 2000. These calculations produce the following results:

Minimum Fund Amount For FitzPatrick	Minimum Fund Amount For Indian Point 3
$283 million	$229 million

As can be seen, the amounts in the Decommissioning Funds exceed these minimum fund amounts as of November 30, 2000.

Q.7. Were you involved in the negotiations between the Authority and the Entergy Owners which resulted in the Decommissioning Agreement between the Authority, Entergy FitzPatrick, and Entergy Nuclear, Inc. and the Decommissioning Agreement between the Authority, Entergy IP3 and Entergy Nuclear, Inc., both executed at the closing of sale of the nuclear plants?

A.7. Yes.

Q.8. What is the status of the Master Trust after the execution of the Decommissioning Agreements?

A.8. The Authority remains the beneficiary of the Master Trust until certain specified events occur, as described below, at which time the Authority has the option of assigning each individual Trust to the relevant Entergy Owner. However, regardless of the identity of the beneficiary, the sole purpose of the Trust is and will remain the same, namely, the provision of monies for the decommissioning of the nuclear plants.

Q.9. Describe those amendments to the Trust Agreement that were entered into at the closing of the sale of the nuclear plants whose terms have increased NRC oversight of the Master Trust?

A.9. The Trust Agreement has been amended to require the following:

First, no disbursements or payments from the Master Trust, other than for ordinary administrative expenses, shall be made by the Trustee until the Trustee has first given the NRC 30 days' notice of the payment. No disbursements or payments from the Master Trust shall be made if the Trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation of the NRC.

Second, the Trust Agreement may not be modified in any material respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation of the NRC.

Third, the provisions or purpose of the Trust Agreement may be enforced by the NRC against the Authority and the Trustee with respect to the disbursement of the Master Trust funds to the extent necessary to ensure compliance with or satisfaction of the NRC's decommissioning requirements.

By these modifications, the NRC has substantially increased its oversight and control over the Master Trust.

Q.10. In the Orders approving the license transfers, were there additional provisions that supplemented the NRC's oversight over the Master Trust?

A.10. The Orders required that the Authority shall waive any right to deny, contest or challenge the NRC's jurisdiction over the Authority with respect to the nuclear plants to the extent that there may arise in the future any matter warranting action by the NRC to ensure compliance with the NRC's decommissioning requirements regarding the disposition and use of amounts in the Decommissioning Funds until the earlier of the transfer of such Funds to the Entergy Owners or the completion of the decommissioning of the plants.

Q.11. Describe the decommissioning arrangement established by the Decommissioning Agreements?

A.11. Each of the Entergy Owners entered into a Decommissioning Agreement with the Authority and Entergy Nuclear, Inc., relating to responsibility for decommissioning the nuclear plant acquired by it. Under the Decommissioning Agreements, the Authority will remain the beneficiary of each of the Decommissioning Funds established for the two plants under the Trust Agreement until certain events occur, as discussed below.

Under each plant's Decommissioning Agreement, the Authority has contractual decommissioning responsibility with respect to the plant until license expiration, a change in the tax status of the plant's Decommissioning Fund, or any early dismantlement of the plant, at which time the Authority will have the option to terminate its decommissioning responsibility. The Authority's decommissioning responsibility is limited to the lesser of the Inflation Adjusted Cost Amount (described below) or the amount in the plant's Decommissioning Fund.

If the Authority terminates its decommissioning responsibility, it must transfer the plant's Decommissioning Fund to the Entergy Owner owning the plant, except that monies in the Decommissioning Fund in excess of the Inflation Adjusted Cost Amount, described below, would be paid to the Authority or, if such release of excess Decommissioning Fund monies is not possible, alternative payment arrangements, not involving Decommissioning Fund monies, between the Authority and the Entergy Owner set forth in the Decommissioning Agreement would go into effect.

Q.12. Explain what is meant by the Inflation Adjusted Cost Amount?

A.12. The Inflation Adjusted Cost Amount for a plant means a fixed estimated decommissioning cost amount set forth in the plant's Decommissioning Agreement which was determined as a result of negotiations between the parties, adjusted up or down in accordance with the effect of increases and decreases in the NRC minimum

decommissioning cost estimate amounts applicable to the plant. If the FitzPatrick or Indian Point 3 Entergy Owner purchases or operates, with the right to decommission, another plant at the FitzPatrick or Indian Point 3 site, as the case may be, then the Inflation Adjusted Cost Amount would decrease by $25 million or $50 million in the case of the FitzPatrick site (depending upon whether one or two of the adjoining Nine Mile Point plants are purchased or operated) and by $50 million in the case of the Indian Point 3 site.

Q.13. What do the Decommissioning Agreements provide if the Authority is required to decommission a plant pursuant to the relevant Agreement?

A.13. If the Authority is required to decommission FitzPatrick or Indian Point 3 pursuant to the relevant Decommissioning Agreement, Entergy Nuclear, Inc. would be obligated to enter into a fixed price contract with the Authority to decommission the plant, the price being equal to the lesser of the Inflation Adjusted Cost Amount or the plant's Decommissioning Fund amount.

Q.14. Will the Authority be obligated to make any more contributions to the Master Trust?

A.14. Under the Decommissioning Agreements, the Authority will not be obligated to make any further contributions to the Decommissioning Funds. If, in the future, NRC requirements call for additional monies to be deposited, the Entergy Owners would be obligated to make such additional contributions to additional decommissioning funds to be created by the Entergy Owners to meet such requirements.

Q.15. The suggestion has been made that the Authority and the Entergy Owners' decommissioning approach has resulted in limitations on the availability of funds which may prevent the Entergy Owners from meeting minimum regulatory requirements. Could you comment on this assertion?

A.15. As noted above, the Decommissioning Funds currently meet NRC funding requirements.

As to the issue of the availability of these funds, I will assume that the assertion relates to the situation where the Authority is the beneficiary of the Decommissioning Funds. In this situation, the Authority has a contractual responsibility to decommission the plants, to the extent of the amounts in the Funds, and would use the Decommissioning Funds to perform the decommissioning.

Although the Decommissioning Agreements allow for a release of monies to the Authority from the Funds representing the excess of monies in the Funds above the Inflation Adjusted Amount, it must be emphasized that the NRC has maintained jurisdiction over the Authority for the purpose of utilizing the monies in the Decommissioning Funds for decommissioning purposes. Moreover, as I stated above, prior notice must be given to the NRC before any disbursements or payments from the Master Trust can be made and no release of funds will be made if prior written objection is receive from the NRC..

In addition to the other safeguards discussed above, these conditions serve to ensure that there will be adequate monies in the Decommissioning Funds and that these monies in the Decommissioning Funds will be used for decommissioning.

Q.16. Is it your view that the decommissioning arrangement created by the Decommissioning Agreements provides reasonable assurance of decommissioning consistent with applicable NRC requirements?

A.16. Yes. As noted above, the Master Trust is funded in amounts meeting NRC funding requirements and may be used only for decommissioning purposes, with the amendments to the Trust Agreement and the provisions of the license transfer orders providing enhanced NRC oversight over the disposition of the Trust monies.

To the extent the Authority retains the Master Trust, it is contractually obligated to decommission the units, and would use the Trust funds to do so. Further, if the Authority is required to decommission the plants, Entergy Nuclear Inc. would be obligated to carry out the decommissioning of each plant at the price specified in the applicable Decommissioning Agreement, which would not exceed the amount in the relevant Decommissioning Fund. Although the Authority's responsibility to decommission each plant would not exceed the amount in the applicable Decommissioning Fund, the Entergy Owner would still have overall responsibility to decommission.

Consequently, even when the Authority retains the Master Trust, the situation is comparable to that which would be present if the Entergy Owner were the beneficiary of the Trust, in that in both cases the funds in the Master Trust will be available for the decommissioning of the plants.

Q.17. What is the tax status of the Authority?

A.17. The Authority is exempt from Federal and State income taxation, including income generated by the Decommissioning Funds while the Authority is the beneficiary of the Master Trust.

Q.18. Does this complete your testimony?

A.18. Yes, it does.

George W Collins
George W. Collins

Subscribed and Sworn
to before me this 10th
day of January, 2001.
Eileen P. Flynn
Notary Public

EILEEN P. FLYNN
Notary Public, State of New York
No. 02FL6016923
Qualified in Queens County
Commission Expires November 30, 2002

1 MR. SILBERG: And these two witnesses are
2 available for your questions.
3 JUDGE BECHHOEFER: Well, at the moment, I
4 have a question for CAN, generally. Are you
5 challenging the expertise or qualifications of Mr.
6 Collins or Mr. Henderson, either one?
7 MR. JUDSON: Your Honor, we're not
8 questioning their expertise or qualifications. To
9 clarify, perhaps, what we said in our response to
10 their testimony, it's that what the -- we believe that
11 what the Commission admitted was a legal question
12 about whether the arrangement that the Entergy
13 Companies and NYPA are proposing in terms of
14 decommissioning and handling the decommissioning is
15 legal under the regulations.
16 And that the witnesses that the Entergy
17 Companies and NYPA have presented are testifying to
18 whether the decommissioning fund is properly
19 constituted and satisfies the NRC's requirements for
20 minimum decommissioning funding. And that the
21 Commission actually specifically ruled out that issue
22 in the course of the memorandum and order because of
23 the fact that it's not contestable, that the fund is
24 actually properly constituted at this point.
25 We don't believe that their testimony

1 should be stricken essentially because they also
2 explain other issues related to the tax status of the
3 decommissioning fund, the potential consequences of
4 that, and Entergy and NYPA's commitments and
5 obligations under the decommissioning agreements. And
6 so believe that that record is actually helpful in
7 terms of understanding the matters presented in the
8 application.
9 JUDGE BECHHOEFER: I have a question
10 that's sort of derived from staff's safety evaluation.
11 And my first one is that where it states that the
12 decommissioning funding assurance for both facilities,
13 it says, continue to be held for the benefit of NYPA
14 until Fitzpatrick is decommissioned. My question is
15 what about Indian Point?
16 MR. SILBERG: I believe you're probably
17 looking at the staff safety evaluation for
18 Fitzpatrick.
19 JUDGE BECHHOEFER: I am, I am.
20 MR. SILBERG: But if you look at the one
21 for Indian Point, it will say the same thing except
22 Indian Point.
23 MR. JUDSON: The applications were
24 evaluated separately.
25 JUDGE BECHHOEFER: Pardon?

1 MR. JUDSON: The applications were each
2 evaluated separately by the staff.
3 JUDGE BECHHOEFER: Oh, okay. I have a
4 question for the staff, but I'll hold that till later.
5 I have a question of whether -- and I'm
6 not sure these witnesses are the proper or not, but I
7 think the probably are. The New York Power Authority
8 continues to hold the trust fund even though
9 regulatory responsibility for decommissioning will
10 reside with Entergy. And it says that the NYPA
11 interest in the trust may be transferred only to the
12 licensed owner of Fitzpatrick responsible for
13 decommissioning and is not subject to the claims of
14 NYPA creditors. Now, although protected by contract,
15 is this a valid position under New York law, do you
16 know?
17 MR. SILBERG: Who are you asking?
18 JUDGE BECHHOEFER: I'm not sure which
19 witness, but either of the witnesses.
20 MR. SILBERG: Mr. Henderson's testimony is
21 primarily on the tax issues, and Mr. Collins' --
22 JUDGE BECHHOEFER: No, I know. It's not
23 really a tax question. Would the trust party subject
24 to the claims of other creditors?
25 MR. HENDERSON: I can't speak to that

1 issue.

2 MR. SILBERG: Mr. Collins?

3 JUDGE BECHHOEFER: Well, either one. If

4 either of you know.

5 MR. COLLINS: Judge, these funds were set

6 up with an external trustee outside the control or the

7 authority of the NYPA. So I don't believe that these

8 can become subject to creditors of NYPA under current

9 law. But that's something you would have to ask

10 NYPA's staff specifically about.

11 MR. SILBERG: Is the question whether the

12 trust funds are subject to claims of creditors?

13 JUDGE BECHHOEFER: Yes.

14 MR. SILBERG: Okay. The answer to that,

15 and the trust funds themselves, which are in the

16 record --

17 JUDGE BECHHOEFER: Yes, they are.

18 MR. SILBERG: -- the answer to that is no.

19 There's a specific provision in that. Furthermore,

20 under the --

21 JUDGE BECHHOEFER: Well, but is that kind

22 of provision valid under New York law, I guess it

23 would be? If NYPA should go bankrupt, for instance,

24 and had to transfer the funds, would they be subject

25 to other creditors?

1 MR. SILBERG: Well, under the conditions
2 that are established, no money can be transferred from
3 the funds without prior notice to the NRC and cannot
4 be transferred with NRC objections. So, presumably,
5 NRC would not allow transfer of these funds to
6 creditors not involved in decommissioning, wholly
7 apart from the question of New York law, which we
8 could certainly write a legal opinion on that. I
9 can't give you an off-the-top-of-the-head reaction.
10 Maybe some of our New York lawyers can.
11 As Mr. Goldstein noted, just wanted to
12 make sure that you're aware, as we are, that the funds
13 are not held by NYPA, but rather they're held by the
14 trustee, the Bank of New York.
15 JUDGE BECHHOEFER: Well, I know that.
16 MR. SILBERG: And we could get a statement
17 from the Bank of New York, but the funds cannot be
18 transferred with NRC objection.
19 JUDGE BECHHOEFER: Well, I've been
20 involved in another case having nothing to do with
21 this where the trustee in bankruptcy for a defunct
22 company. The company used to be called the Atlas
23 Corporation, and it's now called the Mohed Mill
24 Rehabilitation Trust, I think it is. And there was a
25 definite lack of funds, and Congress eventually had to

1 step in.

2 MR. SILBERG: Now, in that case, Judge

3 Bechhoefer --

4 JUDGE BECHHOEFER: I know the differences.

5 MR. SILBERG: -- we represent those

6 companies. Those funds were made available for the

7 decommissioning of that site. There were additional

8 funds provided by Congress, but that's wholly apart

9 from the question of whether the decommissioning trust

10 funds were made available. They were.

11 JUDGE BECHHOEFER: Well, be that as it

12 may, that's still an ongoing proceeding, although it's

13 not going to be very -- it's going to be transferred

14 away.

15 Now, there is a statement that NYPA

16 retains the contractual obligation to decommission.

17 But the amounts are very definitely limited. And my

18 first question is if the costs are greater, who pays?

19 MR. COLLINS: I think our agreement,

20 Judge, with Entergy very clearly spells that out, that

21 the costs of decommissioning that exceed the amount of

22 money that are in the fund or the inflation cost

23 adjusted amount, that Entergy pays the difference. It

24 is their responsibility, because they will enter into

25 a fixed price contract with us to decommissions these

1 plants at a fixed price.

2 JUDGE BECHHOEFER: I see. So Entergy will

3 --

4 MR. COLLINS: Yes, they will.

5 JUDGE BECHHOEFER: -- pay. So these funds

6 will -- they may well be adequate, but they might not

7 be also.

8 MR. SILBERG: I would not, Judge

9 Bechhoefer, that since the funds exceed the NRC

10 minimums, which is conceded to all parties, that that

11 question, while it's interesting from an academic

12 standpoint, is not relevant from the standpoint of

13 this license transfer proceeding.

14 JUDGE BECHHOEFER: I'm not sure that any

15 reactor is ever meeting just the minimum standards.

16 I'm not sure that any decommissioning has had

17 sufficient funding based purely on that, but I'm not

18 sure one way or the other.

19 MR. SILBERG: Well, that's an issue that's

20 been dealt with by the Commission in setting the

21 standards in 10 CFR 50.75.

22 JUDGE BECHHOEFER: I know it, I know it.

23 Okay. But let me give you another example. If the

24 costs turn out to be more, for instance -- following

25 what's known as an LTP hearing, which the Commission

1 has been offering lately -- License Termination Plan
2 that is, and that's a subpart -- at the moment is a
3 Subpart G type hearing, because I've participated in
4 at least one -- what if the Licensing Board there
5 should determine that activities in addition to those
6 set forth in the proposed LTP by the licensee are
7 necessary, such as surveys done using the methodology
8 different from that proposed by the licensee? Would
9 funds of that sort be covered, funds to pay that type
10 of expense, assuming the Licensing Board found those
11 necessary and the Commission approved or the
12 Commission didn't disturb the ruling?
13 MR. SILBERG: Is the question, who would
14 be responsible for paying those funds?
15 JUDGE BECHHOEFER: Yes, yes. And would
16 that be Entergy?
17 MR. COLLINS: Judge, again, it falls to
18 the same exact criteria. If the funds are -- if
19 monies are available in the fund to pay for these and
20 these are considered decommissioning costs by the NRC,
21 then they would pay out of the fund. If they're not
22 available, it would fall to Entergy to provide those
23 funds to make sure that the site was placed which
24 satisfied the NRC requirements.
25 JUDGE BECHHOEFER: Now, again, we may not

1 need the witnesses themselves for this question, but
2 I'd like to know whether the parties, all three of
3 them, really, or all two of them plus the staff,
4 believe that the conditions outlined on pages 8 and 9
5 of the SER are adequate? And I don't know if we
6 should wait till these witnesses are through on that
7 one.
8 MR. SILBERG: Well, we believe that
9 they're more than adequate.
10 JUDGE BECHHOEFER: Well, I'd like to find
11 out if there are any specific objections, but we could
12 perhaps --
13 MR. SILBERG: We have not objections to
14 those conditions.
15 JUDGE BECHHOEFER: Right. Well, does CAN
16 -- are you aware of the conditions I'm talking about?
17 MS. KATZ: Yes. We are concerned about
18 some of these conditions, in terms of NYPA's
19 responsibility in the long run for contamination that
20 may be off-site, that Entergy is not taking
21 responsibility for and has made an agreement not to
22 take responsibility for, that there is no mechanism to
23 control NYPA's paying or analyzing or being
24 accountable for any contamination.
25 I mean one of the things that's been found

1 in License Termination Plan hearings is that there's
2 been a lot more contamination than had been expected,
3 and that there's been off-site contamination at times.
4 And our concern is that there is no way to hold NYPA
5 accountable for what waste may eventually be found or
6 even a way to, at this point, analyze for what may be
7 there and set up a funding mechanism to make it
8 possible for NYPA to be accountable for it.
9 MR. JUDSON: We're also concerned, in
10 terms of the conditions that have already been
11 proposed, that while the staff has attempted to
12 address some of the problems in the arrangement in
13 this way, that this is really -- this really puts the
14 NRC in a reactive position, so that in a position of
15 having to take action against NYPA once NYPA has
16 already mishandled the funds in a certain way. That's
17 sort of what they contemplate, is that there could be
18 a potential mishandling of the funds under these
19 circumstances.
20 And that while the staff attempts to
21 predict those circumstances and to address them
22 through these conditions, that in fact it leaves the
23 NRC in a position of having to react to those as
24 opposed to be able to take a proactive regulatory
25 stance, which is what would usually be contemplated in

1 terms of the actual licensee who's performing
2 decommissioning and responsible for it actually
3 possessing their own funds.
4 MS. KATZ: And, in fact, it creates a
5 really anomalous situation, which at a certain point
6 if there is a mismanagement of funds, the license is
7 returned to NYPA. But then it's not clear who's going
8 to operate the reactor at that point. What happens to
9 Entergy then? And it's also not clear who's going to
10 fully clean the site up and who will be accountable
11 for what if the license is then, at that point,
12 returned to NYPA. Is Entergy then not responsible for
13 what contamination is made? It creates a terribly
14 complex situation that we feel is unnecessary.
15 JUDGE BECHHOEFER: This is not a question
16 of operating the reactor in particular.
17 MS. KATZ: No.
18 JUDGE BECHHOEFER: This is a
19 decommissioning issue.
20 MS. KATZ: It's not in terms of operation,
21 but what in fact they talk about, if there's a
22 mismanagement of funds, is that the license can be
23 returned to NYPA. And that has the potential to set
24 up a lot of confusion about who is then responsible
25 for what in terms of whether it's operating or

1 decommissioning or managing the funds.

2 MR. JUDSON: Your Honor, the staff in

3 their statement regarding this issue talked about this

4 question. And what they said was that in the

5 circumstance that the NRC has to enforce these

6 conditions against a company that isn't a licensee,

7 that in fact the NRC could -- that in the case that

8 NYPA violates the conditions of this license transfer,

9 which they have proposed, that the NRC could reinstate

10 NYPA as the licensee.

11 And we believe that, on the one hand, I

12 mean this is a completely anomalous situation in which

13 it's, just as Deb referred to, it's not clear about

14 what happened to the reactors if they were operating

15 at the time that the staff had to take that action.

16 And we believe that there's actually a question of

17 whether the NRC would really be willing to do that.

18 And in the case that the NRC was unwilling

19 to create a situation to destabilize two operating

20 reactors, that this potentially leaves the NRC in sort

21 of a toothless regulatory stance, and that that is

22 really dangerous.

23 MR. SILBERG: Judge Bechhoefer, could I

24 respond to some of the points or are you going to hear

25 from the staff first? Because there are some

1 statements in there that --

2 JUDGE BECHHOEFER: I'd like to hear from

3 the staff.

4 MR. SILBERG: -- need to be responded to.

5 MR. HOM: Would you like that at this

6 time, Judge?

7 JUDGE BECHHOEFER: I guess until we are

8 through with the two witnesses, maybe we'll wait, but

9 I do want to hear the staff position on this.

10 MR. SILBERG: Judge Bechhoefer, can I

11 respond to some of those points of CAN's statement?

12 JUDGE BECHHOEFER: Yes.

13 MR. SILBERG: First, they talked about if

14 there's a mismanagement of funds by NYPA. NYPA does

15 not have the funds. The funds are held by the Bank of

16 New York, a trustee. So I simply don't know what

17 they're talking about of NYPA mismanaging the funds.

18 With respect to the concerns about off-

19 site contamination, that's an issue which they briefed

20 in their papers referring to Schedule 5.13, the

21 Purchase and Sale Agreement. As we pointed out in our

22 response, Section 5.13 of the Purchase and Sale

23 Agreement deals with non-radiological contamination --

24 not off-site, by the way -- non-radiological

25 contamination, which is retained by NYPA. Since it's

1 an non-radiological contamination, it has nothing to
2 do with this proceeding. So their speculation about
3 contamination off-site has no basis whatsoever.
4 The documents that they cited in their
5 pleadings, which we responded to, talked about
6 releases off-site within regulatory limits and
7 therefore not subject to remediation, not
8 contamination whatsoever. So what we're hearing are
9 speculations about things that don't exist or that are
10 outside the scope of NRC's regulatory requirements and
11 speculations as to mismanagement of funds that have no
12 basis either.
13 JUDGE BECHHOEFER: Mr. Silberg, if
14 something should have to be -- if some decommissioning
15 activity has to be accomplished -- NRC may be even
16 necessary -- is NYPA or PASNY, or whatever they're
17 called, out of the picture completely?
18 MR. SILBERG: Vis-a-vis the NRC, the
19 situation is as follows: The licensee of the plants
20 obviously are the Entergy Companies. They are subject
21 to NRC's regulatory jurisdiction and oversight with
22 respect to decommissioning obligations as well as all
23 other obligations. The Commission, in approving this
24 transfer, has imposed a number of conditions and
25 asserted a number of statements of jurisdiction, which

1 the Power Authority has consented to, which gives the
2 NRC the right to take certain actions against NYPA
3 even though it is not a licensee. So the NRC has
4 asserted jurisdiction, and we have agreed not to
5 contest that jurisdiction over NYPA with respect to
6 some issues.
7 NRC has full regulatory jurisdiction over
8 Entergy's activities. The relationship between NYPA
9 and Entergy is one of contract, and that can be
10 enforced by the parties as appropriate. And the NRC,
11 I believe, has said that they may have third party
12 authority in footnote 13 of their brief. So there is
13 ample authority on the NRC's part to take action
14 against whoever is needed.
15 And, of course, as I've said, the money in
16 the decommissioning fund can only be released if the
17 NRC approves it, because we have to give pre-notice,
18 30 days pre-notice, to the NRC that any monies from
19 the fund are going to be released. And the trustee
20 cannot release those funds if the NRC objects. So
21 there are at least three different levels of
22 protection for the fund.
23 JUDGE BECHHOEFER: Is NYPA completely out
24 of the picture? Would the NRC direct NYPA or direct
25 the trustee --

1 MR. SILBERG: The NRC --

2 JUDGE BECHHOEFER: -- for funds to be

3 expended?

4 MR. SILBERG: The NRC has the authority to

5 direct that no funds be expended if the NRC objects to

6 the proposal. Obviously, to go through

7 decommissioning, one has to go through an NRC

8 licensing proceeding, which you described. Five years

9 beforehand one has to provide much more detail on how

10 one would decommission.

11 JUDGE BECHHOEFER: It's now on the LTP

12 hearing.

13 MR. SILBERG: Right. And that whole

14 process is beginning to be well accepted and well

15 understood. There will be a well-defined

16 decommissioning process that is established long

17 before the end of licensed operation of the plant.

18 And through that process, how decommissioning will

19 take place will be determined and approved by the NRC

20 with appropriate input from the public.

21 JUDGE BECHHOEFER: Well, would the NRC

22 have its directions go to NYPA or PASNY or to the

23 trustee?

24 MR. SILBERG: The NRC can issue directions

25 to both.

1 JUDGE BECHHOEFER: I see. That, you --

2 MR. SILBERG: The normal licensing

3 relationship will be with Entergy. However, NRC has

4 asserted special and unique relationship with NYPA

5 that will continue, that is continuing, that gives the

6 NRC the right to direct NYPA to do certain things and

7 take certain actions. So the NRC will have a choice

8 of options down the road if that's necessary.

9 JUDGE BECHHOEFER: But who would direct

10 the trustee to either spend or not spend?

11 MR. SILBERG: I believe that is done

12 through NYPA until the funds are transferred.

13 MR. COLLINS: NYPA would give directions

14 to the trustee to expend for decommissioning expenses

15 based on the approval of the NRC.

16 JUDGE BECHHOEFER: I see. So once the

17 funds are in trust, they still can be controlled by

18 NYPA or --

19 MR. COLLINS: Or we can administer the

20 expenditures of them, yes.

21 JUDGE BECHHOEFER: Right.

22 MR. COLLINS: I mean that's our basic

23 function, is to administer these funds.

24 JUDGE BECHHOEFER: At page 13 of CAN's

25 February 1st response, CAN points out a possible

1 conflict of interest in NYPA retaining control of the
2 decommissioning fund since NYPA will be able to retain
3 the difference between the amount of the fund and the
4 amount Entergy needs to decommission the facilities to
5 NRC standards. By retaining control of the
6 decommissioning fund, NYPA therefore could elect to
7 allow Entergy to spend as little on decommissioning as
8 possible and save money for itself. Is that --
9 MR. COLLINS: We don't believe that
10 creates a conflict of interest, Judge, for three
11 reasons. First, the NRC must approve the
12 decommissioning plan. Second of all, they approve all
13 expenditures that come out of the plan, and our
14 agreement with Entergy is that the site will be
15 restored in such a state that it can be released for
16 unrestricted use.
17 JUDGE BECHHOEFER: Unrestricted or --
18 MR. COLLINS: Unrestricted. That's our
19 agreement with Entergy.
20 JUDGE BECHHOEFER: So that's greenfield.
21 I had read the Commission's decision as saying, "Well,
22 they're not required to go to greenfield standards."
23 MR. COLLINS: And I think that Entergy --
24 JUDGE BECHHOEFER: And under current
25 rules, they wouldn't be.

1 MR. COLLINS: That's correct. But our
2 agreement with Entergy is that it will be restored to
3 an unrestricted use, so that it can be released for
4 unrestricted use.
5 The other thing is, is Entergy, as a
6 licensee, is going to perform the decommissioning
7 according to the NRC standards. And I think they will
8 assure that that's done no matter how much it costs.
9 The other thing I think that you should be
10 aware of, that is in there to make sure that there's
11 no windfall to Entergy so that they can in fact
12 decommission this plant for much less and take all of
13 the monies that would be in the fund. Any excess
14 amounts like that would revert back to NYPA and would
15 be used for the benefit of our ratepayers. We didn't
16 want Entergy to make money off of decommissioning of
17 the fund.
18 JUDGE BECHHOEFER: Well, does NYPA have
19 ratepayers, will they have?
20 MR. COLLINS: We'll have ratepayers for at
21 least 2013 and probably beyond, we get a 50-year
22 license extension on a Niagra project. We'll have
23 ratepayers for years and years to come.
24 JUDGE BECHHOEFER: I think that, at this
25 stage, given the fact that it's almost 11:30, we

1 should take a break. I think we've covered all the
2 questions we have for the witnesses, not necessarily
3 the questions we have for the parties on Contention 2
4 -- or Issue 2, but I think since it's getting to be
5 11:25 at least, we should probably take a short break
6 and then come back to hear Mr. Lochbaum.
7 And I don't know whether we'll need to
8 recall either of the witnesses or not. Based on my
9 current questions and others that I've been given, I
10 don't think we'll have any further direct questions,
11 but we're not sure. And the witnesses, you may want
12 to have them available to call on to answer some
13 aspects of --
14 MR. SILBERG: They will be here.
15 JUDGE BECHHOEFER: Okay. So let's adjourn
16 -- well, not adjourn, but take a short recess, come
17 back in ten minutes, and then we'll -- hopefully our
18 audio system will work.
19 (Whereupon, the foregoing matter went off
20 the record at 11:23 a.m. and went back on
21 the record at 11:40 a.m.)
22 MR. SILBERG: We can see if this is being
23 picked up by the speakers.
24 MR. LOCHBAUM: Okay. This is David
25 Lochbaum, engineer for the Union of Concerned

1 Scientists.

2 MR. SILBERG: That's more than we wanted

3 to hear from.

4 JUDGE BECHHOEFER: At this stage, I'll ask

5 you some questions.

6 MR. FRYE: Can we reconvene the hearing

7 now?

8 JUDGE BECHHOEFER: Okay. We're back on

9 the record. We are going to hear the testimony of

10 David Lochbaum. This testimony relates to a portion

11 of Contention 3, which we haven't quite gotten to yet.

12 I might add that Contention 3 involves a considerably

13 amount of proprietary data, but I don't believe any is

14 involved in Mr. Lochbaum's testimony. But parties

15 should be alert to, and the licensee particularly

16 should be alert to when proprietary data is discussed,

17 if it should be discussed, to alert me to that fact.

18 I don't imagine that there will be any involved with

19 Mr. Lochbaum's testimony, which is not submitted under

20 proprietary protection.

21 MR. SILBERG: Yes. His testimony, as

22 submitted, to my knowledge, did not involve any

23 proprietary information. However, I would ask that

24 Mr. Lochbaum, to the extent he's asked any questions

25 at least, refrain from discussing any information that

1 was presented in our proprietary testimony or in the
2 proprietary portions of the application or in that
3 portion of CAN's testimony which contains proprietary
4 information.
5 MR. JUDSON: Your Honor? Your Honor, to
6 clarify the record, Mr. Lochbaum never signed a
7 confidentiality agreement with the Entergy Companies
8 or NYPA and has not reviewed any of the unredacted
9 documents or their testimony or Statement of Position
10 because of the proprietary nature of the information
11 involved. He's speaking to issues that we asked him
12 to address in terms of the projected capacity factors
13 for the reactors and the ability of the Entergy
14 Companies to rely on those for their financial
15 qualifications.
16 JUDGE BECHHOEFER: Mr. Judson, do you wish
17 now to present, for the record, Mr. Lochbaum's
18 testimony?
19 MR. JUDSON: We would like to submit Mr.
20 Lochbaum's testimony as part of the record. We've
21 submitted it in terms of the filing schedules. I'm
22 not sure if we need to present it to the reporter.
23 JUDGE BECHHOEFER: Well, normally you'd
24 present a copy to the reporter, and it gets bound into
25 the record as if read.

1 MR. JUDSON: Okay.

2 JUDGE BECHHOEFER: It becomes part of the

3 record.

4 MR. JUDSON: We would like to do that,

5 yes. What I have here are the testimony of Mr.

6 Lochbaum and his supporting exhibits, including his

7 resume, the NRC report on Main Yankee, and another

8 report from Main Yankee, the Cultural Assessment Team

9 report, which is Exhibit C to his testimony, and a

10 document Mr. Lochbaum produced for the Union of

11 Concerned Scientists on overtime and staffing problems

12 in the commercial nuclear power industry.

13 Should we have Mr. Lochbaum swear that

14 these are --

15 JUDGE BECHHOEFER: Well, that --

16 MR. JUDSON: Okay.

17 JUDGE BECHHOEFER: Mr. Lochbaum?

18 MR. LOCHBAUM: Yes.

19 JUDGE BECHHOEFER: Did you hear Mr.

20 Judson's description of your testimony and that

21 attachments?

22 MR. LOCHBAUM: Yes, I did.

23 JUDGE BECHHOEFER: First, as a witness, do

24 you swear or affirm that your testimony is the truth,

25 the whole truth, and nothing but the truth?

1 MR. LOCHBAUM: I do so swear.

2 JUDGE BECHHOEFER: Mr. Judson will now
3 present to the reporter -- Mr. Lochbaum, in case you
4 didn't hear, we denied the motion to strike portions
5 of your testimony, as well as portions of CAN's
6 Statement of Position and portions of Mr. Smelnof's
7 testimony. You may not have known that, but we ruled
8 earlier this morning to that effect. Would you
9 present the -- Judge will present the testimony and
10 exhibits, as identified. Mr. Lochbaum, these
11 testimony plus exhibits, are they true and correct, to
12 your knowledge?

13 MR. LOCHBAUM: Yes, they are.

14 JUDGE BECHHOEFER: And are there any
15 corrections, typographical or otherwise, of that sort
16 that should be made before we introduce them into the
17 record?

18 MR. LOCHBAUM: Not that I'm aware of, no.

19 JUDGE BECHHOEFER: Okay. Mr. Lochbaum's
20 testimony will be introduced into the record and bound
21 into the record, as if read.

22 (Whereupon, the above-referred
23 to document was marked and
24 admitted into evidence as CAN
25 Exhibit No. 1.)

Testimony of David A. Lochbaum
Nuclear Safety Engineer,
Union of Concerned Scientists

EXHIBIT
CAN
1

Supporting Exhibits to Mr. Lochbaum's Testimony

A) Resume of Mr. Lochbaum

B) U. S. Nuclear Regulatory Commission. Independent Safety Assessment of Maine Yankee Atomic Power Company. October 7, 1996.

C) Maine Yankee Atomic Power Company Cultural Assessment Team. Cultural Assessment Team Report on Factors Affecting the Reporting of Issues and Concerns at Maine Yankee. May 14, 1996.

D) Union of Concerned Scientists. Overtime and Staffing Problems in the Commercial Nuclear Power Industry. March 1999.

LBP-01-04

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISISON

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judge:

Charles Bechoefer,
Presiding Officer

In the Matter of	**Docket Nos. 50-333-LT and 50-286-LT (consolidated)**
POWER AUTHORITY OF THE STATE OF NEW YORK and ENTERGY NUCLEAR FITZPATRICK LLC, ENTERGY NUCLEAR INDIAN POINT 3 LLC, and ENTERGY NUCLEAR OPERATIONS, INC.	**ASLBP No. 01-785-02-LT**
(James A. FitzPatrick Nuclear Power Plant and Indian Point Nuclear Generating Unit No. 3)	**February 23, 2001**

TESTIMONY OF DAVID A. LOCHBAUM, NUCLEAR SAFETY ENGINEER, UNION OF CONCERNED SCIENTISTS, REGARDING TECHNICAL ISSUES AND SAFETY MATTERS INVOLVED IN THE PROPOSED TRANSFER OF THE FITZPATRICK AND INDIAN POINT 3 OPERATING LICENSES TO ENTERGY NUCLEAR

I, David A. Lochbaum, submit the following testimony:

1. My name is David A. Lochbaum. I reside in the state of Maryland.

2. I am employed by the Union of Concerned Scientists as their nuclear safety engineer. I have been so employed since October 1996. The Union of Concerned Scientists, with offices located at 1707 H Street NW Suite 600, Washington, DC 20006, is an independent nonprofit organization dedicated to advancing responsible public policies in areas where technology plays a critical role.

3. I have the following responsibilities at UCS: a) direct and coordinate nuclear safety program; b) monitor developments in nuclear industry to assess and respond to impact; c) serve as technical authority and spokesperson on nuclear issues; and d) initiate legal action to correct safety problems.

4. I have worked in the field of nuclear engineering since June 1979. I am a graduate of the University of Tennessee with a bachelor of science in nuclear engineering.

5. After receiving my nuclear engineering degree, I went to work for the Georgia Power Company as a junior engineer at their Edwin I. Hatch Nuclear Power Plant. I held various positions in the commercial nuclear power industry over the next 17 years prior to joining UCS. This experience is detailed in the resume attached hereto as Exhibit A.

6. For approximately three years beginning in September 1992, I worked as a consultant to the New York Power Authority (NYPA) in their offices in White Plains, New York. My assignments included preparing the design bases document for primary containment isolation devices for the James A. FitzPatrick Nuclear Power Plant, coordinating the closure of design document open items for the FitzPatrick plant, and for coordinating the turnover of responsibility for maintaining design bases documents from the White Plains office to onsite organizations at the FitzPatrick and Indian Point 3 nuclear plants.

7. I am the author of *Nuclear Waste Disposal Crisis* (Pennwell Books, Tulsa, January 1996) on the technical problems with spent fuel storage at reactor sites and numerous reports for UCS on nuclear safety issues.

8. At the request of the Citizen's Awareness Network (CAN), I have examined the issue of the FitzPatrick (JAF) and Indian Point Unit 3 (IP3) nuclear plants operating at or above 85 percent capacity factors. I have relied upon publicly available information and my experience in formulating my opinions as expressed in this testimony.

9. Having examined the relevant documents as mentioned above, it is my professional opinion that it is uncertain that JAF and IP3 will be capable of sustained operation at or above 85% capacity factor. Using Nuclear Regulatory Commission data,[1] I examined the annual capacity factors for the 103 operating nuclear power plants for the period from 1994 to 1999, inclusive.[2] My conclusion is based upon the following facts:

---

[1] Nuclear Regulatory Commission, NUREG-1350 Vol. 12, "Information Digest 2000 Edition," June 2000 Available online at: http://www.nrc.gov/NRC/NUREGS/SR1350/V12/sr1350v12.html

[2] Although Browns Ferry Unit 1 was included in the NRC's digest as an operating plant, I excluded it from my analysis because the reactor has been shut down since March 1985. Including this unit would have reinforced rather than undermined my conclusions.

a) More units had annual capacity factors under 85 percent (309) than at or above 85 percent (307).[3]

b) The average annual capacity factor was 79.3 percent.

c) IP3 had more annual capacity factors under 85 percent (4) than at or above 85 percent (2).

d) IP3 had an average annual capacity factor of 52.3 percent.

e) JAF had more annual capacity factors under 85 percent (4) than at or above 85 percent (2).

f) JAF had an average annual capacity factor of 80.7 percent.

g) IP3 and JAF combined had more annual capacity factors under 85 percent (8) than at or above 85 percent (4).

h) IP3 and JAF had an average annual capacity factor of 66.5 percent.

i) Forty-eight (48) units had average annual capacity factors below 85 percent.

j) There were 19 instances where a reactor unit had an annual capacity factor of zero.

10. It is my professional opinion that the uncertainty for assumed operating performance of JAF and IP3 raises potential safety issues. The assumed operating performance is a key element of Entergy's business plan. Failure to achieve the assumed performance levels might impair the ability of the owner to finance work activities at one or both facilities. For example, necessary maintenance tasks and/or inspections might be deferred. The NRC initiated an inquiry into a related area involving the Maine Yankee plant. During briefings in 1997, the NRC Commissioners probed the financial arrangement between Central Maine Power and its holding company because there were some indications that safety problems at the plant, such as those documented in the Independent Safety Assessment Team (ISAT) report issued by the NRC in October 1996,[4] may have resulted from insufficient funding. The ISAT report is enclosed as Exhibit B. Specifically, the NRC's ISAT had concluded:

---

[3] 103 reactors over a 6-year period would normally provide 618 annual capacity factor numbers. Only 616 are reported here because the Watts Bar plant was not in commercial operation during 1994 and 1995.

[4] Letter dated October 7, 1996, from Shirley Ann Jackson, Chairman, Nuclear Regulatory Commission, to Charles D. Frizzle, President, Maine Yankee Atomic Power Company.

> The economic pressures discussed in Section 4.3 [of the report] resulted in limitations on resources and interfered with the licensee's ability to complete projects and other efforts that would improve plant safety and testing activities. [from page vii of the Executive Summary]
>
> Management has effectively operated the plant within the budget constraints established by the owners. However, the limitations on resources have delayed and deferred plant upgrades, improvements, and lower priority corrective actions which did not meet the threshold for safety, regulatory compliance, or reliable production. Projects which would likely have prevented problems were unfunded because of budget limits. [from Section 4.3.3 of the report]

The NRC's inquiry was terminated before its completion when the plant's owner announced in August 1997 that it would not be restarting the reactor. The proposed license transfers for IP3 and JAF, predicated on uncertain and somewhat speculative operating performance levels, raises many of the same financial questions asked by the Commission about Maine Yankee. It seems necessary to answer them before permitting the transfers.

11. It is my professional opinion that the assumed performance levels may also provide disincentives for plant workers to freely report potential safety problems. An independent report[5] on conditions at Maine Yankee prior to its permanent closure (Exhibit C) documented concerns by plant workers that their jobs were in jeopardy if they raised safety concerns. Specifically, the report stated:

> The current economic and political environment is considered precarious, and Maine Yankee's survival is seen to be based on a formula of low cost and high production. There is an associated fear among many employees that highlighting any negative issues could endanger the plant's continued operation. No one wants to be responsible for a premature plant shutdown and decommissioning. [from pages 8 and 9]

Workers at IP3 and JAF may have similar fears if they believe that failing to achieve arbitrarily high capacity factors could result in permanent closure of those units. Their fears may be manifested in safety problems and potential safety problems not being reported. It seems necessary to determine with reasonable assurance that workers will not feel constrained in identifying safety issues before permitting the transfers.

12. It is my professional opinion that the license transfer may increase the likelihood that workers at IP3 and/or JAF experience human performance degradation caused by fatigue. UCS issued a report on overtime and staffing issues in 1999 (Exhibit D). Any

[5] Robert E. Bradford, Jacquel-Anne Chouinard, Richard H. Fallon, Jr., and Jeffrey D. E. Jefferies, "Cultural Assessment Team Report on Factors Affectng the Reporting of Issues and Concerns at Maine Yankee," May 14, 1996.

new owner of the nuclear plants, particularly a limited liability company that lacks the financial wherewithal of a regulatory utility company, may be tempted to lower operating costs by reducing the staff levels for the plants. The remaining staff members may be forced to work longer hours, thus increasing the potential for fatigue and fatigue-induced errors. Increased likelihood of worker errors directly corresponds to increased risk as documented in UCS's report.

13. It is my professional opinion that it is uncertain whether either IP3 or JAF will operate at or above 85 percent capacity as detailed in paragraph 9. It is my professional opinion that the transfers of the IP3 and JAF operating licenses will raise the potential safety issues described in paragraphs 10, 11, and 12. I am also of the professional opinion, and do so state here, that the risk to persons living in close proximity to the facilities could be increased by the proposed license transfers, and the risks and potential are real, not highly speculative, and should be taken very seriously.

I declare under penalty of perjury that the foregoing is true and correct.

Executed February 23, 2001

David A. Lochbaum
Union of Concerned Scientists
1707 H Street NW, Suite 600
Washington, DC 20006
(202) 223-6133

Exhibit A

David A. Lochbaum

Experience Summary

10/96 to date *Nuclear Safety Engineer, Union of Concerned Scientists*

Responsible for directing UCS's nuclear safety program, for monitoring developments in the nuclear industry, for serving as the organization's spokesperson on nuclear safety issues, and for initiating action to correct safety concerns.

11/87 to 09/96 *Senior Consultant, Enercon Services, Inc.*

Responsible for developing the conceptual design package for the alternate decay heat removal system, for closing out partially implemented modifications, reducing the backlog of engineering items, and providing training on design and licensing bases issues at the Perry Nuclear Power Plant.

Responsible for developing a topical report on the station blackout licensing bases for the Connecticut Yankee plant.

Responsible for vertical slice assessment of the spent fuel pit cooling system and for confirmation of licensing commitment implementation at the Salem Generating Station.

Responsible for developing the primary containment isolation devices design basis document, reviewing the emergency diesel generators design basis document, resolving design document open items, and updating design basis documents for the James A. FitzPatrick Nuclear Power Plant.

Responsible for the design review of balance of plant systems and generating engineering calculations to support the Power Uprate Program for the Susquehanna Steam Electric Station.

Responsible for developing the reactor engineer training program, revising reactor engineering technical and surveillance procedures and providing power manuevering recommendations at the Hope Creek Generating Station.

Responsible for supporting the lead BWR/6 Technical Specification Improvement Program and preparing licensing submittals for the Grand Gulf Nuclear Station.

03/87 to 08/87 *System Engineer, General Technical Services*

Responsible for reviewing the design of the condensate, feedwater and raw service systems for safe shutdown and restart capabilities for the Browns Ferry Nuclear Plant.

08/83 to 02/87 *Senior Engineer, Enercon Services, Inc.*

Responsible for performing startup and surveillance testing, developing core monitoring software, developing the reactor engineer training program, and supervising the reactor engineers and Shift Technical Advisors at the Grand Gulf Nuclear Station.

Experience Summary (continued)

10/81 to 08/83 *Reactor Engineer / Shift Technical Advisor, Tennessee Valley Authority*

Responsible for performing core management functions, administering the nuclear engineer training program, maintaining ASME Section XI program for the core spray and CRD systems, and covering STA shifts at the Browns Ferry Nuclear Plant.

06/81 to 10/81 *BWR Instructor, General Electric Company*

Responsible for developing administrative procedures for the Independent Safety Engineering Group (ISEG) at the Grand Gulf Nuclear Station.

01/80 to 06/81 *Reactor Engineer / Shift Technical Advisor, Tennessee Valley Authority*

Responsible for directing refueling floor activities, performing core management functions, maintaining ASME Section XI program for the RHR system, providing power manuevering recommendations and covering STA shifts at the Browns Ferry Nuclear Plant.

06/79 to 12/79 *Junior Engineer, Georgia Power Company*

Responsible for completing pre-operational testing of the radwaste solidification systems and developing design change packages for modifications to the liquid radwaste systems at the Edwin I. Hatch Nuclear Plant.

Education

June 1979 Bachelor of Science in Nuclear Engineering, The University of Tennessee at Knoxville

May 1980 Certification, Interim Shift Technical Advisor, TVA Browns Ferry Nuclear Plant

April 1982 Certification, Shift Technical Advisor, TVA Browns Ferry Nuclear Plant

Professional Affiliations

Member, American Nuclear Society (since 1978).

NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

CHAIRMAN

EXHIBIT B

October 7, 1996

'96 OCT -9 A11:18

PUBLIC DOCUMENT

Mr. Charles D. Frizzle, President
Maine Yankee Atomic Power Company
329 Bath Road
Brunswick, Maine 04011

Dear Mr. Frizzle:

I am forwarding the report on the Maine Yankee Atomic Power Station by the Nuclear Regulatory Commission's Independent Safety Assessment (ISA) team. The purpose of the ISA was to determine whether Maine Yankee was in conformity with its design and licensing bases; to assess operational safety performance; and to evaluate Maine Yankee's self-assessment, corrective actions, and plans for improvement.

Overall performance at Maine Yankee was considered adequate for operation. However, a number of significant weaknesses and deficiencies were identified that will result in violations. These weaknesses and deficiencies appear to be related to two root causes: economic pressures to contain costs and poor problem identification as a result of complacency and a lack of a questioning attitude.

The ISA review was conducted in response to findings made by the NRC's Office of the Inspector General (OIG) in a report dated May 8, 1996. It included an assessment of the analytic code support provided for Maine Yankee by the Yankee Atomic Electric Company. The OIG report found, among other things, that Maine Yankee had experienced problems with the RELAP/5YA computer code, used for analyzing how the emergency core cooling system would function during a small break loss-of-coolant accident (LOCA), and in response, had modified that code. OIG also found that these problems with the computer code had not been reported to the NRC, as required, and that because of these problems, Maine Yankee's use of the code was not in accordance with NRC requirements. NRC reviews did not uncover these deficiencies.

The team was large and multi-disciplined in order to provide a thorough, in-depth review. Its 25 members, led by an NRC manager, included three representatives of the State of Maine. To ensure an independent perspective, the NRC members were selected from NRC offices other than the Office of Nuclear Reactor Regulation (NRR) and the NRC's Region I. Only persons with no significant prior responsibility for regulating Maine Yankee were chosen. The team's management reported to me.

The ISA team was on site at Maine Yankee between July 15 and 26, 1996, and again between August 12 and 23, 1996. During these time periods, team members also conducted assessments at Maine Yankee's corporate headquarters in Brunswick, Maine, and at the Yankee Atomic Electric Company offices in Bolton, Massachusetts.

The ISA team reviewed the use of selected analytic codes for performing non-LOCA safety analyses, as well as the capability of the safety-related support systems to perform in accordance with the assumptions made in those analyses. The review determined that the conditions of approval in NRC Safety Evaluation Reports have been met although weaknesses in documentation and validation of plant specific code applications are vulnerabilities which warrant your attention.

The team determined that cycle-specific core performance analyses were excellent. However, weaknesses were found in more complicated, less frequently performed system safety analyses. These weaknesses did not cause the results to exceed Maine Yankee's design and licensing bases. However, the team questioned the capability of the containment spray system and the component cooling water systems to meet the design basis assumptions for a LOCA initiated from greater than 2440 MWt. These issues, along with the RELAP/5YA deficiencies, will be reviewed by NRC's Office of Nuclear Reactor Regulation.

The team identified significant deficiencies in the areas of maintenance and engineering, as well as weaknesses in the overall approach to testing and the corrective action program. Specifically, the lack of routine testing of certain safety systems resulted in the existence of a significant deficiency of which Maine Yankee was unaware. In addition, the ISA noted certain design errors. Either Maine Yankee was unaware of these errors, or it was aware of them and had failed to take action to address them.

I should add that Maine Yankee deserves credit for having formed a counterpart team of highly qualified personnel to interface with the ISA team during its review. The existence of this team was both helpful to the ISA team's activities and valuable as a means of ensuring that Maine Yankee learned as much as possible from this effort. In addition, it meant that as problem areas were identified, Maine Yankee was in a position to devote resources promptly to necessary corrective actions.

We have scheduled a meeting for October 10, 1996, during which we will discuss the assessment and respond to questions you may have. I request that following this meeting, you determine the actions needed to ensure the long-term resolution of the deficiencies noted. I also request that by December 10, 1996, you provide to the Commission your plans for addressing the root causes of the deficiencies identified by the ISA. The NRC's Region I and its Office of Nuclear Reactor Regulation will be responsible for followup of the issues identified in this assessment, in terms of overseeing corrective actions and taking any enforcement action deemed appropriate.

In accordance with 10 CFR 2.790(a), a copy of this letter and the enclosure will be placed in the NRC Public Document Room. Should you have any questions concerning this assessment, I would be pleased to discuss them with you.

Sincerely,

Shirley Ann Jackson

Enclosure:
Independent Safety Assessment Report
for Maine Yankee Atomic Power Company

cc: See page 4

cc w/enclosure:

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United States
Nuclear Regulatory Commission

INDEPENDENT SAFETY ASSESSMENT OF MAINE YANKEE ATOMIC POWER COMPANY

October 1996

Licensee:	Maine Yankee Atomic Power Company
Facility:	Maine Yankee Atomic Power Station
Location:	Wiscasset, Maine
Docket No:	50-309
Onsite Evaluation Period:	July 15-26, 1996, and August 12-23, 1996
Team Manager:	Edward L. Jordan
Team Leader:	Ellis W. Merschoff
Administrative Assistant:	Ola B. West
Team Members:	Larry Bell John R. Boardman Russell L. Bywater, Jr. Harold O. Christensen George M. Hausman John V. Kauffman Kriss M. Kennedy G. Norman Lauben Ronald L. Lloyd Alan L. Madison Thomas O. Martin Peter J. Prescott Jack E. Rosenthal
State Representatives:	David Decrow Patrick Dostie Uldis Vanags
Contractors:	George Cha Robert Christie Cyril Crane Brian Haagensen Michael Shlyamberg Leonard Ward

Submitted By: Ellis W. Merschoff, Team Leader — Date: 10/7/96

Approved By: Edward L. Jordan, Team Manager — Date: 10/7/96

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EXECUTIVE SUMMARY

Background

In December 1995, the Union of Concerned Scientists forwarded anonymous allegations to the State of Maine, and the State submitted the allegations to the NRC. The allegations were that Yankee Atomic Electric Company knowingly performed inadequate analyses to support an increase in the rated thermal power at which Maine Yankee Atomic Power Station (MYAPS) may operate. After performing a technical review, the NRC Office of Nuclear Reactor Regulation (NRR) issued a confirmatory order on January 3, 1996, limiting power operation at the plant to the original licensed power level of 2440 MWt.

The NRC Office of the Inspector General (OIG) completed an inquiry into this allegation on May 8, 1996. OIG established that MYAPS had experienced problems with, and made modifications to, the RELAP/5YA computer code which was used in the emergency core cooling analysis for a small-break loss-of-coolant accident. OIG also reported weaknesses in the NRC review and followup activities which contributed to NRC failure to detect these deficiencies. In response to these findings, as well as to respond to concerns by the Governor of Maine about the safety and the effectiveness of regulatory oversight of MYAPS, the NRC Chairman initiated an independent safety assessment of MYAPS. This assessment was to be performed by a team comprised of staff who were independent of any recent or significant regulatory oversight responsibility for MYAPS. Additionally, the assessment was to be coordinated with the State of Maine to facilitate participation by State representatives consistent with the Commission's policy on cooperation with States at commercial nuclear power plants (57 FR 6462, February 25, 1992).

Licensing and Design-Basis

Maine Yankee was in general conformance with its licensing-basis although significant items of non-conformance were identified. The licensing-basis was understood by the licensee but lacked specificity, contained inconsistencies, and had not been well maintained.

The use of analytic codes for safety analyses was very good. Cycle specific core performance analyses were excellent. More complicated, less frequently performed safety analyses contained weaknesses, but the analyses were found to be acceptable based on compensating margin. Conditions of use specified in the safety evaluation reports were found to be satisfied, but not documented.

The quality and availability of design-basis information was good overall. Despite uncorrected and previously undiscovered design problems, the design-basis and compensatory measures adequately supported plant operation at a power level of 2440 MWt. However, the team could not conclude, and the licensee did not demonstrate, that at a power of 2700 MWt the design-basis assured adequate NPSH for the containment spray pumps and the heat removal capability of the component cooling water system in the event of a loss-of-coolant accident.

Operations

Performance in the area of operations was very good, with strengths noted in the areas of operator performance during routine and transient operating conditions; shift turnovers and pre-evolution briefs; use of risk information to assure safe operations; and the involvement of management in day-to-day operations. Weaknesses were noted in the area of "workarounds" and compensatory measures which unnecessarily burdened the operators or complicated their response to transient conditions. Additionally, log keeping practices and post-trip reviews lacked rigor.

Maintenance and Testing

Performance in the area of maintenance was good overall however, testing was weak. The results of the review of equipment reliability for the auxiliary feedwater, emergency feedwater, high pressure safety injection, and emergency diesel generator systems showed mixed equipment performance. Strengths were noted in the areas of knowledge and use of risk methodologies for planning, prioritizing, and scheduling work; the control and limited use of temporary sealants; and a motivated and dedicated work force. Although material condition was considered good overall, a number of significant material condition deficiencies were noted as was a decline in material condition following the 1995 steam generator tubing outage.

Inadequacies in the scope of testing programs were identified, as were weaknesses in the rigor with which testing was performed and in the evaluation of testing results to demonstrate functionality of safety equipment. A lack of a questioning attitude and stressed resources resulted in the use of poor surveillance procedures and ineffective evaluation of surveillance test data.

Engineering

The quality of engineering work was mixed but considered good overall. Strengths were noted in the capability and experience of the engineering staff, day-to-day engineering support of maintenance and operations, in the quality of most calculations, and in the routine use and application of analytic codes. However, engineering was stressed by a shortage of resources, and there was a tendency to accept existing conditions. Specific weaknesses were noted with inconsistent identification and resolution of problems, inadequate testing, and work on some calculations and analytic codes.

Self Assessment and Corrective Actions

Weaknesses were identified in the areas of problem identification and resolution. While licensee self-assessments were generally good, they occasionally failed to identify weaknesses or incorrectly characterized the significance of the findings. Additionally, some corrective actions were not timely and others were ineffective, leading to repetitive problems. Licensee planning was generally effective, although some weaknesses were found in the overall implementation of improvement plans. Some economic pressures resulted in limitations on resources, which impaired the licensee's ability to complete

improvement projects that affected plant safety. Equipment problems were not resolved and improvement programs were not effectively implemented because the licensee perceived them to be of low safety significance.

Root Causes and Overall Conclusions

While overall performance at Maine Yankee was adequate for operation, a number of deficiencies were identified by the team in each of the areas assessed. These deficiencies, which included weak identification and resolution of problems; weak scope, rigor, and evaluation of testing; and declining material condition stemmed from two closely related root causes. These root causes were (1) economic pressure to be a low-cost energy producer has limited available resources to address corrective actions and some plant improvement upgrades and (2) there is a lack of a questioning culture which has resulted in the failure to identify or promptly correct significant problems in areas perceived by management to be of low safety significance.

The economic pressures discussed in Section 4.3 resulted in limitations on resources and interfered with the licensee's ability to complete projects and other efforts that would improve plant safety and testing activities. Examples include the failure to adequately test safety related components (Section 3.2.4); the long-standing deficient design conditions, such as the undersized atmospheric steam dump valve (Sections 3.1.3.1 and 3.3.1) and environmental qualification issues (Section 2.3.9); and the lack of effective improvement programs, such as the design basis reconstitution program (Sections 3.3.3 and 4.3.3). These and other examples discussed in the report illustrate the licensee's willingness to accept existing conditions, many of which became operator workarounds (Section 3.1.1.1).

Examples of issues which illustrate complacency and the failure to identify or promptly correct significant problems, include previously undiscovered deficient conditions of the service water and auxiliary feedwater water systems (Section 3.2.2); inadequacies in ventilation systems (Section 2.3.7); post-trip reviews which lacked rigor and completeness (Section 3.1.2.7); emergency operating procedures that may not adequately address an inadequate core cooling event and a steam generator tube rupture under certain conditions (Section 3.1.3.1); lack of a questioning attitude during test performance and evaluation that was not conducive to discovering equipment problems, but rather to accepting equipment performance (Sections 2.2.1, 3.2.2, 3.2.4); and licensee self-assessments that occasionally failed to identify weaknesses, or incorrectly characterized the significance of findings (Section 4.1). In addition, some corrective actions were not timely and others were ineffective, leading to repetitive problems (Section 4.2).

1.0 INTRODUCTION

1.1 Background

In December 1995, the Union of Concerned Scientists forwarded anonymous allegations to the State of Maine, and the State submitted the allegations to the NRC. The allegations were that Yankee Atomic Electric Company knowingly performed inadequate analyses to support an increase in the rated thermal power at which Maine Yankee Atomic Power Station (MYAPS) may operate. After performing a technical review, the NRC Office of Nuclear Reactor Regulation (NRR) issued a confirmatory order on January 3, 1996, limiting power operation at the plant to the original licensed power level of 2440 MWt.

The NRC Office of the Inspector General (OIG) completed an inquiry into this allegation on May 8, 1996. OIG established that MYAPS had experienced problems with, and made modifications to, the RELAP/5YA computer code which was used in the emergency core cooling analysis for a small-break loss-of-coolant accident. The problems and subsequent modifications were not reported to the NRC as is required and the code was not used in accordance with the Safety Evaluation Report and with the Three Mile Island Action Plan Item II.K.3.3.1. OIG also reported weaknesses in the NRC review and followup activities which contributed to NRC failure to detect these deficiencies.

The RELAP issue raised a question of whether similar problems existed in other areas. In order to address this question, as well as to respond to concerns by the Governor of Maine about the safety and the effectiveness of regulatory oversight of Maine Yankee, the NRC Chairman initiated an independent safety assessment of MYAPS. This assessment was to be performed by a team comprised of staff who were independent of any recent or significant regulatory oversight responsibility for Maine Yankee. Additionally, the assessment was to be coordinated with the State of Maine to facilitate participation by State representatives consistent with the Commission's policy on cooperation with States at commercial nuclear power plants (57 FR 6462, February 25, 1992). The RELAP issue was the subject of a separate NRC investigation and was not considered part of this assessment.

1.2 Scope and Objectives

On May 31, 1996, the staff was directed to perform an independent evaluation of Maine Yankee's safety performance. The overall goals of the independent safety assessment were to: (1) independently assess the conformance of MYAPS to its design and licensing bases including appropriate reviews at the site and corporate offices; (2) independently assess operational safety performance giving risk perspectives where appropriate; (3) evaluate the effectiveness of licensee self-assessments, corrective actions, and improvement plans; (4) determine the root cause(s) of safety-significant findings and draw conclusions on overall performance.

1.3 Methodology

The Independent Safety Assessment (ISA) team comprised 25 members: 16 NRC members, 3 State of Maine members, and 6 contractors. The team was organized with five functional area leaders reporting to a team leader. The team leader reported to the team manager who reported directly to the NRC Chairman. The ISA team members were independent of both the NRC Region I office and NRR. The team devoted several weeks to preparation that included team meetings and briefings by the staffs from Region I, NRR, the Office for Analysis and Evaluation of Operational Data (AEOD), the Office of Investigations and OIG. On July 15, 1996, the team began a two-week evaluation at the facility, including the corporate office and the Yankee Atomic Electric Company offices. The team returned to Maine Yankee on August 12, 1996, for an additional two weeks of evaluation. The representatives from the team met daily with their licensee counterparts to discuss team findings.

In addition to the State of Maine's participation in the assessment, the State had a two-member process team observe at key assessment milestones. The process team provided the State with an assessment of the ISA relative to its fairness, balance, and objectivity. The State also had a special five-member citizen's review team periodically briefed on the ISA team status. The citizen's review team provided the State advice on and interpretations of the ISA team process and findings.

An indepth assessment was conducted in the areas of plant operations, maintenance, testing, engineering, analytic code support, and self-assessment and corrective actions. The assessment consisted of interviews; system walkdowns; extended control room observations; system reviews of service water, high pressure safety injection, and emergency diesel generators; program, process, and procedure reviews; and analytic code reviews. In addition, an extensive reliability analysis of auxiliay feedwater, emergency feedwater, high pressure injection, and emergency diesel generator systems was performed. Emphasis was placed on identifying both licensee strengths and performance weaknesses.

The assessment relied on the existing NRC benchmark for assessing performance utilized in the NRC Systematic Assessment of Licensee Performance Program (SALP). Specifically:

- Superior performance is defined as follows:

  Licensee attention and involvement have been properly focused on safety and resulted in a superior level of safety performance. Licensee programs and procedures have provided effective controls. The licensee's self-assessment efforts have been effective in the identification of emergent issues. Corrective actions are technically sound, comprehensive, and thorough. Recurring problems are eliminated and resolution of issues is timely. Root cause analyses are thorough.

- Good performance is defined as follows:

  Licensee attention and involvement are normally well focused and resulted in a good level of safety performance. Licensee programs and procedures normally provide the necessary control of activities, but deficiencies may exist. The licensee's self-assessments are normally good, although issues may escape identification. Corrective actions are usually effective, although some may not be complete. Root cause analyses are normally thorough.

- Acceptable performance is defined as follows:

  Licensee attention and involvement have resulted in an acceptable level of safety performance. However, licensee performance may exhibit one or more of the following characteristics. Licensee programs and procedures have not provided sufficient control of activities in important areas. The licensee's self-assessment efforts may not occur until after a potential problem becomes apparent. A clear understanding of the safety implications of significant issues may not have been demonstrated. Numerous minor issues combine to indicate that the licensee's corrective action is not thorough. Root cause analyses do not probe deeply enough, resulting in the incomplete resolution of issues.

One area of this assessment, review of the use and application of analytic codes, is not typically reviewed as part of the NRC regulatory process. Consequently, a panel of acknowledged experts in the area of code development and phenomenology were assembled and provided a critical review of the findings and observations of the ISA team in this area.

1.4 Facility Description

The Maine Yankee Atomic Power Station is located in the tidewater area on Bailey Point Road in Wiscasset, Maine. The plant is a Combustion Engineering pressurized-water reactor. The facility was constructed by Stone & Webster, which also served as the architectural engineer. The full power operating license was issued on June 29, 1973.

1.5 Organization

The Maine Yankee Atomic Power Station is owned and operated by the Maine Yankee Atomic Power Company. The chart, Appendix B, illustrates the Maine Yankee organizational structure for management and support of the Maine Yankee Atomic Power Station.

2.0 CONFORMANCE TO DESIGN AND LICENSING BASIS

This section describes the conformance of Maine Yankee to its design and licensing-basis. Significant aspects of the design of Maine Yankee were based on handling "worst case" situations such as a postulated rupture of a main steam line or a large break of reactor coolant system piping along with additional assumptions, such as, the failure of mitigating equipment coincident with a loss of offsite power. This approach establishes the deterministic licensing basis. This deterministic approach along with conservative design, effective maintenance, and thorough testing provides an inherent margin of safety and defense-in-depth to cope with actual transients and accidents that may occur.

To confirm plant conformance to the licensing basis, the team reviewed transient and accident analyses (see Section 2.1), and equipment design issues (see Sections 2.2 and 2.3). Discrepancies between actual operations, safety analyses, design features and capability, and descriptive and numerical values contained in the Final Safety Analyses Report (FSAR) are summarized in Section 2.4.

2.1 Transient and Accident Safety Analyses

Cycle-specific core performance analyses, such as the Control Element Assembly (CEA) drop transient described below, were excellent.

More complicated, less frequently performed systems safety analyses contained weaknesses, such as those associated with the steam line rupture accident, but the analyses were found to be acceptable based on compensating margin. Overall, use of analytic codes for safety analyses was very good. SER conditions were found to be satisfied but not documented. Code validation was mixed: excellent for physics and fuel codes, while weak for systems codes.

2.1.1. Analytic Code Support

The team evaluated the analytic code support provided by Yankee Atomic Electric Company (YAEC) for Maine Yankee Atomic Power Company (MYAPCo) to assure that Maine Yankee was operated within the bounds of the safety analyses. This assessment was performed by reviewing the YAEC process for conducting non-LOCA safety analyses described in Chapter 14 of the FSAR, and an indepth review of two specific safety analyses: the CEA drop transient and the steam line rupture accident. Selection of the dropped CEA transient for in-depth review provided a structured means to examine many of the codes used by YAEC while selection of the steam line rupture analysis for review provided a forum for reviewing a dynamic accident analyzed with a complex systems code.

The overall review included: (1) identification of the design-basis analyses for postulated accidents and anticipated operational occurrences, (2) identification of codes, methods, and limitations, based on the team's review of topical reports and NRC safety evaluation reports (SERs), (3) an assessment of how limitations, restrictions, and boundary conditions are reflected in the safety analyses. Central to the assessment was the verification that conditions of approval contained in NRC SERs had been satisfied in the safety

analyses. The ISA team also specifically examined code validation using guidance contained in Generic Letter (GL) 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions," February 8, 1983.

All analytic codes used for the current fuel cycle (Cycle 15) reference analyses, and a matrix of codes and transient and accident analyses applications are shown in Tables 1 and 2, respectively. Analytic methods are listed in Maine Yankee Technical Specification 5.14.2 and in the Core Performance Analyses Report for Cycle 15 (YAEC 1907, Revision 2), which is also Appendix D of the FSAR. As indicated in Table 1, "Maine Yankee Analytical Codes for Fuel Cycle 15", most SERs contained conditions of approval. Table 2, Codes Used for Key Transients, shows the application of the codes and methods to specific transient and accident analyses.

Table 1

MAINE YANKEE ANALYTIC CODES FOR FUEL CYCLE 15

CODE NAME	FUNCTION	NO. Of SER CONDITIONS[1]
CASMO-3G	Physics	1
SIMULATE-3	Physics	2
STAR	Physics - Space/Time	2
FROSSTEY-2	Fuel Performance	4
COBRA-IIIC Generic	Core and Fuel Hydraulic	11[2]
COBRA-IIIC Plant Specific	Core and Fuel Hydraulic	0
YAEC-1 CHF	Critical Heat Flux Correlation	2
SCU	Statistical Uncertainties Applied to Thermal Margin Setpoints	0
RETRAN 02 Mod 2 Generic	System Thermal Hydraulic	39
RETRAN 02 Mod 2 Plant Specific	System Thermal Hydraulic	0
BIRP	Reactivity Balance	0
CHIC-KIN	Integrated Single Channel Fuel, T/H, Physics	0
GEMINI-II	System Thermal Hydraulic	5

[1] SER conditions are limitations, application restrictions, and verification and validation issues within which the code and application are judged acceptable to the staff.

[2] Conditions for COBRA-IIIC Generic are imposed by the author and are described in the Topical Report BNWL-1695.

Table 2

Codes Used for Key Transients

TRANSIENT[1]	FROSSTEY-2	GEMINI-II	COBRA-IIIC	RPS SETPOINT	YAEC-1 CHF	SCU	HAND CALC	RETRAN 02 MOD 2	CHICKEN/ STAR
CEA DROP	X	X	X	X	X	X			
CEA WITHDRAWAL	X	X	X	X	X	X			
BORON DILUTION							X		
LOSS OF FLOW	X		X	X	X	X			X
SEIZED ROTOR	X		X	X	X	X			X
EXCESS LOAD	X	X	X	X	X	X			
LOSS OF LOAD	X	X	X	X	X	X			
LOSS OF FEEDWATER	X	X	X	X	X	X			
MAIN STEAM LINE RUPTURE								X	
CEA EJECTION									X
STEAM GENERATOR TUBE RUPTURE							X		

[1] CASMO-3G and SIMULATE-3 are used to prepare input for all the transient calculations

2.1.2 SER Conditions Satisfied But Not Documented

The ISA team found that YAEC calculations of transients and accidents conformed to all applicable SER conditions. In some cases SER conditions were explicit and readily verified. In other cases SER conditions were requests to provide justification for certain models, the selection of correlations, and inputs. In these cases the ISA team reviewed the conditions within the context of the code application.

YAEC did not have a written process to document how safety analyses conformed to SER conditions. Some conditions were clearly known, considered, and used by YAEC. Other conditions could not be shown to be satisfied until additional analyses, assessments, and sensitivity studies, were accomplished in response to ISA requests. This new work demonstrated that all SER conditions had been satisfied, although the disposition of some issues required reliance on the known conservatisms in specific accident analyses.

2.1.3 Control Element Assembly Drop Transient

The CEA drop transient analysis which used many of the YAEC codes and methods, was performed in an excellent manner.

The CEA drop was one of the 10 non-LOCA transients normally reanalyzed for each cycle. The following set of NRC-approved codes and methods was used: CASMO-3G/TABLES-3, SIMULATE-3, FROSSTEY-2, GEMINI-II, COBRA-IIIC (YAEC-1 DNB), Reactor Protective System (RPS) setpoint methodology, and Statistical Combination of Uncertainties (SCU).

Predicted fuel bundle and fuel rod power distributions were obtained from the physics code SIMULATE-3, which in turn used neutron cross sections from CASMO-3G. An ISA team review of predicted and measured fuel bundle power distributions showed excellent agreement over several fuel cycles.

FROSSTEY-2 was a steady-state fuel performance code used to calculate margin to fuel centerline melt using bounding values from a large number of fuel rod powers and power shapes. The FROSSTEY-2 SER review was performed by the authors of its predecessor code, GAPCON-THERMAL. There were numerous iterations between YAEC and the reviewers, and substantive modifications to the code resulted. The two SER conditions on FROSSTEY-2 were straightforward: (1) a local burnup limit of 60,000 MWd/MTU and (2) the inclusion of fuel manufacturing uncertainties. The local burnup limit was administratively controlled at Maine Yankee, and manufacturing tolerances were accounted for in the statistical combination of uncertainties. For code validation, FROSSTEY-2 was compared to a significant PWR fuels data base. Probability/confidence limits of 95/95 for centerline melt temperature were used which included code and input uncertainties and were a function of fuel burnup. Fuel performance calculations considered the multiple fuel types and multiple projected burnup histories, and were excellent overall.

GEMINI-II was a simplified systems code used to predict changes in reactor coolant system (RCS) pressure and core inlet temperature associated with the CEA drop transient. YAEC used the minimum RCS pressure calculated with

GEMINI-II for the COBRA-IIIC subchannel analysis which was a conservative assumption. Since the GEMINI calculated transient temperatures were less than maximum core inlet temperatures contained in the plant Technical Specifications (TS), the TS value was used in the COBRA subchannel analyses, again a conservative assumption. GEMINI-II contained a very simplified treatment of reactor coolant and secondary systems. The RCS was modeled as four lumped volumes where fluid mass was constant and subcooled, and the secondary system was modeled as a single saturated volume. The pressurizer model contains two regions in which equations for mass and energy were solved. Interfacial heat transfer in the pressurizer was zero. Steam-to-wall heat transfer was not modeled. There was a point kinetics model of the core. An energy balance was performed by the code. Benchmarking of the code was minimal. Despite its simplicity, the mild thermal-hydraulic transient associated with the CEA drop transient (i.e., small changes in reactor power, pressure, and temperature) was not a challenge to the modeling approach in GEMINI-II, and was acceptable for this application.

COBRA-IIIC was a multiple channel core fluid behavior and departure from nucleate boiling (DNB) analysis code, which was used twice in the YAEC methodology for DNB. COBRA-IIIC was first used to model a one-eighth symmetric core section using vendor-supplied fuel assembly flow resistances to determine an inlet flow penalty to be used in subchannel DNB analyses. The penalty was determined conservatively from bundle-sized hydraulic parameters and power factors. Next, COBRA-IIIC subchannel analyses were performed to determine individual subchannel DNB limits. This was done for a collection of adjacent pins and sub-channels that had a high probability of reaching DNB. This analysis used the most limiting of a large number of fuel pin power levels and axial power profiles using conservative values for inlet flow, inlet temperature, and system pressure.

The YAEC-1 DNB correlation used by YAEC in the second COBRA-IIIC analyses discussed above was developed from a substantial number of experiments at Columbia University using 14X14 fuel simulators of the exact geometry originally used in Maine Yankee. The data, the COBRA code, the correlation, and associated biases and statistical combination of uncertainties were a matched set used to establish a minimum DNB.

The ISA team discussed the YAEC application of COBRA III-C with the code authors. In BNWL-1695[3], the author of the original COBRA code, stated that all 11 user-selected correlations should be justified. One of the COBRA IIIC authors told the ISA team that the selections of correlations by YAEC were reasonable as long as the selections remained constant for the application as well as for the development of the DNBR correlation. This was the correct procedure and was followed by YAEC.

The Cycle 15 core consisted of a mixture of Combustion Engineering, Siemens, and Westinghouse fuel. Fuel procurement specifications were used to assure

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[3]D. S. Rowe, "COBRA III C: A Digital Computer Program for Steady State and Transient Thermal - Hydraudic Analysis of Rod Bundle Nuclear Fuel Elements, " March 1973, Battelle, Pacific Northwest Laboratories

that minimal geometric differences affecting DNBR would exist among different fuels within the same reload. YAEC has also required vendor flow testing to assure that appropriate flow resistances were applied in the one-eighth core analyses for determining flow penalties.

Overall the CEA drop analyses performed by YAEC for Maine Yankee was found to be excellent for the following reasons:

(1) Power distributions were found to be accurate and uncertainties treated appropriately.

(2) The GEMINI analysis was applied in a conservative manner for the CEA drop transient.

(3) The fuel centerline melt analyses using FROSSTEY-2 with uncertainties was found to be conservative.

(4) The consistent application of the Columbia University DNB tests, the COBRA-IIIC code, the YAEC-1 correlation, and the statistical combination of uncertainties was appropriate.

(5) Careful fuel procurement specifications and application of inlet flow penalties provided confidence that DNB analyses with mixed cores is done appropriately.

2.1.4 Main Steam Line Rupture

Although weaknesses were found, the main steam line rupture analysis was found to be acceptable due to compensating conservatisms.

YAEC used the RETRAN 02 MOD 2 and Boron Injection RETRAN Post-processor (BIRP) codes for analyses of the main steam line rupture (MSLR) event for Cycle 15. RETRAN 02 MOD 2 was used to simulate the primary and secondary system thermal-hydraulic responses following an MSLR. BIRP was used to calculate the reactivity feedback associated with the steam line rupture and consequential primary system cooldown.

YAEC performed calculations for a spectrum of MSLR cases for Cycle 9 including cases at hot full power (HFP) and zero power, for a range of postulated equipment failures. For Cycle 11, the calculation for the bounding HFP case was repeated and was the reference for the current Cycle 15 analyses. For Cycle 15, only reactivity effects were recalculated.

RETRAN 02 MOD 2 was a one-dimensional thermal-hydraulic computer program intended for use in analyzing the consequences of operational transients in light water reactors. The code solved the equations of continuity, energy, and momentum to simulate the primary and secondary fluid temperature and pressure. The code contained an equilibrium formulation with non-equilibrium conditions modeled in the pressurizer and reactor vessel upper head. Core heat transfer was simulated with a one-dimensional heat-conduction model in which the boiling curve was employed to treat the convective heat transfer between the fluid and the fuel rods. Point kinetics were used to compute core power. A

bubble rise model was employed to treat two-phase flow and phase separation effects. This code was provided through the Electric Power Research Institute (EPRI) and has an extensive user group.

The Boron Injection RETRAN Post-processor (BIRP) was a separate code used to evaluate the reactivity feedback effects to determine the potential for a return to criticality during the MSLR. It used RETRAN 02 MOD 2 thermal-hydraulic results as input. BIRP was used to calculate the soluble boron concentration due to safety injection during the steam line rupture, as well as the overall reactivity balance.

The NRC issued an SER on the use of RETRAN 02 MOD 2 and BIRP on October 2, 1985, with no SER conditions for the Maine Yankee plant-specific analyses. However, a generic SER with 39 SER conditions was issued on September 4, 1984, regarding the use of RETRAN 02 MOD 2. The ISA team reviewed these conditions within the context of the MSLR application to Maine Yankee. Nine conditions did not apply to PWRs. Another 22 conditions were explicitly met because of the modeling approach and application to the MSLR. The remaining eight conditions all involve modeling and validation and are subject to interpretation. On the basis of sensitivity studies performed by YAEC and compensating conservatism in the MSLR analyses described below, the ISA team concluded that these conditions had been satisfactorily addressed.

During the assessment, the team found a number of errors and inconsistencies. YAEC performed several sensitivity studies to quantify the issues for the team. Following is a discussion of the more substantive issues.

(1) The pressurizer and reactor vessel upper-head interfacial heat-transfer coefficient was assumed to be 1000 Btu/hr-ft^2-°F. This coefficient was non-physical and inconsistent with the test data in the literature such as the Massachusetts Institute of Technology (MIT) pressurizer data . Use of this coefficient is incorrect; however, MSLR results were unaffected by this assumption since it is a depressurization event.

(2) There was a lack of RETRAN 02 MOD 2 benchmarking against separate-effects and integral and plant data; for example, MIT pressurizer data, Shippingport plant data, Loss of Fluid Test (LOFT) loss-of-load test, and MSLR integral tests.

(3) Liquid flow spikes were observed in steam line break flow, violating the model assumption that only pure steam exits the break to maximize the cooldown. This demonstrated that an error existed in the bubble-rise model in the code. However, the overall cooldown was unaffected by these spikes.

(4) A possible non-conservative omission in the RETRAN 02 MOD 2 enthalpy transport model was found. The work term (PV) in the total energy equation was intentionally omitted as a simplification to the code. This omission could produce enthalpies exiting the core and steam generators that were too high, thereby decreasing the cooldown rate. The evaluation of the effect of this term indicates a less-than-5 °F variation in the steam generator and core exit temperatures.

(5) There were no justifications or sensitivity studies for the assumed fluid mixing in the RCS. Use of scaled flow data to justify modeling of the reactor vessel lower plenum and upper plenum as single nodes was inappropriate since the data did not include the asymmetric temperatures reflective of the MSLR event. Subsequent sensitivity studies performed by YAEC for the ISA team showed that although the initial cooldown progresses at a faster rate early in the transient when a split core rather than a single channel was modeled, the minimum temperature achieved during the MSLR did not change.

(6) An inadvertent switch in secondary-side heat transfer from nucleate boiling to transition boiling and forced convection to steam was noted in the hot zero power analyses. YAEC corrected this error and the new results showed that the full-power MSLR analyses remained limiting. However the hot zero power cases were very close to the limiting full power case.

The MSLR analysis was judged to be bounding because the modeling of the heat removal from the secondary side of the steam generator resulted in an excessively low RCS temperature. The conservatively low predicted temperature was supported by the following conservatisms and supporting analyses:

(1) In the calculation, the heat extraction by the secondary side was not degraded as the secondary level decreased. The full heat removal capability was assumed until all of the secondary liquid was boiled off.

(2) Comparisons of the YAEC secondary-side modeling approach to an MSLR test at the LOBI[4] test facility showed that the YAEC approach conservatively under-predicted the test data. While the LOBI test cannot be directly used to quantify the conservatism of the MSLR calculation due to scaling and modeling issues, simulation of the LOBI test[5] with RETRAN 02 MOD 2 qualitatively demonstrated the conservatism.

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[4] LOBI, Loop Blowdown Investigation Facility

[5] "Pretest Predictions for a LOBI-MOD2 Large Steam Line Break" by P. Lightfoot, J. Burchley, J. Rogers. Procedings to the 5th International RETRAN Conference EPRI NP-5781-SR April 1988

2.1.5 Lack Of A Documented Process To Demonstrate Code Capability

YAEC did not have a documented process in place to identify and rank key phenomena for each of the transients and accidents in the safety analyses report and in turn identify needed code validation and parametric study efforts. Some codes, such as the physics and DNB codes, were found to have extensive validation to actual plant measurements and experimental data respectively. In contrast, the ISA team found that there was overreliance on industry RETRAN validation efforts, and that validation of RETRAN for the MSLR accident at YAEC was weak. During the ISA, YAEC initiated the writing of a "Methods Overview Manual" which was intended to address these issues.

2.2 Design Review Of Selected Systems

The ISA team conducted an in-depth design review of: (1) the high-pressure-safety injection (HPSI) system; (2) service water, which included the service water (SW) system, the primary component cooling water (PCCW) system, and the secondary component cooling water (SCCW) system; and (3) the electrical system, particularly as it pertained to HPSI and SW. This design review consisted of an evaluation of the ability of these systems, as modified, maintained, tested, and operated by the licensee, to perform their intended safety functions through an in-depth review of the work of the various engineering disciplines (mechanical, electrical, instrument and controls).

2.2.1 High-Pressure-Safety Injection (HPSI) System

As a result of the ISA team's finding that the circuitry of one of the containment spray pumps (P-61S) and the recirculation actuation system (RAS) manual switch was not periodically tested, the licensee discovered that HPSI pump P-14A would not have actuated automatically after a loss-of-coolant accident (LOCA) with offsite power available. The ability of the containment spray (CS) system to provide a reliable supply of water to HPSI pump suction during the recirculation phase of a LOCA was not adequately demonstrated for plant operation at power levels above 2440 MWt due to the potential for CS pump cavitation. With these exceptions, the ISA team found that the HPSI system would have functioned as intended; however, other weaknesses were noted with testing.

2.2.1.1 HPSI System Description

The HPSI system, the low pressure safety-injection (LPSI) system, and the CS system were the subsystems of the emergency core cooling system (ECCS). The HPSI system consisted of three pumps and associated valves, instrumentation, and piping. One pump was normally operating as a charging pump, a second pump was aligned for standby operation, and the third pump was available as a spare. Upon a safety injection actuation signal (SIAS), ECCS pump suction would be automatically aligned to the refueling water storage tank (RWST). Following injection of approximately 200,000 gallons from the RWST, the ECCS would go into the recirculation phase, the HPSI system would realign to take suction from the discharge of the CS pumps, the CS pumps would take suction from the containment sump, and the LPSI pumps would be stopped.

2.2.1.2 Flow Testing

The HPSI system showed little-to-no margin in performance, particularly when operating at maximum flow conditions. The operating point for the HPSI pumps under these conditions was beyond the design information supplied by the pump manufacturer. The acceptability of the operation of these pumps under these conditions was established by licensee tests. These tests may have shown some degree of cavitation and an uncertain, but likely very small, margin. These limiting conditions would exist only in the low probability event of a large break LOCA.

The HPSI system was set up to operate under maximum flow conditions (approximately 800 gpm) at an operating point approximately 60 gpm beyond maximum flow on the pump curve provided by the pump manufacturer. Flow and net positive suction head (NPSH) data from the pump manufacturer were not available for this operating point. The licensee based the acceptability of the system on testing done on site in 1972 and 1993. The ISA team reviewed the results of these tests in detail and concluded that, although in the engineering judgment of both the ISA team and the licensee that the HPSI system was operable, the tests lacked rigor.

Preoperational HPSI pump runout tests were conducted in July 1972, and flow values were recorded up to 805 gpm with limited documentation of pump conditions and system lineup. However, the corresponding RWST tank and temperature were approximately 70,000 gallons and 105° F, and the tests were run after the HPSI flow to the three loops was balanced. The licensee later changed the minimum RWST level prior to sump recirculation to approximately 100,000 gallons, resulting in several additional feet of NPSH available to the pumps.

Additional HPSI pump testing at high flow conditions was done in 1993 following adjustments performed on the loop throttle valves. Regarding this testing, NRC Inspection Report 50-309/93-22, dated October 25, 1993, stated,

> During a dynamic test of motor operated valve (MOV) HSI-M-41, what appeared to be runout conditions were observed at high pressure safety injection (HPSI) Pump P-14A. The pump was noisy and with a flow measured at 796 gpm (not including the recirculation flow) the pressure was less than 390 psig. Upon further testing, the pump noise was still present when total flow was 800 gpm. While pump vibration and temperature remained normal, the licensee was unable to determine that initial pump cavitation was not occurring.

On the basis of the concerns of the ISA team regarding these tests (adequacy of documentation and instrumentation) and in order to provide additional assurance of the proper operation of the system, the licensee plans a future test of the HPSI pumps in a technically rigorous manner to fully demonstrate the available margin.

2.2.1.3 Throttle Valve Settings

HPSI flow control into the reactor coolant system (RCS) was controlled by three throttle valves per train that were set with a tolerance that may be too high. The ISA team was concerned with the critical nature of the setup of these throttle valves because unintended variations of as little as 20 gpm could result in some cavitation, if flow was too high, or not meeting design flow values assumed in the LOCA analysis, if flow was too low.

The position of the HPSI throttle valves (3-inch globe valves) was being controlled by the licensee within a tolerance of ± 1/16 inch based on full flow testing done in 1993. During this testing, the throttle position of these valves was established and mechanical stops were set. The licensee stated that tolerance on the position of these valves was based on using a ruler to measure how far the stem moved. In 1994 the licensee began to use a digital micrometer that measured stem position of these valves to within .001 inch.

The licensee did not have specific test data to evaluate the impact of this tolerance or a specific coefficient of flow (Cv) value for the throttle valves that could be used to calculate the impact of the tolerances on HPSI delivery flow. Estimates using a licensee supplied Cv that may be typical for this type of valve concluded that this tolerance band could cause a flow variation of more than 20 gpm per valve.

Actual flow through the HPSI throttle valves was measured each refueling cycle by Procedure 3.1.15.3, "ECCS Operational Pump Flow and Check Valve Testing." Flow measurements to each loop were measured and evaluated to ensure an adequate amount of total flow to the RCS and to ensure an acceptable flow distribution among the three loop injection points to account for the possibility that, in an accident, the flow through one loop may bypass the core by going out the break. Although this test could not be used to definitively evaluate the settings of the throttle valves under full flow conditions (essentially no reactor coolant system back pressure), it did provide a realistic appraisal of system performance and would indicate a gross mis-adjustment of the throttle valve settings. The ISA team reviewed the results of the last performance of this test, as it pertained to the HPSI system, in November 1995, and found them acceptable.

The planned HPSI flow testing to verify pump conditions at high flow will also enable the licensee to reset the position of these valves using a more precise tolerance to ensure that required flow is met and runout conditions are not exceeded. The licensee plans to include the resetting of these valves to a more precise tolerance as part of that flow testing.

2.2.1.4 CS System Support to the HPSI System

The ability of the CS system to provide a reliable supply of water during the recirculation phase of a LOCA was not adequately demonstrated for operation at power levels above 2440 MWt due to CS pump cavitational concerns. These

conditions would exist only in the low probability event of a large break LOCA.

Maine Yankee was licensed to pre-1971 general design criteria (GDC) in Appendix A to 10 CFR Part 50. These criteria were provided in Appendix A of the Maine Yankee FSAR. FSAR Criterion 44 provided requirements for ECCS and stated in part, "The performance of each emergency core cooling system shall be evaluated conservatively in each area of uncertainty." The ISA team reviewed current and historical design calculations to evaluate if net positive suction head available ($NPSH_A$) for the CS pumps during the recirculation phase was derived with the appropriate conservatism required by Criterion 44.

The licensee asserted, and the ISA team found no evidence to contradict, that Maine Yankee was not committed to the requirements of Regulatory Guide 1.1, formerly Safety Guide 1, dated November 2, 1970[6], which stated in part that "Emergency core cooling and containment heat removal systems should be designed so that adequate NPSH is provided to system pumps assuming maximum expected temperatures of pump fluids and no increase in containment pressure from that present prior to postulated loss of coolant accidents." The licensee assumed a less conservative CS pump NPSH, taking credit for accident induced containment pressure to demonstrate that $NPSH_A$ was greater than or equal to the net positive suction head required ($NPSH_R$).

The original NPSH calculation (MYC-272, Revision 2,"NPSH Study, Containment Spray Pumps"), assumed a sump temperature of 190 °F and zero containment over-pressure, although the maximum sump temperature was predicted to be significantly in excess of 212 °F. The licensee recognized the need to improve the quality of this analysis and began reanalyzing CS pump NPSH in 1995.

The current design basis NPSH calculation (MYC-1804, Revision 0, "Containment Spray Pump NPSH") established a time-dependent correlation between the $NPSH_A$ and $NPSH_R$ based on transient LOCA containment pressure and temperatures. This calculation showed an $NPSH_R$ of 15.3 feet and a positive margin of NPSH of less than 1 foot. A very sophisticated multi-node RELAP/MOD3 model was used to calculate blowdown mass and energy to the containment. A very simple one node code (CONTEMPT-LT28) used this information as an input to calculate the containment pressure and sump temperature required for determining $NPSH_A$. This analysis also assumed an initial power level of 2700 MWt. During the ISA the licensee provided information from the pump manufacturer which indicated that the pumps in question could be expected to operate for up to 15 minutes without damage with an $NPSH_A$ of 11.4 feet at 3700-3900 gpm.

The following weaknesses were identified in this analysis.

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[6]"Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps"

(1) The precision of the analytic technique and the sensitivity of the analysis to containment sump temperature.

The team's evaluation of the results ($NPSH_A$ values) indicated that a change in sump temperature of only 1 °F would change the result by about 1 foot. $NPSH_A$ was calculated based on iteration between the two computer codes described above, that have an unknown degree of uncertainty for this type of analysis. In particular, CONTEMPT-LT28 has options intended to bound the extent of mixing between the containment atmosphere and the break effluent, since a single node cannot address this phenomenon. Also, no validation for this type of analysis was presented. Given the uncertainty in the codes, the iteration scheme, and the sensitivity of the final product of this calculation, the ISA team questioned the validity of this calculational approach and the specific modeling assumptions used.

(2) Incorrect calculation of bounding CS pump suction head losses.

The suction pipe friction losses were developed for pump P-61A in calculation MYC-272, Revision 4, "CS Pump Suction Losses During RAS." Assumption two of this calculation stated that the suction piping arrangements to pumps P-61S and P-61B were virtually identical to pump P-61A. Therefore, this calculation was assumed to bound the worst-case condition for all three pumps. The ISA team determined that the suction piping arrangement for pump P-61S would result in higher suction piping frictional losses than those calculated for pump P-61A. As a result of the ISA team's concern, the licensee performed an evaluation that confirmed an increase of suction pipe friction losses from 4.5 feet to approximately 5.3 feet.

(3) Use of a hot fluid temperature correction factor.

The licensee took credit for reduction of the $NPSH_R$ requirements due to the increased sump temperature. This phenomenon was described in the Hydraulic Institute Standards. The ISA team viewed the use of the $NPSH_R$ correction for this application as an example of a non-conservative assumption.

The Hydraulic Institute Standards (currently American National Standard for Centrifugal Pumps, ANSI/HI 1.1-1.5-1994) provided limitations and precautions for use of the $NPSH_R$ temperature reduction, including considerations of entrained air or other gases present in the liquid and consideration of the susceptibility of the suction system to transient changes in temperature and absolute pressure. The ISA team considered that both of these limitations merited consideration because the sump water may not be sufficiently deareated and the CS pump would be undergoing a significant temperature transient near the time of minimum availability of NPSH. However, the calculation was silent on applicability of these limitations.

Following the assessment, the licensee conducted additional analysis to support plant operation at up to 2440 MWt. After reviewing this information, the ISA team concluded that it was appropriate to consider these pumps operable at power levels up to 2440 MWt.

2.2.2 Service Water/Component Cooling Water

The ISA team concluded that the support systems, service water and component cooling water, designed to remove decay heat and heat generated by individual components were capable of performing their design function up to the presently authorized power of 2440 MWt.

2.2.2.1 System Description

The service water (SW) system was comprised of four SW pumps (housed in the circulating water pump house), four heat exchangers (two each for primary component cooling water (PCCW) and secondary component cooling water (SCCW), and interconnecting piping and valves. The PCCW and SCCW heat exchangers consisted of two pairs of heat exchangers, an older and smaller one and a newer and relatively larger one (by approximately 20 percent), in each pair. The newer heat exchangers had titanium tubes and the older one had copper-nickel tubes. The SW system provided the ultimate heat sink for cooling of plant equipment. The system provided safety and non-safety functions by pumping seawater through the PCCW and SCCW heat exchangers.

The PCCW and SCCW systems performed an integrated function with the service water system in cooling plant equipment and removing decay heat. Each subsystem consisted of two pumps, the heat exchangers described above, and a flow distribution piping network. These subsystems absorbed heat from individual component coolers and from the residual heat removal (RHR) heat exchangers (one per train), which represented the major post-accident heat load in removal of heat from the containment building.

2.2.2.2 Availability of Seawater Flow Into the Service Water Intake Structure

A bottom contour map based on a 1994 survey of the area near the circulating water pump house showed relatively open access to the Back River and ultimately to the Atlantic Ocean. Therefore, an ample water supply was assured to the SW system.

2.2.2.3 Service Water Pump NPSH

The service water pumps had sufficient margin of submergence over the range of operating tide levels.

In the installed configuration, the pump inlet flanges were at an elevation of -14 feet 6 inches, and all pumps were shop tested to a water level of 2 feet 6 inches above the pump inlet. The water level at minimum submergence would therefore be at elevation -12 feet. A review of tidal records from 1989 to present (except 1995 when the plant was not operating) showed that elevation -7 feet (with small variations) was the low tide level.

2.2.2.4 Circulating Water Pump House Flooding

Adequate provisions were in place to mitigate the impact of flooding in the circulating water pump house. These provisions included level alarms, header

pressure switches that provided information if the headers failed, check valves to prevent drain back, and a 7-1/2 feet seismic wall that separated the circulating water pumps from flooding the SW space. In the event of flooding, the operators had sufficient information and time to locate the problem and isolate it before damaging the SW pump motors.

2.2.2.5 Residual Heat Removal (RHR) Heat Exchanger Thermal Transient

The ISA team found that, with the plant operating at 2700 MWt, the most limiting design-basis thermal transient, shifting to recirculation during a LOCA, on the RHR heat exchangers was beyond their design specification and had not been analyzed. The consideration of this thermal transient, apparently not explicitly addressed in conjunction with the power upgrade to 2700 MWt, was considered a weakness. Once again, these limiting conditions would exist only in the low probability event of a large break LOCA.

The maximum heat transfer rate, according to the RHR heat exchanger vendor, was approximately 120 MBtu/hr during a transient of 10 seconds; the heat exchanger could sustain 50 cycles of this transient. The power upgrade to 2700 MWt increased the maximum containment sump temperature to 255 °F, which resulted in a LOCA heat transfer rate of 137 MBtu/hr (calculation MYC-1742, Revision 1). A fatigue analysis of the heat exchangers at the higher thermal threshold was not performed; therefore some assurance was needed that the alternating stresses for the various subassemblies of the heat exchanger would not exceed their limits.

As a result of the ISA team's inquiry, the licensee investigated the impact of the higher thermal threshold. The original transient analysis calculation was no longer available. However, the vendor was able to provide a stress report for a heat exchanger of similar design and materials. The ISA team reviewed this information and concluded that these heat exchangers could be considered operable at the higher thermal values resulting from plant operation at 2700 MWt.

2.2.2.6 SW and PCCW/SCCW Integrated Operation

Calculations demonstrating the design margin of the SW, SCCW, and PCCW systems (PCCW and SCCW will be referred to as the component cooling water (CCW) systems) showed essentially no margin for the CCW systems in their ability to perform their safety-related functions. The component inlet temperature of the CCW system loads was set at 118 °F, which appeared to be the maximum temperature for assuring adequate heat removal from system loads under accident conditions. By the use of calculations, all of the available margin was transferred to the SW system to optimize operational flexibility. The limiting conditions of this analysis would be significant only in the low probability event of a large break LOCA.

The ISA team was concerned with this approach to operation of the SW and CCW systems because of the lack of margin in the CCW supporting calculations and the material condition of the system (heat exchanger bypass valves). Despite these non-conservatisms, the ISA team concluded that it was appropriate to

consider the PCCW/SCCW systems operable at power levels up to 2440 MWt. The ISA team was unable to conclude, and the licensee did not demonstrate, that these heat removal systems would perform adequately under design-basis accident conditions originating from a power level of 2700 MWt.

On the basis of this integrated heat removal analysis, an engineering directive had been provided to ensure the SW system would be operated within certain limits. However, the operating limitations provided in the engineering directive were not bounded by the licensing commitments. Section 9.4.1 of the FSAR stated, "The component cooling water system heat balance was performed in 1990 ... demonstrating adequate capacity for design basis post-LOCA conditions assuming a service water inlet temperature of 80 °F for CCW heat exchangers E-4B and E-5A, and 90 °F for CCW heat exchangers E-4A and E-5B." The engineering directive restricted the maximum SW temperature to 70.2 °F for E-4B and E-5A (the older Cu-Ni units), and 78.5 °F for E-4A and E-5B (the newer titanium units). On the basis of the licensee's analysis, the CCW systems would not support plant operation up to the SW temperature values in the FSAR.

Integrated operation of SW and PCCW/SCCW was non-conservatively analyzed due to:

1. CCW and RHR Heat Exchanger Fouling and Testing

Fouling factors used for the CCW and RHR heat exchangers were not appropriately conservative given the lack of reliable testing done to confirm the assumed values.

The ISA team's review of heat exchanger test results and test practices identified that the test program was still being developed, and there was not enough reliable test results to support use of the fouling values used in the licensee's design calculations.

The ISA team had the following specific concerns with the licensee's heat exchanger testing program:

(a) Instrument uncertainty was not accounted for in determining the fouling values.

(b) The installed locations for the flow measuring devices were less than optimum to assure accuracy, and the flow measuring devices were not calibrated for their specific application or adjusted for the actual pipe wall thickness.

(c) Heat exchanger tubes were cleaned on a periodic basis; however, there was no requirement to do performance testing just before the heat exchanger cleaning, thus the maximum fouling value was not being monitored.

(d) The lack of surface mounted thermocouples made the measured temperatures susceptible to potential streaming.

2. Maximum CCW Heat Load

The ISA team's review of calculation MYC-1742, Revision 1, found that the CCW heat loads were modeled as one major load (RHR) and one auxiliary load that represented all other CCW loads. The RHR heat exchanger load was based on a maximum containment sump temperature, 255 °F, as determined in calculation MYC-1740, Revision 1. The remaining loads were lumped as a single 10 Mbtu/hr load. This value was developed as a sum of the emergency diesel generator (EDG) load, control room chiller, and other unidentified loads.

The ISA team questioned the basis for the 10 Mbtu/hr value, since in the case of the PCCW system, the heat load included the spent fuel pool (SFP) heat exchanger, which had a design load of 9 Mbtu/hr (prior to re-racking), and each emergency diesel heat exchanger, which had a load estimated at 5 Mbtu/hr. For the SFP load, the licensee assumed that the total load on the PCCW heat exchanger would not exceed the analyzed valve based on an assumption of initial SFP temperature of 110° F.

3. Flow Diversion

Temperature control for the PCCW and SCCW systems was accomplished by adjustment of the bypass flow around the heat exchangers (shell side). There was only one air operator per system that operated both the inlet valve and the bypass valve. The calculations assumed that during a design-basis accident the bypass valve would be fully closed and the inlet valve would be fully open, thus maximizing flow through the heat exchanger. If the bypass valves did not go to their safety related positions, the heat transfer capability of the heat exchangers could be significantly degraded.

In 1995 the licensee discovered that the CCW heat exchanger bypass valve, PCC-T-20, was open about 11° following an attempt to align it to its safety related position, closed. At the time, Maine Yankee was in an outage and an immediate operability determination was not required; however, the reportability determination had not yet been completed at the time of the ISA.

The ISA team found no calibration procedures for these valves, the controllers were not of the "fail safe" design, no procedures were found that tested ability of these valves to perform their safety related function, and the maintenance history of these valves identified 11 completed maintenance work orders (WOs) for these valves in the last five years. On December 26, 1995, maintenance work order (WO) 95-3194 was initiated which identified that the linkage between CCW heat exchanger bypass and inlet valves, PCC-T-20 and PCC-T-19, was misaligned. This WO was open at the time of assessment and scheduled for completion during the 1997 refueling outage. WO 93-04459-00, completed on January 1, 1996, (PCCW), and WO 96-01785-00, completed August 9, 1996, (SCCW), did not demonstrate whether these valves would perform their safety related function. WO 96-01785-00 stated that a positioner failure appeared to be similar to PCC-T-20 and recommended to "watch as loads get added". WO 93-04459-00 had a recommendation to "rebuild/recal entire controller" in the event that controller continued to malfunction.

On the basis of the ISA team's concerns, the licensee performed a test on the PCCW temperature control valve after the team left the site. This test was reported as successfully demonstrating the operation of this valve.

2.3 Electrical and Instrument and Controls

The team found that the capability of the electrical system and instrument and control equipment to be generally robust and capable of performing their design function. Significant exceptions were noted with environmental qualification of components and ventilation systems.

2.3.1 115 kV Offsite Power Lines

The 115 kV offsite power lines were not independently capable of supplying the plant auxiliary power system under certain conditions. In FSAR Section 8.2.3, the licensee stated that either of the incoming lines is independently capable of supplying the plant auxiliary power system. In FSAR Criterion 39, "Emergency Power for Engineered Safeguard Features" (FSAR, Vol III, Appendix A), the licensee stated, "alternate power systems shall be provided and designed with adequate independence, redundancy, and capacity to permit functioning required of engineered safety features. As a minimum, the onsite and offsite system shall each independently provide this capability assuming a single failure of a single active component in each power system."

The station had two incoming 115 kV lines, and the main generator was connected to a 345 kV line; all were interconnected to the New England area transmission network. The main generator was connected to the 345 kV switchyard. Startup and standby (reserve) offsite power was provided by the 115 kV switchyard (which used two incoming lines, Surowiec and Mason) through reserve station service transformers X14 and X16. Under heavy loading conditions, a capacitor bank was used to compensate for and reduce the reactive voltage drop on the Surowiec line.

In 1995 Central Maine Power (CMP) completed an update of its studies of the 115 kV system to verify that the system remained capable of supporting Maine Yankee licensing requirements. As a result of the CMP studies, the licensee found that the electrical system analyses in calculation MYC-430, Revision 3, "Auxiliary Power System Voltage Study," failed to consider the effect of a motor-driven main feedwater pump (MDFW) automatic start following fast transfer of plant loads to the 115 kV offsite reserve power system.

The CMP voltage study for the "full" 115 kV system, both Surowiec (Section 69) and Mason (Section 207) lines, indicated that the system could support fast transfer of plant loads and subsequent start of a MDFW pump. However, the voltage study for the Surowiec line only (Section 69) indicated that the 115 kV system was inadequate for the MDFW pump start. The study confirmed that the Surowiec line voltage would not recover (after a fast transfer, a safety-injection actuation signal, and subsequent MDFW pump auto-start) within the allotted 5-second reset time interval of the degraded grid undervoltage relay to prevent offsite reserve power from being disconnected and automatic start and loading of the EDGs. The ISA team concluded that this situation (i.e., the limited capability of the Surowiec line) was contrary to the design

and licensing-basis presented in the FSAR which stated that either of the 115 kV lines was independently capable of supplying the plant auxiliary power system.

As stated in a letter to the NRC dated July 19, 1996, the licensee became aware of this issue as a result of a 1995 CMP update of its studies of the 115 kV system. In response to the ISA team's concerns in this area, the licensee stated that the 345 kV offsite system would serve as an alternate source of reserve power. The 345 kV system can be back-fed from the main transformer through the normal station service transformers to provide station power to the onsite 4160 Volt auxiliary power system. The licensee considered this circuit to be a delayed access circuit which could be completed in approximately six hours with disconnection of the main generator links. The Maine Yankee Technical Specifications, Section 3.12, "Station Service Power," required one 115 kV incoming line to be in service when the plant was at power. Therefore, a Technical Specification Interpretation dated January 12, 1996, was initiated to require that when 115 kV was in standby or was supplying plant loads, and either MDFW pump was in the automatic mode, then the Surowiec line (Section 69) was considered inoperable.

The ISA team did not consider the licensee's position that the 345 kV system back-feed operation, completed within six hours, was an acceptable basis for compliance with the FSAR and Maine Yankee Design Criterion 39. However, the ISA team considered this situation to be of low safety significance considering the historical stability of the grid, the existence of two independent reserve power transformers (X14 and X16), and the limited conditions (heavy loading and automatic start of MDFW pump) under which the Suroweic line would be unavailable.

2.3.2 Degraded Grid Undervoltage Relay Calibration Tolerance Band

The ISA team found that the calibration tolerance band for the degraded grid undervoltage relays may result in a setting that could cause a premature transfer of loads from offsite power to the emergency diesel generators (EDGs) following a LOCA. As a result of recently updated CMP voltage studies, the licensee was in the process of revising the electrical system analyses in calculation MYC-430 (Auxiliary Power System Voltage Study, Revision 3, May 14, 1990). As a result of these analyses, a vulnerability was found in the onsite auxiliary power system because the upper limit of the calibration tolerance band specified for the reset setpoint of the degraded grid undervoltage relays was set too high (95.5 percent of rated bus Voltage.) Under worst-case conditions these relays set at the specified upper limit of the tolerance band could cause premature transfer of loads from the 115 kV offsite reserve power system to the EDGs. This could have created a situation that would be contrary to FSAR Section 8.2.3, which required the offsite reserve power system to be capable of supplying the plant auxiliary power system.

In response to this issue the licensee stated the following: (1) A CMP grid load of 1,366 MW assumed in the full system base case is unlikely; however, Maine Yankee would again notify CMP to bring the Maine Yankee capacitor bank and Surowiec Transformer Auto Boost into service at grid loads greater than

1,300 MW. (2) CMP would be asked to perform a system analysis based on a grid loading of 1,300 MW and the results would be used to verify an adequate system voltage to reset the degraded grid undervoltage relay. (3) The full system base case would be eliminated from calculation MYC-430 and replaced with a new case which is based on the grid at a 1,300 MW load. (4) The calibration tolerance band of the degraded grid undervoltage relay would be reduced. The ISA team agreed with the licensee that the potential for the as-found settings of these relays to cause a premature transfer of loads to the EDGs was unlikely and considered their planned actions acceptable.

2.3.3 Electrical Protection, Coordination, and Cable Selection

The ISA team reviewed the specifications, drawings, calculations, protection scheme, cable data, motor data, protective relay setting criteria, relay settings, calibration records, and coordination for the 4,160 Volt ac and 480 Volt ac emergency buses, with particular emphasis on motor and bus protection associated with the HPSI, EFW and SW systems. In addition, selected motor and MOV feeder cables were reviewed for electrical equipment loading, cable sizing, cable routing, tray and conduit fill, and ampacity derating for these systems. Overall, the ISA team found that electrical protection and coordination calculations were good, protective relay setting criteria was consistent with industry standards and practice, protective relay calibration records were good, cable sizing was robust, ampacity derating was appropriate, and tray and conduit fill was acceptable. However, some minor discrepancies and errors were found (see Section 2.3.6).

2.3.4 125 Volt dc Vital Station Batteries

The ISA team concluded that the battery capacity was robust, and that all vital station batteries had a capacity greater than 110 percent of the needed capacity.

2.3.5 Emergency Diesel Generator Electrical Loading

Although the EDGs were assessed non-conservatively, their capacity was sufficient.

The onsite emergency ac power system consisted of two independent and redundant 4,160 Volt, 2,850 kW (2,000 hr/yr rating) EDGs. The ISA team reviewed calculation MYC-107, "Emergency Diesel Generator Loading," Revision 4, which evaluated the loading of equipment onto each EDG. The ISA team found that calculation MYC-107 was not well documented, EDG loading was assessed non-conservatively because all required loads were not included in the calculation, and the loading profile was inconsistent with FSAR and design requirements. The ISA team concluded, however, that the EDGs were able to start and carry all required loads, including the additional loads found by the ISA team and not included in the calculation. The ISA team noted the following problems with the evaluation of EDG loading in calculation MYC-107:

(1) Cable power losses in the 4-kV and 480 Volt ac systems were not incorporated into the calculation. This additional load was estimated to be in the range of 30 to 40 kW.

(2) The loading profile was inconsistent with FSAR and design requirements. On the basis of FSAR Section 8.3.2 and the elementary system drawings, CS pump P-61A and PCCW pump P-9A automatically start 10 seconds after closure of the EDG 1A circuit breakers when EDG 1A starts in response to a SIAS. Contrary to this, the EDG-1A loading profile in calculation MYC-107 showed these pumps loading at 20 seconds with EFW pump P-25C. In response, the licensee stated that FSAR Discrepancy 25 (June 19, 1996) was initiated to identify and resolve the discrepancy in the power demand for the loading steps; however, this specific problem was not noted in this document. The ISA team judged that this discrepancy would not have an adverse impact on the EDG operability.

(3) There was a lack of documentation in the calculation to support motor loads. This was a minor weakness in the calculation.

(4) Pump motor loading was non-conservative. LPSI pump loading in calculation MYC-107 was identified as 336 kW; however, the loading value at runout would be 364 kW. The EFW pump loading was also based on a nominal value of 378 kW rather than on the runout value of 441 kW.

(5) Control air compressor manual start, required by procedure ECA-0.2, "Loss of All ac Power Recovery, SI Required," was not incorporated into the calculation. The licensee stated that the additional electrical load would be a cycling load of 24.5 kW for an unloaded compressor and 71 kW for a loaded compressor.

(6) MOV replacements were not accounted for in the EDG loading calculation in that operators and motors for 14 MOVs were replaced under the MOV Upgrade Program, but the motor horsepower changes were not included in the electrical one-line drawings and tracked as required by Procedure 17-227, "Electrical Distribution System Load Tracking," Revision 1. Although the load changes were mostly a decrease of a few horsepower, this was an example of a weakness in configuration control.

In response to the ISA team's concerns in this area, the licensee prepared a preliminary revision to calculation MYC-107 which showed that the loading on EDG-1B (worst-case) increased from 2,629 kW to 2,842 kW (a 213 kW increase), still below the 2,000 hour/year rating limit of 2,850 kW.

2.3.6 Electrical Calculations

Despite the deficiencies noted with the EDG loading calculation and several other relatively minor weaknesses, electrical calculations were very detailed, comprehensive, and rigorous. Calculations prepared since 1993 were better documented and more sophisticated than earlier calculations.

However, the following additional calculational problems were noted:

(1) Incorrect motor data were used for setting the HPSI pump motor protective relays in calculation MYC-1559, in that the incorrect locked rotor current was used. The error was in the conservative direction and

motor protection was still maintained; therefore, this issue had no adverse impact on plant safety.

(2) Incorrect cable data were used in the coordination curve for the EFW pump P-25C motor in calculation MYC-1559. This error was in the conservative direction and motor protection was still maintained; therefore, this issue had no adverse impact on plant safety.

(3) Cable data and cable damage curves were omitted from calculation MYC-1063, "480 Volt Circuit Breaker Coordination," Revision 5, where curves did not identify the feeder cable size and did not incorporate the cable damage plot on the coordination curve to demonstrate that the cable was protected consistent with industry practice. The lack of cable data and cable damage plots had no adverse impact on plant safety because cable sizing was conservative.

2.3.7 Inadequacies in Ventilation Systems

Although the licensee had previously identified inadequacies in the ventilation systems used to support safety-related electrical equipment, the ISA team found additional significant inadequacies in the design of these ventilation systems.

2.3.7.1 Protected Switchgear Room Ventilation

Deficiencies were noted in the design of the protected switchgear room ventilation system. The licensee was aware of, and actively correcting, some of these deficiencies. As a result of the ISA team's inquiries additional vulnerabilities were identified. The net effect of these recently identified problems could be significant, possibly contributing from 1 percent to up to 10 percent additional probability of core damage.

The battery and protected switchgear rooms were located in the turbine building and serviced by a safety-related ventilation system. The equipment for this ventilation system was located in the turbine building and consisted of motor-operated air supply and exhaust dampers, supply fan FN-31 (powered from train A 480 Volt emergency motor control center (MCC) 7A), a motor-operated recirculation damper, and exhaust fan FN-32 (powered from train B 480 Volt emergency MCC-8A). This ventilation system supported the operation of the plant's safety-related batteries, inverters, and MCCs. In FSAR Section 8.3.3, the licensee described the lack of redundancy for this ventilation system (single supply and single exhaust fans) and specified operator actions required to mitigate the consequences of a single fan failure.

As part of the Individual Plant Examination - External Events (IPEEE) effort, the licensee recently evaluated the turbine building spectrum of steam line breaks. It was recognized that following a high-energy line break (HELB), operator action may be required to manually ventilate the protected switchgear room. On the basis of calculations, assuming that the ventilation fans were not running, the licensee concluded that the steam ingress into the protected

switchgear room was not significant, and the high-temperature alarm in the room would signal operators to open doors and set up portable fans.

Despite the licensee's work to mitigate the effects of a potential HELB in the turbine building, the licensee did not fully consider the impact of a LOCA or HELB event on the protected switchgear room ventilation system. The ISA team found that the licensee had no calculations or analyses which evaluated the consequences of a supply or exhaust fan failure coincident with a LOCA or HELB under worst-case electrical loading. Although the licensee had prepared calculation MYC-1570, "Protected Switchgear Room, Protected Cable Tray Room & Battery Rooms 1-4 Temperatures," Revision 0, to address the transient temperature in the safety-related electrical areas for various scenarios, the ISA team found that the calculation did not address various fan failure modes. Further, the ISA team found that no emergency power source was available to power portable fans during a design-basis event which may include loss of normal ac power. Therefore, the compensatory operator actions to open doors and set up portable fans described in the FSAR and the licensee's analyses were not technically supported.

The original licensing-basis assumption for HELB inside the turbine building was for a break of a very large steam line that would result in enough damage to the turbine building that the effects of the line break would be rapidly mitigated by the failure of the building walls. However, the licensee recently concluded that the limiting HELB event was a smaller size break that would leave the turbine building intact, causing the harmful effects of the steam to be felt for a longer period of time. As a result of this finding by the licensee (before the ISA), compensatory measures were implemented to keep enough openings in the turbine building to mitigate the effects of a more limiting break.

In response to the ISA team's concerns, the licensee performed an additional analysis for calculation MYC-1570, taking into account all failure scenarios for the protected switchgear room ventilation system, including the scenario in which one fan (supply or exhaust) was assumed to fail. Air flow measurements for the ventilation system and switchgear room under various fan configurations were also taken. Based on the results of this analysis, the following actions were taken by the licensee:

(1) The supply and exhaust dampers were blocked open and the recirculation damper was blocked closed under Work Order 96-02589-00, "Reposition Dampers," Revision 1.

(2) Design Basis Screen (DBS) 96-006 ("Turbine Building MSLB Environment," Revision 3) was issued which concluded that the worst-case failure mode would be failure of a supply fan while the exhaust fan continued to run, resulting in the ingress of steam into the protected switchgear room which would be unacceptable. The heat load from switchgear and equipment was reduced by approximately 30 percent to eliminate unnecessary conservatism. The results of revised calculation MYC-1570 showed that the HELB scenario bounded the LOCA scenario and resulted in a heat buildup in the switchgear room which would require an operator to

block open doors and set up portable fans within 15 to 30 minutes following the event to limit room temperatures to 135 °F.

(3) An emergency stop switch was installed in the control room under Work Order 96-02824-00 to allow an operator to trip the exhaust fan to limit ingress of steam into the switchgear room during a HELB event in the turbine building.

(4) A temporary change was made to Procedure AOP-2-7, "Excess Steam Demand," Revision 16, to provide guidance to the operator for establishing protected switchgear room cooling following a turbine building HELB event.

(5) A 350-foot power cord was provided to allow operators to plug into an EDG-backed power source (120-V ac vital power) for portable ventilation fans. A long-term, permanent modification was intended to install receptacles in the protected switchgear room which would be powered from EDG-backed emergency buses MCC-7A and MCC-8A.

(6) The current HELB evaluation covered summer conditions only; the licensee was formulating plans to resolve this issue for winter conditions.

2.3.7.2 Spray Building Ventilation Deficiencies

Deficiencies were noted in the design of the spray building ventilation system. The licensee was aware of, and actively correcting, one of these deficiencies. The ISA team identified a separate deficiency that had the potential to effect the performance of the CS and LPSI systems.

The spray building houses the CS pumps and LPSI pumps. The ventilation system for this building consisted of a supply unit (HV-7), two safety-related exhaust fans (FN-44A and FN-44B), and associated dampers and ducts. HV-7 comprised a heating coil, fan, and filter.

The licensee had experienced occasions in which ventilation flow through HV-7 had been restricted due to ice buildup on the external surface of the unit in the winter months and from leakage from the heating coil causing ice to build up on the filter portion of this unit. Such situations were significant because there was a potential to impact the CS and LPSI pumps, which required adequate ventilation (removal of motor heat) in order to continue to run. The licensee recognized this problem and was in the process of implementing a design change to reconfigure the HV-7 supply unit to solve the existing design problems. The ISA team reviewed the licensee's plans to improve this design and found them acceptable.

As part of the review of this issue, the ISA team looked at the integrated operation of the spray building ventilation system and found that there were pneumatically positioned dampers (VP-A-56 and VP-A-57) on the suction side of the safety-related exhaust fans. Since the damper's air supply was non-safety-related, and considering the design of the dampers, there would be a reasonable potential for the dampers to close under accident conditions,

thereby rendering this safety-related ventilation system inoperable. On the basis of this concern, the licensee prepared DBS 96-051 and mechanically blocked open dampers VP-A-56 and VP-A-57.

After the ISA team identified this issue, the licensee informed the ISA team that the desirability of blocking open these dampers had been raised in 1991 by a staff person from YAEC in a memorandum dated February 20, 1991, with the subject, "Minimum Ventilation Requirements for the Containment Spray Pump Area." This memorandum contained a specific recommendation to block open dampers VP-A-56 and VP-A-57 because, "If the controller fails, it could cause the inlet vanes for both fans to close, causing a reduction in the output of the system." The ISA team found no evidence that this issue had been entered into a corrective action system or was being tracked by the licensee. This was an example of the licensee's failure to take appropriate action to address a plant problem.

Although the plans and progress to resolve the problems with HV-7 were considered positive, the ISA team considered the licensee's performance weak in regard to the lack of followup of the identification of the damper concerns from 1991 and also weak in that the recent focus on the problems with this ventilation system did not result in identifying a vulnerability with dampers VP-A-56 and VP-A-57.

2.3.8 Procedure for Cross-Connecting DC Buses

Plant Procedure 1-22-2 " AC and DC vital Bus Operation," allowed cross-connecting redundant 125-Volt dc vital buses for up to 72 hours during plant operation, contrary to FSAR Appendix A, Criterion 39, "Emergency Power for Engineered Safety Features," which stated, "Alternate power systems shall be provided and designed with adequate independency, redundancy and capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite and the offsite power system shall each, independently provide this capacity assuming a failure of a single active component in each power system."

The ISA team found no instance when these buses had been cross-connected and, in response to the ISA team's concerns, the licensee stated that no occurrences of cross-connecting 125-Volt dc vital buses were documented after 1982, but cross-connection could have occurred before this period.

The licensee stated that this procedure was intended to be used only in limited conditions with due consideration given to overall plant risk. However, as a result of discussions with the ISA team, Procedure 1-22-2 would be revised to limit cross-tieing of dc buses to Condition 5 or lower (i.e., plant not at power) for maintenance activities.

2.3.9 Environmental Qualification (EQ) Program

The ISA team found that the licensee was not meeting 10 CFR 50.49 requirements in that there were certain electrical components that were not qualified for their expected environment following a design basis event. There were concerns in three separate areas: submergence inside containment,

EQ/Regulatory Guide (RG) 1.97 instrument qualification, and backlog of EQ items. The ISA team also noted that there was no assigned staff engineer with primary responsibility in this area.

2.3.9.1 EQ Submergence

As a result of a concern by the ISA team about EQ component elevations being below submergence level, the licensee conducted a walkdown on July 24, 1996, of reactor containment that revealed 30 components outside of Maine Yankee's design basis. These components were found to be installed below the maximum submergence level of 1.7 feet inside containment and were not environmentally qualified for the installed location. The EQ Program worksheets and EQ database did not reflect the actual component elevations.

The EQ components affected were distributed into three groups: containment isolation valve position indication; all channels of steam generator level (wide range and narrow range) indication; and primary inventory trend system level indication. Submergence levels for the EQ components ranged from 1/2 inch to 31 1/4 inches below the maximum submergence level of 1.7 feet. The EQ submergence problem was reported to the NRC in licensee event report (LER) 96-026 dated August 22, 1996.

The licensee's EQ submittal dated October 31, 1980, and the NRC's safety evaluation report (SER) dated June 1, 1981, identified approximately seven plant components that were below the submergence level that needed to be removed or replaced to meet the EQ rule. As a result of the ISA team's inquiry, the licensee identified 30 components below the submergence level. Several of these components, such as HCV-257, HCV-271, and TV-3501, were the same components that were identified as below the submergence level in the licensee's 1980 submittal and the NRC's SER.

2.3.9.2 EQ/RG 1.97 Instrument Qualification

The assumptions used to established EQ requirements for emergency feedwater (EFW) flow instrumentation were found by the ISA team to be inconsistent with Emergency Operating Procedure (EOP) E-1, "Loss of Primary or Secondary Coolant," operational requirements in that, under design-basis accident conditions, the use of the EFW flow instruments may not have been available.

The EQ worksheets for EFW flow transmitters FIT-1201A, FIT-1201B and FIT-1201C stated that EQ for these instruments during LOCA conditions was not required per YAEC memorandum, MYP 93-0293, Revision 2; however, EOP E-1, Step 3.a, required the operator to ensure minimum FW flow for decay heat removal. In MYP 93-0293, the licensee stated that steam generator level was an acceptable means of verification of EFW flow when referenced in the EOPs. However, without qualified EFW flow transmitters, EOP E-1 requirements may not be able to be accomplished in those situations (large break LOCA) where minimum EFW flow is required to ensure heat sink availability. During these situations, EFW flow instrumentation would be required until steam generator level exceeded the specified level limits.

Since the EFW flow transmitters would be exposed to a harsh radiation environment during a LOCA (MYP 93-0293), the EFW flow instrumentation may need to be environmentally qualified. The licensee stated that evaluation of this issue was under way as part of a revision to DBS 96-41. This revision would add an action item to provide a detailed review of the radiation dose at the instrument location. In addition, the licensee's RG 1.97 submittal and Regulatory Guide Source Document, "Design and Qualification Criteria for Post Accident Monitoring Instrumentation," identified these transmitters as being appropriately EQ qualified with no deviations from NRC guidance. The licensee did not adequately categorize and identify the exceptions taken on the RG 1.97 data sheets.

2.3.9.3 Backlog Of EQ Items

There were other potentially significant EQ issues that remained open. The licensee had recently identified an expanded HELB concern in the turbine building that had the potential to impact safety related components in the turbine building.

2.4 FSAR Inconsistencies

Prior to the ISA team arrival on site, the licensee initiated a FSAR and Technical Specification review to identify discrepancies with the licensing basis. The licensee placed priority on reviewing those systems being reviewed by the ISA team. Over 100 issues were identified. The ISA team identified additional discrepancies which are discussed throughout the report. Many of these issues will require changes to the FSAR and 10 CFR 50.59 reviews since equipment and procedures at MYAPS have changed from that described in the FSAR.

2.4.1 Spent Fuel Pool Heat Exchanger Rating

The nameplate rating on the spent fuel pool (SFP) heat exchanger was not consistent with the design values in the FSAR.

Section 9.8.2 of the FSAR stated that the tube-side design of the heat exchanger (HX) was 225 °F and the nameplate stated that the tube-side rating of this HX was 200 °F. This discrepancy was noted in 1996 by an NRC review before the formation of the ISA team. The ISA team was concerned that the 200 °F HX tube rating could possibly prohibit the restoration of SFP cooling following a prolonged loss of SFP cooling and bulk boiling in the SFP. The licensee claimed a reasonable expectation that this HX could be used to restore normal cooling following bulk boiling and was tracking an action item to analyze by January 1, 1997, the capability of this HX to go to 225 °F. The ISA team considered the licensee's schedule reasonable because (1) the FSAR does not acknowledge restoration of normal cooling following bulk boiling, (2) the HX can be bypassed if necessary, and (3) there was an expectation for margin in the capability of this HX.

2.4.2 Atmospheric Steam Dump Rated For 2.5 Percent Power

The FSAR assumptions made regarding the response to a steam generator tube rupture (SGTR) were not realistic. In addition, the licensee assumed a capability of the atmospheric steam dump (ASD) of five percent power as part of its validation for EOPs. Subsequent licensee analysis of the steam generator tube rupture (SGTR) and inadequate core cooling (ICC) events revealed that the 2.5 percent value was acceptable for SGTR but not for ICC. The ICC event was beyond the design basis of the plant but was considered as part of the EOPs. (See Section 3.1.3.1)

FSAR, Section 14.12, stated, "The quantity of reactor coolant transported through the leak to the steam system is the same with or without offsite power. The primary to secondary leakage is assumed to be terminated within 30 minutes following the rupture." The ISA team considered that the additional complication of a loss of offsite power (LOOP) during an SGTR event would make it unlikely that the operators would be able to isolate the leak as quickly as would be the case with offsite power available. Without offsite power, the operators would lose their ability to vent steam to the main condenser, they would be limited in venting steam for cooldown through a single 2.5 percent capacity ASD valve. They would have to manually shut a valve locally in the vicinity of the steam generator relief valves before opening the ASD valve. The time to isolate the affected steam generator would be longer than stated in the FSAR.

In a letter dated July 1, 1996, to the NRC, the licensee committed to make physical changes to the atmospheric steam dump system to improve relieving capacity and reduce the isolation time of the affected SG.

3.0 ASSESSMENT OF OPERATIONAL SAFETY

The ISA team assessed Maine Yankee's performance in the areas of operations, maintenance and testing, and engineering by evaluating the programs in each of these areas and the licensee's implementation of these programs.

3.1 Operations Assessment

The ISA team assessed the ability of Maine Yankee to safely operate the plant in accordance with its licensing and design bases. The areas assessed included the licensee's programs for identifying and resolving problems, the quality of the licensee's operations, and the programs established to operate the plant. In addition, the radiation protection and the fire protection programs were reviewed. The team interviewed operators and managers, performed three days of continuous control room observations, conducted detailed walkdowns of safety systems, reviewed EOPs, observed simulator requalification training, and observed the implementation of programs used to operate the plant.

Overall, performance in the area of operations was very good. Strengths were noted in the areas of operator performance during routine and transient operating conditions; shift turnovers and pre-evolution briefs; use of risk information to ensure safe operations; and the involvement of management in day-to-day operations. Areas for improvement include reducing the number of operator workarounds and compensatory actions, log-keeping, and post trip reviews.

3.1.1 Problem Identification/Problem Resolution

The team assessed the programs used by Operations to identify and resolve problems in the plant. The team found that Operations was effective in identifying problems, but noted weaknesses with problem resolution.

3.1.1.1 Operator Workarounds and Compensatory Actions

Maine Yankee had several problems involving plant equipment, which created an additional burden on the operators during the plant shutdown and startup observed by the team. In addition, Maine Yankee had established several compensatory actions to address weaknesses in plant design. Some of these compensatory actions would require operators to take manual actions during a plant transient. Several workarounds and compensatory actions were longstanding issues or recurring problems which the licensee had not resolved.

During the performance of a plant shutdown on July 19 and 20, 1996, the team observed that the operators experienced several equipment problems which complicated the shutdown. These problems involved the trip of a motor-driven main feedwater (MDFW) pump following an attempted start, the slow response of the main feedwater pump recirculation valve when the pump was started, leakage past a main feedwater regulating valve bypass valve which required additional operator attention and actions, and the inability to operate the control element assemblies (CEAs) in the manual sequential mode due to a plant computer which was easily overloaded. The manual sequential mode problems

contributed to the operator's decision to manually trip the reactor from low power during the shutdown.

Maine Yankee had also implemented or proceduralized actions to compensate for weaknesses in the design of the plant. Compensatory actions were taken as a result of design vulnerabilities associated with ventilation systems for the safety-related battery rooms, switchgear rooms, emergency diesel generator (EDG) rooms, and the containment spray building; turbine building flooding concerns; the inability to remotely isolate a ruptured steam generator; a single, undersized, steam generator atmospheric steam dump (ASD) valve; and a degraded offsite power supply.

3.1.1.2 Control Room Staffing

In March 1996, following its review of NRC Information Notice (IN) 95-33, "Switchgear Fire and Partial Loss of Offsite Power at Waterford Generating Station Unit 3," and IN 95-48, "Results of Shift Staffing Study," Maine Yankee evaluated the ability of the operating crews, at their established manning levels, to respond to a plant fire similar to that experienced at Waterford Unit 3 in 1995. The team found that Maine Yankee's evaluation was thorough and that the licensee had identified weaknesses in (1) timely implementation of the emergency plan, (2) oversight by the Plant Shift Superintendent (PSS), (3) workload of the remaining Control Room Operators (CROs), and (4) normal Shift Technical Advisor (STA) oversight. Maine Yankee found that if a medical emergency occurred during a plant fire, the PSS, as the assigned medical emergency responder, and the Shift Operating Supervisor (SOS), as the assigned fire brigade leader, could both be summoned from the control room to perform these duties.

The team was concerned that the licensee had established conflicting procedural requirements that would be impossible to comply with in the event of fire coincident with a medical emergency. During this postulated event, the minimum staffing requirements required in the Technical Specifications would not be satisfied if the senior reactor operators responded as described in the licensee's administrative procedures. The team found that Maine Yankee has previously developed a comprehensive action plan to address the shift staffing issues which included: (1) using security personnel rather than the PSS as medical first responder, (2) using a second CRO as the fire brigade leader rather than the SOS, (3) providing an additional security guard for the fire brigade to replace an auxiliary operator, (4) enhancing the dose projection process, and (5) enhancing STA effectiveness. However, the team determined that Maine Yankee's schedule for implementing these corrective actions by the end of 1996 was not timely. The team also determined that the licensee missed an opportunity to identify and correct this vulnerability during its review of IN 91-77, "Shift Staffing at Nuclear Power Plants," which discussed Maine Yankee's response to a fire.

In response to the team's concerns, Maine Yankee reassigned the duties of the medical first responder to the security supervisor, thus removing these duties from the PSS. Additionally, the licensee planned to add a third licensed reactor operator to the control room staff and assigned the duties of the fire brigade leader to the reactor operator.

3.1.2 Quality Of Operations

3.1.2.1 Control Room Observations

The team observed the performance of operators during a 3 day period of sustained control room observations. During this time, operators performed a plant shutdown and cooldown to correct a design deficiency in the PCCW system. Operators performed well during the plant shutdown and cooldown. The team observed good command and control and good use of procedures. In addition, operators quickly identified and responded well to several equipment problems experienced during each activity.

The quality of communications used by operators during plant activities was good; however, the use of repeat-backs was inconsistent. In addition, control room alarms were seldom announced to the entire crew. The team observed similar weaknesses during simulator training sessions. Control room logs lacked detail and did not meet the guidance provided in Maine Yankee's administrative procedures. For example, operators did not log the starting time and stopping time of an EDG, equipment problems experienced during the plant shutdown, and the initiation of a manual reactor trip to shut down the reactor when problems were experienced with the CEA drive system. Observed shift turnovers and pre-evolution briefs were informative and provided operators with complete information about shift activities.

Auxiliary operator performance was identified as a strength. Team members accompanied auxiliary operators on their plant tours and found that they were knowledgeable, performed thorough rounds, took accurate logs, identified housekeeping deficiencies, and communicated well with operators in the control room. The utilization and performance of STAs was also a strength at Maine Yankee. The STAs were very experienced, had a good knowledge of plant operations, and were assigned a wide range of responsibilities, including conducting independent reviews of operability determinations and technical specification interpretations, making reportability determinations, and assisting the PSS with emergency plan implementation. The STAs also had a good understanding of probabilistic risk assessment which they used in performing on-line risk assessments and shutdown safety assessments. STAs updated these assessments as plant conditions changed and evaluated the effect of emergent maintenance on the assessment. STAs maintained the system unavailability log book and investigated unusual occurrences reported on their shift.

3.1.2.2 Safety Systems Walkdowns

The team performed a detailed walkdown of the accessible portions of the high-pressure safety injection (HPSI) and the service water (SW) systems to verify they were properly aligned. The systems were found to be properly aligned for emergency operation in accordance with the licensee's system operating procedures and plant drawings. Valves in the systems were labeled properly. Control room labeling of remotely operated valves was satisfactory with each remotely operated valve identified by number, noun name, and actuation signal (if applicable). Minor deficiencies, such as inoperable local valve position indicators and unidentified packing leaks, were identified by the ISA team and

the licensee entered these deficiencies into its work order system. Material condition deficiencies associated with the SW system are discussed in Section 3.2.1.5 of this report.

3.1.2.3 Management Oversight of Operations

Management oversight of plant operations was good. Managers were involved in the day-to-day operation of the plant and in the resolution of emergent problems. In addition, managers were actively involved in the operator requalification training program. Managers observed and evaluated crew performance during simulator training sessions, participated in the critique of crew performance, and reinforced their expectations for operator performance, including communications. Operations management met with crews during the training week to discuss operations issues. Management also conducted periodic assessments of the Operations Department as part of the Operations Performance Assessment Program. Control of overtime at Maine Yankee was also very good.

3.1.2.4 Risk Management

The use of Online Safety Assessments (OLSAs) and Shutdown Safety Assessments (SSAs) were strengths. The OLSA was used as a tool to assess the safety implications of scheduled maintenance, unexpected equipment failures, unscheduled maintenance, and for developing long-range maintenance schedules. The SSA provided a simplified indication of the level of plant safety when the plant was shut down. The STAs performed safety assessments each shift, or when major equipment was found inoperable or removed from service. These assessments were communicated throughout the organization and risk insights were apparent in the licensee's decision-making process.

The OLSA was based on key safety functions, PRA significance, external events, as well as operational and engineering judgment. Both the online and shutdown assessments used relatively simple, straight-forward methods to assess risk. OLSA was computer based and provided a plant score which was converted to a risk condition, i.e., green, yellow, orange, or red (in order of increasing risk). The OLSA program allowed calculation and control of accumulated risk during power operation by use of simple methods. SSAs were qualitative rather than quantitative and resulted in an overall risk condition, i.e., green, yellow, orange or red.

Management controls required approvals for intentional entry into the higher risk conditions and provided directions (such as immediate exit or development of contingency actions) for unplanned entry into higher risk states. Controls were established for exceeding calculated allowable times in higher risk states.

3.1.2.5 Operability Determinations

Maine Yankee's operability determinations were generally acceptable, although some weaknesses were noted. The team reviewed approximately 60 operability determinations performed in the past by Maine Yankee and found that the determinations were appropriate. However, while on site, the team noted that

the licensee made an incorrect operability determination associated with the performance of engineered safeguards feature relay testing.

On August 15, 1996, the licensee initiated SIC 96-18 to address inadequate testing of safety injection actuation system relays associated with the HPSI and the containment spray swing pumps. The PSS and the STA performed an operability determination and appropriately declared these pumps inoperable. On August 16, the licensee reported that the testing of HPSI pumps P-14A and 14B did not test all contacts in the pump start circuitry. On August 17, the Operations Manager issued a memorandum stating that these testing discrepancies did not render the ECCS pumps inoperable because the Technical Specifications (TSs) did not specifically require that all safety injection actuation system contacts associated with the pump start circuitry be tested.

The team found that this interpretation of the TS requirements was incorrect. The licensee inappropriately interpreted the relay tests required by TS Table 4.1-2, "Minimum Frequencies for Checks, Calibrations and Testing of Engineered Safeguards Systems Instrumentation Controls," were limited to verifying that the relays actuated properly. The licensee did not believe that TSs required contact actuation verification to confirm proper operation of the pump.

Following a conference call between Maine Yankee, NRC Region I and NRR personnel, the Operations Manager wrote a memorandum to the PSSs and STAs, which stated that if a safety-related logic circuit testing deficiency was identified, the associated components would be considered inoperable due to a failed surveillance and the appropriate TS would be entered.

3.1.2.6 Technical Specification Interpretations

The team reviewed 64 TS interpretations and found that the licensee appropriately used the interpretations to clarify specifications which lacked detail. However, 2 of the 64 interpretations reviewed inappropriately changed the intent of the applicable TS.

Technical Specification 5.5.B.9 required Maine Yankee's Nuclear Safety Audit and Review Committee (NSARC) to audit facility activities at frequencies defined by Sections a through k of this specification. The licensee had incorrectly applied the provisions of TS 4.0.A and incorporated a maximum allowable extension of +25 percent to the audit intervals. Maine Yankee indicated that it planned to cancel the interpretation.

TS 3.14 required two reactor coolant leakage detection systems of different operating principles to be operating, with one of the two systems sensitive to radioactivity in the containment, when the reactor was above two percent power. In a TS interpretation approved in 1985, Maine Yankee determined that leak detection systems sensitive to radioactivity were the containment gaseous radiation monitoring system, the containment air particulate detector radiation monitoring system, and daily containment grab samples. The team concluded that including a daily containment grab sample in this interpretation was a change to the TSs because this did not represent a continuously operating system. The licensee disagreed with the team.

At the conclusion of the assessment, the NRC was reviewing the appropriateness of this TS interpretation.

3.1.2.7 Post-Trip Reviews

The team reviewed five post-trip reviews (PTRs) from 1991 through 1996. The PTRs, in general, lacked rigor and completeness. The reviews did not have detailed event timelines, complete descriptions of the event, and operator responses could not be determined from the documentation. The PTRs did not contain a complete list of required and completed short-term corrective actions and planned long-term corrective actions. In addition, individual operator statements contained in the reviews generally did not contain sufficient detail to add value to the review. One PTR reviewed by the team indicated that data from the plant computer was unavailable because of problems associated with the plant computer and its inputs.

3.1.3 Programs And Procedures

3.1.3.1 Emergency Operating Procedures

Although the quality of the emergency operating procedures (EOPs) at Maine Yankee was good, some exceptions were noted. In general, procedures conformed to the writer's guide and gave clear guidance to the operators. However, Maine Yankee recently reported that EOPs may not be adequate to address an inadequate core cooling (ICC) event and a steam generator tube rupture (SGTR) under certain conditions.

In 1986 Maine Yankee identified the inability to recover from an ICC event due to the small relief capacity of the atmospheric steam dump valve. The ICC event is a low-probability event which requires a small-break loss-of-coolant accident coincident with a loss of condenser vacuum and loss of both trains of HPSI. Although the licensee planned to correct the problem, these plans were deferred and ultimately canceled in 1992. The licensee did not provide an explanation as to why the plans to increase the relief capacity were canceled.

In February 1996, the EOP coordinator re-discovered Maine Yankee' inability to recover from an ICC event and brought the issue to plant management's attention. Maine Yankee informed NRC on March 4, 1996, that the information contained in a previously submitted EOP generation package regarding the capacity of the atmospheric steam dump valve was incorrect.

In the Plant Root Cause Evaluation Report completed in July 1996, the licensee concluded that the ICC event was not a design-basis event and Maine Yankee was not required, nor did it commit, to have the capability to mitigate an ICC event. Nonetheless, the licensee did inform the team it intends to modify the plant to increase steam relief capacity. At the conclusion of the assessment, the NRC was reviewing Maine Yankee's commitments with respect to the ICC event.

In May 1996, Maine Yankee found that it may take more time to isolate a ruptured steam generator than was originally assumed in the SGTR EOP analyses. Specifically, in the event of a SGTR with a coincident loss of condenser

vacuum, the time to isolate the ruptured steam generator could exceed 20 minutes; this is 15 minutes longer than the analysis assumption of five minutes. This increase was identified when Maine Yankee found that, due to a harsh environment created by the lifting of the main steam safety valves, an operator would have to don protective clothing to enter the main steam valve house in order to close a manual valve to isolate the ruptured steam generator. The licensee determined that, as a result of the additional time to isolate the steam generator, the potential existed to overfill the steam generator, releasing radioactive liquid to the environment, and possibly exceeding the limits of 10 CFR Part 100.

In response to its finding, the licensee conducted training to reduce the amount of time it would take an operator to don protective clothing and isolate the steam generator. The licensee stated that operators could isolate the ruptured steam generator prior to overfill. To ensure that the limits of 10 CFR Part 100 would not be exceeded in the event that an overfill condition did occur, Maine Yankee administratively limited reactor coolant system activity to 10-percent of the maximum value allowed by TS.

The team reviewed Maine Yankee's EOP transient analyses for two additional events, loss of secondary heat sink and post LOCA cooldown, and did not identify any discrepancies with the information or assumptions used for these transients.

The team conducted walkdowns of selected EOP operator actions performed outside of the control room. Walkdown of actions outside of the control room for establishing HPSI and EFW/AFW, identified by the IPE as important recovery actions, revealed that the procedures were adequate to perform the tasks. Necessary tools were available and valves were properly labeled. Sufficient emergency lighting was installed to allow proper identification of components, with the exception of the upper levels of the main steam valve area. However, the licensee indicated that in an emergency, the operators would be wearing "bunker gear" which has a helmet light that would allow component identification. Also, the licensee was evaluating the installation of emergency lighting in this area. Control room switches were properly labeled, and all valves that might require local operation were also properly labeled.

3.1.3.2 Configuration Controls

Maine Yankee drawings were accurate with a low backlog of drawing revisions. Control room drawings were of good quality and appropriately updated to reflect plant temporary modifications.

Equipment labeling was good. The team noted that labeling on major equipment (valves and pumps) was very good. Labeling on plant instrumentation and gauges was not as good as on valves and pumps, but no deficiencies were noted. During tours of the containment, the team found handwritten markings on the wall that included informal system drawings, component identifications, and a scale used in determining reactor vessel water level when in reduced inventory. The licensee indicated that these were old markings, were not used, and would be removed.

During control room observations, the team witnessed locked valve controls and hanging of equipment tag-outs, including team verification of the adequacy of tagging boundaries. The team also reviewed controls associated with operator information postings. Equipment tag-outs were appropriate and locked valves were properly positioned and locked.

During walkdowns of the SW and HPSI systems, the team found the systems properly aligned and valves properly locked.

3.1.3.3 Restart Readiness Program

The team reviewed the Restart Readiness Program initiated during the extended outage in 1995. The purpose of the program was to achieve an event-free startup, to operate the unit safely and reliably throughout the operating cycle, and to ensure that plant equipment, procedures and staff were well prepared for startup and continued power operation following the extended outage. By initiating the Restart Readiness Program, Maine Yankee management provided additional oversight of the restart effort and performed a systematic and thorough review of equipment readiness. Maine Yankee also reviewed internal and industry operating experience to identify potential pitfalls and good practices related to restarting from an extended outage. The team found that the Restart Readiness Program was generally successful; however, it did not prevent several fuel handling events which occurred toward the end of the outage. As detailed in NRC Inspection Report IR 95-24, NRC staff noted weaknesses in the areas of preparation, training, decision-making, and problem identification, as well as corrective actions associated with the incidents.

3.1.3.4 Operations Performance Assessment Program

The Operations Performance Assessment Program was effectively implemented. The program consisted of periodic self-assessments in the areas of conduct of operations, housekeeping, training, and administrative controls. Management reviewed the results of the assessments for repetitive problems and to evaluate the effectiveness of corrective actions. Negative findings received management attention and adjustments were made to the assessment frequency, as necessary.

3.1.4 Plant Support

3.1.4.1 Fire Protection Program

The team found that the Fire Protection Program at Maine Yankee was receiving increased management attention and resources to address previous problems in this area. Maine Yankee had experienced problems with penetration seals, control of combustibles, and fire protection equipment. As a result of these problems, Maine Yankee instituted a Fire Protection Improvement Plan (FPIP) in 1995. The team found that Maine Yankee had made progress in implementing the FPIP. Planned activities included documenting the design basis for the FP system, inspecting penetration seals, and upgrading the procedures for controlling combustibles and ignition sources. Maine Yankee added a Fire Protection Engineer, planned to hire a new Fire Protection Coordinator, and created a Fire Protection Training Instructor position.

3.1.4.2 Training Program

The team observed four simulator training sessions to evaluate the effectiveness of EOP training. Crews performed well. Recent initiatives to improve training and evaluations, including increased involvement of the crews in critiques, commitments by crews to improve in those areas identified as needing improvement, and objective evaluations of crew communications, were viewed as good enhancements to operator training. The team noted that there was an increased emphasis on improving crew communications. In addition, the team observed that Operations management attended simulator training sessions and participated in the evaluation and critique of crew performance. Simulator training was good and management's participation was a strength.

The team observed a classroom presentation and found that it contained a good mix of lecture, questions, and crew participation.

3.1.4.3 Radiation Protection Program

The team assessed the Radiation Protection Program in the areas of radiation exposure controls, the "as-low-as-is-reasonably achievable" (ALARA) personnel exposure program, contamination controls, and the effectiveness of earlier improvement programs.

The licensee's ALARA program was generally effective in controlling personnel exposure. With the exception of 1995, which consisted of an extended outage to repair steam generators, yearly personnel exposure had declined for all years (outage and non-outage). Maine Yankee management was proactive in the implementation of the ALARA program and had established an aggressive personnel exposure goal for 1996. Daily exposure was discussed at the morning meetings and management recognized that the personnel exposure for the spent fuel pool rerack project was higher than previously expected. As a result, management initiated a review of the work to reassess the ALARA planning and determine if the proper controls were in place to minimize exposure. ALARA planning packages reviewed by the team were thorough, comprehensive, and included ALARA hold-points, the use of training mock-ups, the identification of low dose rate waiting areas, and shielding evaluations. ALARA briefings observed by the team were comprehensive.

Maine Yankee was not effective in identifying and controlling contamination in areas of the plant considered to be clean. The team reviewed the personnel contamination events identified by Maine Yankee in 1996 and found that approximately 50 percent (44 out of 90) of the contamination events occurred in areas that were believed to be clean or uncontaminated.

The radiation protection program had been effective in identifying areas where improvement was needed, but had been less effective at resolving these problems. Specifically, recurring problems had been noted in the areas of unplanned exposure, the control of personnel contaminations, use of procedures, and supervisory oversight.

3.2 Maintenance And Testing Assessment

The team determined performance in the Maintenance area was good overall, however, testing was weak. The results of the operating performance reviews for the auxiliary feedwater (AFW), emergency feedwater (EFW), high pressure safety injection (HPSI), and emergency diesel generator (EDG) systems showed mixed equipment performance. With some exceptions, safety-related pumps and valves operated well, and containment penetration testing has resulted in few problems, reflecting good plant material condition. Communications were found to be good among Operations, Maintenance, and Plant Engineering Department personnel. The Maintenance Department staff did an effective job at identifying material condition deficiencies however some deficient conditions were not identified, such as the poor condition of the circulating water pump building service water (SW) bay space, and AFW deficiencies. The quality of plant maintenance was good as evidenced by minimal maintenance rework issues, and the overall good equipment operating performance. Several instances of equipment malfunctions which occurred during multiple plant shutdown and startup attempts in 1996 indicated declining material condition following the 1995 outage.

Inadequacies in the scope of testing programs were identified, as were weaknesses in the rigor in which testing was performed and in the evaluation of testing results to demonstrate functionality of safety equipment. A lack of a questioning attitude, and stressed resources resulted in the use of poor surveillance procedures and ineffective evaluation of surveillance test data. In contrast to these weaknesses, the extent and types of eddy current testing of steam generator (SG) tubes was evidence of an aggressive and questioning attitude to determine the extent of SG tube cracking. The results of that testing led to the decision to sleeve SG tubes in 1995.
Overall work order planning and tracking was good, however, some weaknesses were found in the work control process.

3.2.1 Equipment Performance

Equipment performance was good overall with some areas being excellent and some being weak. Conditional probabilities which incorporate component availabilities and reliabilities were poor for the AFW system, good for the EDG and HPSI systems, and excellent for the EFW system. Equipment performance of pumps and valves tested in the inservice testing (IST) program was excellent, and containment penetration testing results indicated the capability of the containment to withstand postulated accidents. There were some indications that plant material problems were increasing within the last year as evidenced by operational problems occurring during 1996 that were caused by poor material condition. Plant walkdowns indicated some material condition problems including the poor material condition of the service water bay space in the circulating water pump building.

3.2.1.1 Equipment Performance of Auxiliary Feedwater, Emergency Feedwater, High Pressure Safety Injection, and Emergency Diesel Generators

The team performed an indepth review of equipment operating statistics for AFW, EFW, HPSI, and EDG systems for the time period from January 1, 1992,

through June 30, 1996, (the time period) to determine their individual equipment conditional probabilities. The calculated conditional probability value for each system represents the probability that the system would be able to complete its mission when demanded, and was calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in maintenance for operating conditions 5, 6, and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given that a successful start had occurred). The results of the conditional probability study for the four systems that were reviewed showed mixed equipment performance. Performance of the AFW system was determined to be poor, EFW system was excellent, HPSI system was good, and the EDG system was good. Additional information showing time-dependent probabilities appears in Appendix C.

The findings for each system are detailed below:

(1) Auxiliary feedwater system conditional probability

Based on the results of testing, the AFW system (consisting of one steam driven pump) performed poorly for the time period analyzed and was worse than the performance values assumed in the licensee's Individual Plant Examination (IPE). The licensee's IPE assumed conditional probability of approximately 91-percent, however, the team found that the conditional probability of the AFW system responding to a demand varied over the time period (January 1, 1992 to June 30, 1996) from a high of approximately 82 percent to its latest conditional probability of approximately 76 percent. The licensee was not fully aware of the poor condition of AFW pump P-25B and had not updated assumptions made in their IPE.

The AFW pump P-25B had difficulties both with failing to start and failing to run during surveillance testing. It had a failure to run in October 1992, because of an overspeed trip, a failure to start in January 1993, due to a controller problem, a failure to run in October 1993, due to an overspeed trip, a failure to start in January 1995, due to a controller problem, and a failure to run in June 1996, due to water and oil leakage problems. Due to several overspeed trips and maintenance down time after June 30, 1996, the overall conditional probability would likely drop below 70-percent. The AFW system was a standby system that had not been used by the plant for actual demands, and was designed to be started manually by operators.

(2) Emergency feedwater pump conditional probabilities

The EFW system (consisting of two electrically driven pumps) performed well during the time period analyzed and compared well with the performance values used in the licensee's IPE. The system responded to actual demands following reactor trips during the time period. The system also responded adequately to demands during plant startups and shutdowns.

The system did not respond to all test demands during the period in that EFW pump P-25C had one failure to start during a surveillance test in December 1993, when a breaker tripped open. There were no testing failures for pump

P-25A pump during the time period. The EFW system automatically started and ran successfully on three separate occasions following reactor trips during the time period from January 1, 1992 to June 30, 1996. During each event, the pumps performed as designed.

(3) High pressure safety injection system conditional probabilities

Overall, the HPSI system performed reasonably well during the time period analyzed and compared well with the performance values used in the licensee's IPE, with the exception of "failure to start on demand assumptions." The licensee's IPE would indicate a conditional probability of approximately 99.5 percent, however, the team found that the conditional probability of the HPSI system was better for pump P-14A at 100-percent (does not include test failure in August 1996, caused by a cut wire in the start circuity), and lower for pumps P-14B and P-14S at approximately 98-percent but was improving. The failure to start of HPSI pump P-14A occurred after the period of analyses. Had this test failure been included in the analysis, the conditional probability would have been lower.

The HPSI pumps had few failures during the time period analyzed. There was a failure to start of HPSI pump P-14B in March 1994, due to a breaker problem, and one failure to start of pump P-14S in August 1992, due to an interlock key in bus 6 that would not engage properly. For the time period analyzed, there were no emergency actuations of the HPSI system.

In response to a weakness identified by the team regarding lack of logic testing, the licensee performed some additional testing. A special test of pump P-14A resulted in a failure to start. Troubleshooting activities to determine the cause of the failure indicated that a wire had been inadvertently removed in the safety injection actuation signal (SIAS) start circuit for pump P-14A. Consequently, whenever pump P-14A had been aligned as the alternate pump during normal operation, it would not have received an automatic start signal as designed. If needed, the pump would have to be started manually. The licensee recalculated their IPE with this automatic signal missing to pump P-14A and found that the core damage frequency was increased by approximately six percent.

(4) Emergency diesel generator conditional probabilities

The performance of the EDGs (consisting of two diesels) during testing was good overall for the time period analyzed, and compared reasonably well with the values used in the licensee's IPE. The licensee's IPE would indicate a conditional probability of approximately 91 percent, while the team determined the conditional probabilities for EDG-1A and 1B to be approximately 92 and 90 percent respectively. The 1B diesel had been slowly improving from a weak conditional probability of approximately 88 percent from December 1993, to June 1996, when it reached 90 percent. The latest trend for the 1B diesel was downward to due increased planned and unplanned maintenance.

EDG-1A had one failure to run in April 1996, due to a cooling water pump shaft seal leak and a fuel oil fitting leak. EDG-1B had one failure to start (cause unknown) and one failure to run (cooling water pump seal leakage) in December

1993. The EDGs were not required to be started as a result of an emergency non-test actuation during the time period considered while at power operations.

3.2.1.2 Equipment Performance Demonstrated Through Pump and Valve Testing

Results of pump and valve testing performed as part of the licensee's IST program were very good, and test results showed that critical pumps and valves operated well, indicating good plant material condition. Of the 21 pumps in the IST program, none were in the alert or action ranges which would require either accelerated testing or corrective actions. In addition, of the 381 valves in the IST program, only three were on an accelerated test frequency program due to stroke times in the alert range. Along with the IST results, vibration data were collected through the predictive maintenance program which was used to assess the performance of rotating equipment. The rotating equipment log was used effectively to document items requiring additional monitoring and correction.

3.2.1.3 Containment Performance Demonstrated Through 10 CFR 50 Appendix J Leak Rate Testing

Results of testing performed in accordance with 10 CFR Part 50 (Appendix J) for containment penetrations revealed few problems. These test results indicated the acceptability of the containment as a barrier to fission product release and that containment leakage criteria were met. For example, seven integrated leak rate tests (ILRTs) were accomplished since 1972 (1972, 1975, 1979, 1982, 1985, 1988, and 1992), resulting in one test failure (1985).

Some repetitive problems had occurred while performing local leak rate testing (LLRT). Testing of containment purge valves over the last few years has resulted in some failures that were adequately addressed by the licensee in 1995. The main cause of the failed tests was determined by the licensee to be an improper adjustment of an actuator during maintenance activities. In addition, the licensee had established a close out plan to identify and track issues with purge valves in general. Additional repetitive testing failures involved the containment sump isolation valves caused by debris in the sump such as tie-wraps, weld rod and safety wire. The LLRTs for these valves had routinely exceeded the administrative limit of 2.0 pound mass (lbm)/day and their inoperable limit of 10 lbm/day. The last five tests (performed since December 1995) were above the administrative limit, but below the inoperable limit. Proposals had been suggested to provide additional trench screens and to clean the sump and containment trenches during the 1997 refueling outage.

3.2.1.4 Equipment Problems Trending Upwards

Plant material condition at Maine Yankee had been good over the last few years but during 1996 there were indications that equipment problems have been increasing. During the three years prior to the 1995 steam generator repair outage, Maine Yankee experienced a generally good plant operating performance record and plant material condition.

Since coming back on-line in January 1996, the overall performance of Maine Yankee had been mixed. Although the unit was placed in service on January 16, 1996, power was reduced from 18 percent to less than 10-percent, and the main generator was taken off the grid to repair a main generator cooling control valve. The reactor tripped on February 13, 1996, when a feedwater valve positioner failed, and on July 14, 1996, power was reduced to locate a small leak in a condenser waterbox.

A plant outage to perform modifications to the primary component cooling water (PCCW) system piping began on July 20, 1996. During the plant shutdown, several equipment problems occurred, including the trip of a motor-driven main feedwater pump upon manual start, the slow response of main feedwater regulating bypass valves, and the inability to insert the control element assemblies in manual sequential mode. During the outage, additional equipment problems were identified that needed to be addressed prior to startup, including operability problems with AFW pump P-25B, excessive leakage of a residual heat removal valve (RH-4), and identification of safeguards equipment actuation logic testing deficiencies and associated equipment problems. The attempts to restart required the licensee to change operating conditions many times to address equipment concerns. After completion of repairs, the plant was returned to service on September 2, 1996. The number of equipment problems identified in 1996 indicated that problems were trending upwards following the 1995 steam generator repair outage.

3.2.1.5 Plant Walkdown Observations

The team conducted walkdowns throughout the plant. There were noteworthy observations of PCCW piping corrosion, service water (SW) pump bay degraded components, and cleanliness problems within the containment building. The team observed extensive external corrosion on a large portion of the PCCW piping within containment during a walkdown. This problem was previously identified and was monitored by the licensee. The corrosion, while creating a visible appearance of an extremely poor material condition, did not prevent the piping from performing its safety function and had been monitored by the licensee. The licensee indicated that portions of the corroded PCCW piping located inside of containment would be replaced with stainless steel piping during the 1997 refueling outage.

Team walkdowns of the SW pump bay in the circulating water pump building also revealed extensive material condition problems, such as water on the floor, corroded fasteners, corroded supports, pump base plate corrosion, missing u-bolt hanger parts, and cracked grout pads. After the team identified these problems, the licensee performed an in-depth inspection of the SW pump area, and found additional problems, which included a disengaged support (caused by the lack of weld penetration) for the raw water line leading to SW pump P-29B. The pump was declared inoperable until a preliminary analysis indicated that the pump could withstand applicable loads despite the degraded support. The licensee indicated that resources would be made available to greatly improve the material condition of the SW pump bay.

The licensee had not effectively inspected the containment for cleanliness after the outage. Team observations inside the containment indicated that

housekeeping required greater attention to eliminate inappropriate foreign material or items left over from maintenance activities. During inspections inside of the containment, the team identified problems with housekeeping and cleanliness, such as items wrapped in unqualified plastic, and discarded tape. During followup inspections, the licensee found uncontrolled tools in the containment. The licensee implemented an initiative to replace plastic coverings utilized inside the containment with high-temperature qualified material.

3.2.2 Problem Identification And Resolution

The Maintenance Department staff was effective in finding and documenting material condition deficiencies within the plant. They also identified and initiated the majority of corrective and non-corrective work orders (WOs). The WO process was the primary process used to initially identify and correct deficiencies. However, the effectiveness of the problem identification and resolution process was inconsistent. In many instances, testing was not an effective tool in identifying problems. A lack of a questioning attitude during test performance and evaluation was not conducive to discovering equipment problems, but rather to accepting equipment performance.

Walkdowns of plant systems indicated that some deficient conditions were not being identified by either of the three main groups (Maintenance, Engineering, and Operations Departments). These included the poor conditions of the circulating water pump building SW bay space and AFW pump P-25B deficiencies.

Depending upon the type or severity of a deficient condition, the licensee used other corrective action processes to evaluate the cause. The main corrective action program used by the Maintenance Department to review rework was not fully effective and, in some cases, failed to identify substantive problems or trends. Procedure No. 67-300-1, "Maintenance Self-Assessment Program (MSAP)," established a system for maintenance rework identification and corrective action follow-through. The procedure provided a system for equipment trending to identify recurring problems and to determine appropriate corrective action, and provided a system to enhance availability of lessons learned during previous maintenance evolutions. For example, rework and repetitive failures associated with the AFW and EFW pumps were not identified by the program as issues. Examples that were found indicated that the program was not always effective and in some cases the organizations at Maine Yankee were not communicating and cooperating with each other to identify and prevent repeat problems. Maine Yankee had identified this deficiency and was in the process of integrating existing fragmented corrective action programs with the intent of being more effective in identifying, resolving, tracking deficiencies, and minimizing repetitive failures.

The resolution of the Magne-Blast breaker problems demonstrated an effective program that corrected manufacturer equipment component defects and workmanship. Beginning in September 1993, the licensee experienced many problems with 4.16 kV and 6.9 kV Magne-Blast breakers. Problems with the breakers at other plants had also been observed and had continued to be identified by the industry during 1996. As a result of the various breaker issues commencing with the 1993 occurrence, a significant testing and

inspection program was implemented by Maine Yankee to resolve these problems, including consultation with the manufacturer, General Electric. The process was characterized by good focus, proactive approach, organized and comprehensive tracking of issues, clear communication, and traceability of documentation.

3.2.3 Quality of Maintenance

The quality of plant maintenance was good, as evidenced by good overall plant material condition, good equipment operating performance, and a competent Maintenance staff. However, several instances of equipment malfunctions which occurred during recent plant shutdown and startup attempts indicated a declining trend in material condition.

Equipment problems that delayed recent plant startups or complicated shutdowns included, repetitive AFW pump P-25B problems, leak-by of valve RH-4, foreign material in steam generator blowdown valve BD-T-12, a motor-driven feed pump trip, a slow response of a main feedwater (FW) regulating by-pass valve, and the inability to operate the control element assemblies (CEAs) in manual sequential mode.

The team observed or reviewed several maintenance activities. Pre-job briefings were noted as excellent. In general, procedure use and adherence were appropriate, but there were some instances of poor maintenance work practices.

(1) Failure to implement vendor recommendations for EFW pump P-25A

During 1995, the licensee overhauled EFW pump P-25A, as a result of vendor recommendations to replace certain carbon steel pump internals with stainless steel parts because of previous incidents of internal component cracking. At the same time, additional internal pump parts were replaced. After reassembly of the pump, the licensee noted a binding of the pump internals when the pump was hand rotated during troubleshooting activities. Because of the binding, the new internals were subsequently removed and the old internals were reinstalled. During the final stages of the reinstallation of the old internals, the licensee had not performed a magnetic particle inspection of the "used" pump diffusers prior to reassembly as recommended by the manufacturer. However, it was also noted that the pump had performed well since January 15, 1996.

(2) Work order instructions not followed, service water system declared inoperable

Licensee communication weakness resulted in a degraded condition of the SW system during maintenance on a seismic piping support. This event, which was discovered and reported by the licensee, related to a single event involving a problem of WO adherence and potential communication inadequacies. A maintenance Section head discovered that Maintenance personnel had removed a seismically qualified pipe support on a seal water line for SW pump P-29C without tagging out the pump. The support was removed to the "cold shop" when only prefab work was allowed by the WO. This condition was reported to the

control room, and the operators declared the pump inoperable on August 13, 1996. The support was repaired, and the pump was subsequently declared operable on August 17, 1996.

(3) Poor foreign material exclusion work practices resulted in a failure of steam generator blowdown valve, BD-T-12.

On August 18, 1996, following repeated attempts to close valve BD-T-12 (a containment isolation valve), the valve was declared inoperable because it would not completely close. When the valve body was disassembled, a piece of weld rod was found lodged in the seat, preventing the valve from closing. The licensee was unable to determine the source of foreign material.

(4) Lack of procedural detail for installation and control of fastener lockwire

A lack of WO detail resulted in a failure to reinstall fastener lock wire on components following maintenance activities. The team discovered that lockwire was missing during a containment walkdown involving five in-core instrumentation seal housings and on motor-operated valve (MOV) actuator mounting bolts for reactor coolant (RC) valve RC-M-32. These conditions did not pose an immediate safety concern, however, the licensee generated WOs to install the missing lockwire. The licensee also took actions to review and revise procedures involving lockwire installations.

3.2.4 Testing Weaknesses

The team found inadequacies in the scope of testing programs, and weaknesses in the rigor in which testing was performed, and in the evaluation of testing results to demonstrate functionality of safety equipment. Despite the many inconsistencies between information contained in the Final Safety Analysis Report (FSAR) and the as-built condition of the plant (See Section 2.4), the licensee did not recognize a need to review and reconcile test procedures with design requirements, and to correct these errors. A lack of a questioning attitude resulted in the use of poor surveillance procedures, and in the ineffective evaluation of surveillance test data to determine equipment operability. Of the test procedures that were reviewed, the team found several examples of tests that had been developed, performed, and evaluated many times without questioning the validity of the test results. Examples include:

(1) Poor emergency diesel generator testing procedures

A large number of important electrical time-delay relays were not verified for proper operation and were not in the licensee's calibration program. The team identified that the 10 and 20 second EDG load sequencing relays had not been calibrated since installation, the tolerance band and acceptance criteria had not been established, and these relays were not in the Maine Yankee Calibration Program. The team also identified that the actuation time of the 10 and 20 second sequencing time delay relays and the tolerance acceptance criteria for the relays were not logged on the surveillance procedure, and the 20 second timer actuation was not verified in the procedure. The procedure

was also incorrect in that the signoff for the 20 second timer actuation was listed in the procedure as 30 seconds. The procedure had been performed many times without questioning the 10 second error in the timing sequence.

Based on the team's questions in this area, the licensee identified several other relays that were not tested or included in their calibration program. These relays included, the motor-driven fire pump start permissive relay and the permissive relays to remove the low pressure safety injection (LPSI) pump trip 10 seconds after the recirculation actuation signal to allow manual restart of the pump. The licensee indicated that an appropriate calibration interval would be assigned to these relays.

(2) Control room ventilation test results not properly evaluated

The licensee failed to question the adequacy of a surveillance test used to determine if a positive differential pressure (dp) existed between the control room (CR) and adjoining rooms or buildings, and the assumptions used in a Yankee Atomic Electric Company (YAEC) calculation issued to justify the operability of the CR ventilation system. On October 31, 1995, a negative dp was observed during a surveillance test. The procedure required a positive dp to be acceptable. On December 12, 1995, YAEC issued a memorandum to the licensee, which justified operability of the CR ventilation system in response to the test results. However, the YAEC calculation failed to incorporate the negative pressure results in the calculation (based on engineering judgment and control room pressure history the analyst assumed that the pressure was positive). Subsequent to the YAEC memorandum, the licensee failed to question the assumptions in the YAEC response and declared the CR ventilation system operable. Based on the team's concern that no corrective actions had been taken to address the failed CR ventilation surveillance test, the licensee performed an extensive dp surveillance and determined that current CR dp was positive. Further review of the October 31, 1995, failed test and the YAEC calculation assumptions by the licensee indicated that the CR ventilation system was inoperable from the failed test in October 1995, until the successful retest in August 1996.

(3) Inappropriate inservice test procedures for check valve testing

The methodology used in test procedures to verify closure of safety-related pump discharge check valves in the IST program was inappropriate. The team observed the performance of surveillance test 3.1.22, Revision 15, "Emergency Feedwater System Cold Shutdown Flow Test," and questioned whether the specified pressure instrument and test methodology was acceptable to measure backleakage through the check valve. The licensee concluded that the instrumentation was not appropriate for the test application and retested using a pressure instrument at an alternate location. The licensee later determined that this too was an unacceptable test method because the EFW suction piping was connected to an open system. For the EFW system, the licensee determined that measuring reverse flow through the check valve was the method that should be used. The licensee initiated a review to determine if other systems were similarly affected, identified procedural inadequacies, and declared that the HPSI, LPSI, PCCW, secondary component cooling water (SCCW), and EFW systems were inoperable. The licensee reviewed results of

other tests of the affected systems, revised test procedures, and retested the valves to determine system operability. Subsequent test results were acceptable. The licensee reported the issue to the NRC in LER 96-028 on August 28, 1996.

(4) Emergency equipment actuation circuitry not adequately tested and HPSI pump P-14A discovered incapable of starting on SIAS when in standby mode

The team reviewed procedure 3-1.15.2, Revision 17, "ECCS Operational Test Recirculation Actuation System," and identified that the recirculation actuation signal (RAS) circuitry for the CS pump P-61S was not tested and verified. The licensee concurred with this finding and concluded, due to the similarity of the circuits, that there were also portions of HPSI pump P-14S circuitry that were not being tested.

The licensee stated that even though the circuits were not fully tested, the systems were in compliance with the technical specifications (TS). The team disagreed with this interpretation on the basis of the TS definition of operable and the requirements in TS Table 4.1.2 that required complete testing of SIAS actuation relays. The licensee decided to perform additional tests prior to increasing power above two percent that would verify that the HPSI pumps (P-14A, P-14B and P-14S) would start from the standby mode through exclusive actuation of the SIAS relays. During this testing on August 17, 1996, HPSI pump P-14A failed to start due to an open lead (cut wire) that interrupted the start signal from the logic relay to the pump controller. The cut wire was found to have been partially removed (about 15 feet of wire was missing) with the remainder of the wire marked as "spare" in the wiring bundle at the main control board. The plant was brought to cold shutdown to make repairs, and Unusual Occurrence Reports were written to document the testing problems found on the HPSI pump P-14A and CS pump P-61S.

(5) Additional examples of insufficient logic testing identified and equipment deficiencies discovered

In response to the team's questions concerning the adequacy of logic testing and as part of its implementation plan in response to NRC Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits," the licensee initiated a surveillance testing closeout plan to identify and correct other potential testing discrepancies. Several additional examples of insufficient logic circuit testing were identified involving the SIAS, CS actuation, RAS, containment isolation, feedwater trip, EFW initiation, reactor protection, EDG actuation, and main steam isolation systems. For the circuit testing that was completed prior to startup, three additional equipment deficiencies were identified that required repair; (1) a stuck relay in the CS pump P-61S circuitry was replaced, (2) a suction pressure switch on HPSI pump P-14B was replaced, and (3) a breaker for CS pump P-61S cycled when the undervoltage device was reset. The breaker trip was being investigated by the licensee.

(6) Control board annunciator fault alarm circuits not periodically tested

The team reviewed the licensee's emergency core cooling system surveillance procedures and identified that four annunciator fault alarms were not tested

or operationally checked and verified by procedure. These alarms provided indication of a defect, such as loss of continuity, in the circuit.

(7) Standby power meters required by Regulatory Guide 1.97 not calibrated and periodically tested

The team identified that the licensee had excluded most instrumentation meters required by NRC Regulatory Guide (RG) 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," from its calibration program. The licensee stated that the volt meters and ammeters for the inverters, battery chargers, DC buses, EDGs and emergency buses were determined to be out of the scope of equipment that required calibration to support operability determinations. The licensee had concluded that the only standby power instruments that required periodic testing and calibration were the power and reactive load meters for the emergency diesel generators. The team disagreed with this position. Further discussions with the licensee indicated that the additional meters would be added to its calibration program.

(8) Lack of calibration for EDG room exhaust fan thermostat

The team identified that the EDG room thermostats were not periodically calibrated and were not in a calibration program. The thermostats were calibrated when installed in 1990, and they were functionally checked to ensure that the exhaust fan started; however, the thermostat actuation point was not recorded and no acceptance criteria was applied. Since the operation of the EDG room exhaust ventilation fan affects the ambient air temperature, the thermostat calibration could potentially increase the need to derate the EDGs kW output limit. For example, ambient air temperatures above 90 °F , combined with jacket water temperatures above 190 °F (LOCA conditions) would require a derating of the electrical output of the EDG. These factors were not accounted for in the EDG loading calculations.

(9) Recirculation actuation signal manual trip switch contacts not effectively tested

The team identified that trains "A" and "B" RAS manual trip switch contacts were not functionally tested in procedure 3-1.15.2, Revision 17, "ECCS Operational Test Recirculation Actuation System." The test procedure inappropriately tested the RAS manual contacts with the RAS automatic signal present, thereby not assuring that the RAS manual trip switch contacts were actuated during the RAS manual test.

(10) Importance of air-operated valve testing recently recognized

Although the air operated valve (AOV) testing program was in general compliance with the licensing basis and applicable regulations, the testing did not effectively verify the functionality of safety-related AOVs in design applications for safety-related systems. A large percentage of remotely operated valves at Maine Yankee were AOVs rather than motor-operated valves (MOVs). The reliance on AOVs to perform safety functions should have

commanded earlier management support for a comprehensive AOV testing program that would ensure reliable operation. Although the regulatory requirements to verify design functions under realistic accident conditions were not as explicit as for MOVs, the licensee was mandated by their design criteria, technical specifications and the FSAR to adequately test the safety-related valves to verify that they would operate under accident flows and pressures. In addition, inservice testing did not adequately verify functionality of AOVs under representative accident conditions.

There were examples of AOV testing failures at Maine Yankee that may have been preventable if a comprehensive testing program had been in place. Recent examples included the failure of the FW regulating bypass valves (FW-A-112, 212, 312) to completely isolate during a reactor shutdown, the leakage detected during IST testing in the EFW isolation valves EFW-A-101, 201, 301, 338, 339, 340), and the failure of a blowdown trip isolation valve (BD-T-32) to close due to insufficient actuator spring pressure.

Additionally, approximately 10-percent of the station AOVs were included in the IST program. Many of the valves not included in the IST program performed safety-related functions such as the temperature control valves for the PCCW and SCCW systems (PCCW-T-19, 20 and SCCW-T-23, 24). Despite a history of actuator problems, these valves were not in the IST testing program.

The Maintenance Department had recently recognized the need for a comprehensive AOV testing program and was in the process of obtaining funding to procure the required diagnostic and testing equipment, and program training.

(11) Reactor-Water storage tank level transmitters overheated

During the ISA team's review of the temperature range used for RWST level setpoint calculations, a walkdown was performed by the licensee as a result of the ISA team's inquiries. The walkdown resulted in finding transmitter enclosures for train B that were heated above the transmitters' design temperature of 130° F. This condition caused the transmitters to be in an unanalyzed condition, invalidated the setpoint calculation for these transmitters, and caused two transmitters to exceed their qualified life. The resultant setpoint change was slightly non-conservative and did not affect the operability of the ECCS pumps. The transmitters were subsequently replaced.

3.2.5 Maintenance Work Order Control

Overall WO planning and tracking was good. The use of the On-Line Maintenance Risk Management Program to set maintenance work priorities at Maine Yankee was excellent. Extensive risk-based methodologies were used at many levels by the licensee. The basis for some of the risk information may not be as conservative as previously assumed, as was the case for AFW pump P-25B which had a conditional probability (overall probability for success) much less than that specified in the licensee's IPE because equipment failure data had not been updated. Both the licensee and the team had identified some inconsistencies and inefficiencies with the WO process, and there was a large

backlog of open WOs (some dating back to 1991) where the actual work had been completed, although closeout of the work package was not yet performed.

3.2.5.1 Use Of Probabilistic Risk Assessment Methodologies

In support of the licensee, the YAEC organization had established and implemented extensive probabilistic risk assessment (PRA) methodologies to assist in making risk-informed decisions to perform maintenance and testing activities. Yankee Atomic personnel were very experienced in PRA techniques, and the licensee was accustomed to using PRA insights on a daily basis. The licensee established an On-Line Maintenance Risk Management Program to manage risk. This program effectively used insights from the PRA to help plant personnel, on a daily basis, make decisions concerning maintenance and testing of equipment. Risk assessments used by the Operations and Maintenance staffs to plan and schedule work were relatively simple. These assessments may not be as conservative as assumed, as was the case for AFW pump P-25B who's performance was much worse than that specified the licensee's IPE. Individual WOs were prioritized using risk perspectives to ensure that the most risk significant work was accomplished first. To accomplish this task, the WO process established specific equipment priorities based upon PRA information.

3.2.5.2 Work Planning And Tracking

Overall WO planning and tracking was good. Some weaknesses were found in the work control process, however, the licensee was assessing how to improve WO efficiency. In addition, the database used to capture individual WO activities was useful in determining who initiated the WO, its priority, age, outage or nonoutage condition, safety or nonsafety-related condition, WO status, and many other parameters. The capabilities of the WO tracking system were under-utilized as a tool to aid management in understanding the status of WOs.

The licensee encouraged anyone, upon discovery of a deficient condition, to initiate a WO without intervention from others. However, a review of the 1995 steam generator outage WO statistics indicated there was a high percentage of WOs that were canceled, deferred or voided after the WOs were entered and prioritized. This practice produced administrative inefficiencies which were largely caused by duplicate WOs, lack of initial deficiency tagging of components, or a subsequent determination that a WO was not required after one had been initiated. A review of open WOs showed that there was a backlog of 185 WOs (many greater than one year with the oldest being 1991), where the work had been completed, including functional testing, but the work package was not yet closed out.

The processes used to perform work within the Maintenance Department differed between the mechanical, electrical, and instrumentation and control groups which caused some minor work control inconsistencies in tracking and trending of work. These work control differences also affected the reporting of monthly WO statistics, in that preventive maintenance or surveillance testing activities may or may not have been included in WO statistics.

Work involving temporary repairs using sealants or coatings such as Furmanite and Belzona were well controlled and tracked. The team identified that no temporary sealants were in use in safety-related applications at Maine Yankee.

3.3 Engineering Assessment

The quality of engineering work was mixed but considered good overall. Strengths were noted in the capability and experience of the engineering staff, day-to-day engineering support of maintenance and operations, in the quality of most calculations, and in the routine use and application of analytic codes. However, engineering was stressed by a shortage of resources, and there was a tendency to accept existing conditions. Specific weaknesses were noted with inconsistent identification and resolution of problems, inadequate testing, and work on some calculations and analytic codes.

3.3.1 Identification And Resolution Of Problems

The team found that, although the overall contribution of engineering to the identification and resolution of problems was generally good, some significant weaknesses were evident.

There were many examples of appropriate resolution of problems. These included the addition of safety-related ventilation fans in the EFW pump room, the recent addition of relief valves in the PCCW piping, the sleeving of the steam generator tubes, and the modification in progress for improving the ventilation supply into the containment spray building. However, in some cases, these were longstanding design deficiencies, that could have been resolved much earlier. The Plant Engineering Department gave very good support to operations and maintenance in solving day-to-problems.

Through its IPE and IPEEE programs the licensee had either resolved or was in the process of resolving other issues. Safety improvements had been made, such as resolution of the lack of safety-related ventilation for the EFW pump room (identified in late 1995 and corrected in early 1996), the addition of a spare inverter, consideration and compensatory measures to accommodate turbine building flooding, and consideration of a larger spectrum of high-energy line breaks in the turbine building, for which compensatory measures had also been taken.

However the team also found:

- deficient design conditions that had not been entered in a corrective action system or were dropped,
- corrective action for problems that was not appropriately expanded to look for similar issues, and
- other long-standing deficient conditions.

Examples of issues for which appropriate corrective actions were not taken were (1) a design deficiency noted in 1991 by a YAEC engineer who described the potential to lose safety-related ventilation flow into the containment

spray building due to the closure of ventilation dampers utilizing a non-safety-related source of instrument air and (2) the limitation of the atmospheric steam dump valve to relieve only 2.5 percent power which was identified in the mid-1980s, dropped as an issue needing resolution, and resurfaced by the licensee in 1996.

Examples of deficiencies that could have been found if the corrective actions were appropriately expanded to look for similar issues included problems with the ventilation systems in the protected switchgear room, the containment spray building, the control room, and the emergency diesel generator room.

Other examples of long-standing deficiencies missed, or not effectively pursued, were identified in the environmental qualification (EQ) program and equipment testing.

The team noted the lack of a conservative testing philosophy that resulted in the identification of numerous safety-related components that were not being periodically tested or calibrated. The team also found specific testing weaknesses with recirculation actuation signal (RAS) manual actuation, the P-61S CS pump, control room fault annunciators, the EDG room ventilation thermostat, Agastat relays used for timing safety-related components, and various safety-related valves (CCW bypass, check valves). As a result of the team's findings in this area, an operability problem was identified with HPSI pump P-14A. As a followup to the team's concerns, licensee testing revealed that HPSI pump P-14A would not have started automatically on a safety-injection signal with offsite power available, although the pump could have been started manually.

The service water operational performance inspection (SWOPI) performed by the licensee was effective at identifying problems; however the licensee stated that the evaluation and resolution of these problems were delayed by resource constraints resulting from the steam generator tube sleeving effort in 1995.

3.3.2 Engineering Programs

The engineering staff was technically competent with particularly good historical knowledge of the plant. The relationship between Maine Yankee and Yankee Atomic (YAEC) appeared to be a significant positive factor. There was extensive technical expertise within the YAEC organization, and its degree of familiarity with the Maine Yankee facility surpassed what could be expected in a normal client/architectural engineering firm relationship.

The team assessed Engineering programs relating to (1) closure of NUREG-0737 responses to TMI action items, (2) modifications and temporary modifications, including the performance of 10 CFR 50.59 reviews, (3) erosion/corrosion detection in piping systems, (4) and the SWOPI effort. This assessment was performed by reviewing procedures and selected program documents, as well as by discussions and interviews with licensee personnel. Maine Yankee audits and assessments were reviewed to determine the effectiveness of Maine Yankee self-identification and correction of problems related to these programs.

3.3.2.1 Engineering Modifications And Temporary Modifications

The team reviewed the program for plant design changes and modifications, including procedures and selected program documents, and held discussions and interviews with licensee personnel. Audits and assessments were reviewed to determine if self-identified problems had been corrected.

The procedures were good, meeting the requirements of ANSI N45.2.11 "Quality Assurance Requirements for the Design of Nuclear Power Plants." Reviewed modification packages were also good. The 10 CFR 50.59 reviews and screening documents reviewed were generally correct. Temporary modifications were acceptable; however, some temporary modifications had been installed for a long time (approximately 10 years). The licensee was aware of this condition, and had recently made some improvements in this area to reduce the number of temporary modifications. Licensee weaknesses and problems identified in self-assessments and audits in the area of modifications were appropriately corrected or were in the process of being corrected.

3.3.2.2 Erosion/Corrosion (E/C) Program

The licensee's Erosion/Corrosion Program was difficult to assess because the common industry practice of using a computer based program to determine inspection points was not being used. Although weaknesses were noted, the E/C program was considered adequate.

The licensee strengthened its program following the failure of a moisture separator reheater scavenging vent elbow in 1992. Immediate corrective action included a complete rewrite of the E/C implementing procedure to make it more effective. The changes comprised a program and process to facilitate consistent implementation, screening of all piping for susceptibility to E/C, a documented basis for any exclusion, qualitative analysis of all susceptible lines, a process for selecting components for inspection, and documentation of actions taken on all industry experience.

The licensee also stated that it was making plans to use the EPRI CHECWORKS software but did not commit to an implementation date.

In certain cases, the licensee had replaced adjacent piping when it replaced fittings as a result of E/C testing. Whenever possible, the licensee used replacement components fabricated of steel having 2.25 percent chrome content, which the licensee stated reduced E/C rates by at least a factor of four. The licensee stated that its control of water chemistry by (1) the use of morphaline, (2) raising the cold condensate Ph to >9.2, and (3) maintaining oxygen in the condensate at <5 ppb had significantly reduced the corrosion rate for the affected systems.

The E/C program covered approximately 3000 fittings, of which approximately 826 had been replaced as a result of excessive wear. Historically, the plant has had limited success at preventing leaks. The plant had six small leaks in high-energy piping included in the program, four of these were pinhole leaks, and two of which were in fittings that had been inspected and had subsequently leaked.

There had been several small leaks in secondary drain lines to the main condenser, and during the last outage, the licensee failed to replace components on WO 94-02568-00 related to high pressure drain trap 15, which had been identified as having E/C.

3.3.2.3 Service Water Operational Performance Inspection

The SWOPI, which the licensee performed in 1994, was comprehensive and insightful. It identified over 155 findings related to the service water system, PCCW, and SCCW systems. At the time of this assessment, 18 SWOPI findings were not closed. These 18 findings involved the adequacy of cooling of the EDGs, testing and trending of heat exchanger efficiencies (fouling) required for safety analyses, and the absence of "a formal set of minimum heat transfer requirements related to containment heat removal" to support containment safety analysis. Resource impacts of the SG sleeving outage impacted the scheduled completion of these potentially significant items.

The team reviewed the SWOPI report and the responses to its findings in detail. Many of the items discussed in this report in Section 2.2.2 were identified in the SWOPI self-assessment but were not yet fully resolved. For example, even though work had been started, an effective program was not in place to ensure that the heat exchanger fouling did not exceed the bounding values assumed in calculations.

3.3.3 Design-Basis Information

The quality and availability of design basis information (DBI), including drawings, calculations, and other documents containing detailed design information, was good overall but varied in quality depending on the functional area.

Design basis documents were reviewed for safety related and important to safety systems. Calculations varied with the engineering discipline. Electrical calculations were typically excellent and recently revised. Some mechanical calculations were easily misinterpreted because there were portions of various revisions to the same calculation considered applicable. The earlier calculation revisions were not annotated to identify that they were "superseded" or "void." In general, electrical DBI was excellent and mechanical DBI was good.

Design basis summary documents (DBSDs) were produced as part of an ongoing program to consolidate available design information on selected systems. This program had been in effect for about 10 years. The design basis recovery (DBR) for each system was accomplished primarily by creating a DBSD for the system. The 10 functional areas for which DBSDs had been developed were HPSI, LPSI, CS, EFW/AFW, PCCW/SCCW/SW, instrument air, control room habitability, flooding, station blackout, and Appendix R (fire protection). There were no DBSDs as yet for nine areas identified in this program, including the emergency diesel generators (EDGs), electrical distribution, ventilation (partial), reactor protection, and safety-actuation signals (SAS). The overall quality of the DBSDs was good and they provided a valuable roadmap to other applicable documents and calculations. However, the team found that

they could not be completely relied upon without verification in that there were some minor discrepancies. Maine Yankee implemented an Inputs and Assumptions Source Document (IASD) in 1986 in response to an NRC confirmatory action letter in 1982. The IASD contained key parameters (important to safety and operator controlled) that were assumed in safety analyses. There was no similar document to provide configuration control of the numerous other safety-related parameters required in design and licensing-bases calculations and plant procedures. The licensee had identified weaknesses in the IASD and was working to replace it with a more comprehensive document called the Safety Analysis Information Document (SAID), which had a projected completion date of 1997. Completion of this effort was delayed as a result of the SG sleeving project.

As-built drawings were identified for all safety-related piping covered by NRC Bulletin 79-14, "Seismic Analyses For As-Built Safety-Related Piping Systems," (which included most safety-related piping) and for other specific Maine Yankee projects such as main control board verification. Other drawings had been verified on an as-needed basis, and, as a result, other systems such as SW, lacked a complete set of as-built drawings. The team walked down portions of the HPSI, CS, and EFW/AFW systems, verifying the as-built drawings against the plant configuration. A few errors were noted on the drawings walked down by the team, but none of these errors were significant. The overall quality of drawings was very good.

3.3.4 Quality Of Engineering

The team reviewed numerous engineering calculations and found their quality to be mixed and good overall. Deficiencies included errors and inappropriate assumptions. A weakness was also noted in the overall control of calculations.

Most of the calculations reviewed were detailed, comprehensive, and rigorous, particularly in the area of electrical design. However, there were examples of significant calculational deficiencies including the EDG loading calculation (approximately 200 KW of load was not accounted for), the NPSH calculation for the containment spray pumps (incorrect suction piping head losses and other inappropriate assumptions), and the heat load calculation for the CCW systems (inappropriate assumptions). These and other examples are discussed in more detail in Section 2 of this report.

The quality of 10 CFR 50.59 analyses was considered good, however the team found several isolated deficiencies of these analyses, such as, for a change to the RWST high-level alarm, consideration was not given to the potential for the consequences of adding more water to containment following an accident thereby potentially impacting environmental qualification of instrumentation.

The licensee had recently identified other problems with regard to 10 CFR 50.59 analyses. Before the team arrived onsite, the licensee initiated a review of selected FSAR sections to insure that the licensing basis of the plant was correctly stated. At the time of the ISA, this effort was partially completed but resulted in over 100 Apparent Discrepancy Reports, of which approximately 50 will require FSAR changes and accompanying 10 CFR 50.59 reviews.

A weakness in the control of calculations was noted. For example there were two active revisions of calculation MYC-272, "NPSH Study, Containment Spray Pump." Revision 2, of this calculation was the basis for the injection phase NPSH, and Revision 4 of this calculation determined the suction piping frictional losses for the recirculation phase. Revision 2 was not annotated to identify that a portion of this calculation was superseded by a later revision. Calculation MYC-1731, Revision 0, dated August 26, 1994, calculated the post-LOCA containment sump temperature at 263 °F. This calculation should have been superseded since the sump temperature of record was 255 °F, developed from calculation MYC 1740, Revision 1, dated June 25, 1996.

The ISA team found the SW system design calculations, and the Engineering Directive that provided operational guidance based on these calculations, to be an example of excellent engineering work. This directive summarized a number of complex interrelated parameters in a clear format. However, the limits established in this directive were not consistent with the FSAR (see Section 2.2.2.6), but this inconsistency was not safety-significant.

4.0 SELF ASSESSMENT, CORRECTIVE ACTIONS, PLANNING, AND RESOURCES

Weaknesses were identified in the areas of problem identification and resolution. While licensee self-assessments were generally good, they occasionally failed to identify weaknesses or incorrectly characterized the significance of the findings. Additionally, some corrective actions were not timely and others were ineffective, leading to repetitive problems. Licensee planning was generally effective, although some weaknesses were found in the overall implementation of improvement plans. Some economic pressures resulted in limitations on resources, which impaired the licensee's ability to complete improvement projects that affected plant safety. Equipment problems were not resolved and improvement programs were not effectively implemented because the licensee perceived them to be of low safety significance.

The team (1) assessed the licensee's programs, procedures, and actions in the areas of problem identification and resolution, planning, and resources and (2) evaluated timeliness and effectiveness of corrective actions. The team conducted more than 100 formal interviews, observed numerous meetings, reviewed relevant documents, and used the technical findings discussed in Sections 2 and 3 as a basis for its assessment.

4.1 Self Assessment

The licensee's demonstrated ability to identify and assess problems affecting plant performance and safety has been adequate. Numerous examples of internal and external assessments revealed a pattern of identifying problems and characterizing them effectively for station management. However, while many problems discussed in this report had previously been identified by the licensee, some notable problems had not been adequately identified or characterized.

Management encouraged all levels of the plant organization to identify performance problems. There was no evidence of a general reluctance to raise perceived safety concerns to station management. Interviews consistently indicated that the workers often highlighted problems in the plant and did not fear reprisals from supervisors or management. Management oversight of plant activities was adequate in assuring problem identification with some notable exceptions such as the failure to identify design problems in the ventilation systems and testing deficiencies of safeguards logic circuits. The active presence of key managers inside the plant, and the use of the zone inspection program have strengthened the oversight of many programs and activities throughout the plant. However, the team noted that supervisors occasionally missed obvious problems within the plant such as deficient material conditions in the service water pump bay and foreign material that remained inside the containment after closeout.

The Performance Assessment Program was generally effective in providing line management assessment of performance in individual departments. Each department manager assigned specific areas to department supervisors and other qualified personnel for problem identification and assessment. The effectiveness of these programs varied between departments. The Operations and Maintenance Departments were effectively identifying problems; however,

the Engineering Department had implemented the program, but had not conducted a sufficient number of assessments to provide meaningful feedback.

The Quality Control (QC) Program was effective in identifying problems and maintaining the standards of quality for required activities at Maine Yankee. Programmatic controls over work processes that were important to quality assured the proper qualification of QC inspectors and welders, the delegation of line responsibility for work quality, and the appropriate use of QC hold points and controls during maintenance planning and work control.

The Quality Assurance (QA) Program had a generally successful record of assessing the overall quality of station activities and identifying specific areas of vulnerability before performance degraded or the vulnerabilities became the subjects of regulatory enforcement. Annual audit and surveillance areas were selected using a weighted criterion of 11 factors that included safety, industry experience, regulatory impact, and power generation to assure that the most risk-sensitive areas are assessed. Most of the licensee's assessments were thoroughly performed and properly self-critical. For example, in 1994, the Quality Performance Department (QPD) identified and correctly characterized the problems with controlling the inputs to the safety analyses. However, the team identified a few areas as being adverse to quality which the licensee had not recognized as significant. Examples of such areas included the failure to identify components in the containment that were below submergence level in the Environmental Qualification (EQ) Program and the lack of complete testing of emergency core cooling system (ECCS) actuation logic.

Maine Yankee has effectively used outside organizations to characterize and objectively assess specific areas that had been identified by internal audits and assessments as requiring outside expertise. The licensee has commissioned at least 19 external assessments over the last three years that have often revealed aspects of the problem areas that eluded internal assessments. Recent examples of the successful use of outside assessment in areas which were first highlighted by QPD included audits of the Radiological Protection Organization by Westinghouse (1990), Cove's Edge Inc. (1995), and Millennium Engineering (1996).

The Cultural Assessment Team (CAT) Report (1996) was another example of the effective and timely use of outside experts to evaluate and characterize problems. This team of organizational psychologists and human factors specialists conducted an objective assessment of plant organizational culture in response to worker and management concerns. The overall finding was that the cultural atmosphere at Maine Yankee was "conducive to the raising of concerns perceived as safety significant, but is not conductive to forthright and prompt reporting for issues and concerns which are perceived to have little or no safety significance." When interviewed by the ISA team, most employees and managers expressed agreement with the findings and the recommendations of the CAT report. The licensee was developing an action plan to address the concerns and recommendations of the CAT report. Proposed actions included development of a new vision statement, increasing the Human Resources Section's presence on site, implementation of the Supervisory Improvement Program, and review of the End of Life Committee's

recommendations. Additionally, meetings were held with workers to emphasize the need to identify all problems.

Maine Yankee has made effective use of oversight committees to monitor the assessment process and to ensure that objective and independent views are presented to the Board of Directors. The Plant Operations Review Committee (PORC) effectively monitored such routine operational decisions as 10 CFR 50.59 reviews and procedure changes, and assessed how the licensee was handling unusual occurrence reports (UORs). The Nuclear Safety Audit and Review Committee (NSARC) functioned as the licensee's independent oversight board for all station issues. This committee was comprised of senior managers from Maine Yankee as well as outside experts from other utilities and experts from Yankee Atomic Electric Company (YAEC). Committee members effectively raised concerns as appropriate. NSARC members were observed to be actively involved in many assessment activities, including QA audit exit meetings and event reviews. However, the Chairman of the NSARC was also the Manager of QA for YAEC. In the latter position, he provided audit resources for Maine Yankee. As the Chairman of the NSARC, he was in charge of committee oversight of his department's work. This resulted in the appearance of a lack of independence. The Nuclear Oversight Committee consisted of outside experts who reported directly to the Board of Directors regarding high-level issues that impacted the industry.

The licensee used numerous performance indicators and managers met monthly to examine them and discuss their meaning. Although this process was a comprehensive effort, there were several key performance indicators that were under development and that had only two months of data, thus limiting the usefulness of trending the data at the time of the assessment. Tracking and reporting of many performance indicators was discontinued during the 1995 outage. Consequently, some managers stated that they saw little management benefit from many performance indicators and they were continuing to adjust their content and presentation to aid in use and interpretation.

The team found that performance indicators for the Maine Yankee Task Tracking System (MYTTS) did not reflect the significance of open items or identify late items. During the assessment, the licensee corrected this weakness when informed by the team. Performance indicators for maintenance work orders included only approximately 25 percent of the total number of outstanding work orders that were listed in the Maintenance Information and Parts Procurement System (MIPPS). For example, the indicator used to reflect corrective maintenance backlog contained only approximately 15 percent of the relevant action codes. Consequently, the total workload in the backlog was not accurately characterized by the performance indicator although the overall trend in the work off rate was representative.

The licensee's problem identification and tracking process consisted of approximately 29 individual systems. The fragmentation of the identification process was recognized by the licensee in several corrective action audits conducted over the past few years. Additionally, NRC Region I staff noted this issue in 1995. The licensee initiated the Learning Process Improvement Program to provide a plantwide methodology to integrate the separate tracking systems.

A review of approximately 4 years of data indicated that the existing problem identification systems such as the UORs and the safety issue concerns (SIC), were effectively highlighting station problems to managers. Management had recently emphasized the need to lower the threshold for problem identification in response to the Cultural Assessment Team Report and the December 1995 allegations. One indication of the effectiveness of this threshold change was the increase since the beginning of the year in the number of design bases screens (DBS). In 1994 the number of DBSs identified by the licensee was 12. The licensee had identified more than 50 issues in 1996.

Although the threshold for raising problems had decreased since the beginning of the year, the team found some examples where cultural barriers to problem identification still existed: for example, the poor foreign material controls for containment and the poor condition of the service water building. Additionally, the licensee had not recognized a number of significant equipment and program deficiencies. These deficiencies included the inappropriate safety system check valve testing, the numerous environmental qualification concerns, and the lack of complete safety system logic testing.

4.2 Corrective Actions

The team assessed the licensee's Corrective Action Program by evaluating the following areas: problem evaluation, problem resolution, and commitment tracking. Additionally, the team reviewed the licensee's new Learning Process, a program for improving corrective actions. The root cause evaluation process was generally effective; however, tracking of corrective actions was fragmented. Overall, the Corrective Action Program was weak and resulted in instances of untimely and ineffective corrective actions.

4.2.1 Problem Evaluation

The team reviewed the licensee's problem evaluation processes and determined that the Plant Root Cause Evaluation (PRCE) process and Human Performance Evaluation System (HPES), when used, were effective in identifying root causes and recommending corrective actions. The individuals performing the root cause evaluations were trained in various root cause determination methods. These methods were effectively used in the PRCEs reviewed by the team. Although the departmental root cause determinations were less detailed than the PRCEs, they appeared effective at addressing lower level problems.

The licensee's Quality Performance Department (QPD) performed trending on various root causes (PRCEs, HPESs, LERs, SICs, and Radiological Incident Reports), QPDs nonconformance reports (NCRs), and corrective action requests (CARs). This information was provided to management annually in the Functional Area Assessment Report (FAAR). The department level (Operations and Maintenance) root causes were not trended. However, radiological controls issues such as personnel contamination events were trended separately. The lack of departmental root cause trending combined with the infrequent FAAR trend data did not give management the information it needed to assess adverse trends. Timely trending could have identified continuing problems in the areas of foreign material exclusion control and auxiliary feedwater (AFW)

system reliability. The licensee's new Learning Process was designed to address this issue.

4.2.2 Problem Resolution

The team determined that the licensee's corrective action resolution process was weak. The licensee's tracking system was fragmented with approximately 21 individual systems. The backlog of corrective actions was relatively large and was increasing. Excluding work orders, there were approximately 1000 issues identified in the major tracking systems (CARs, Items for Investigation, and MYTTS). The other 17 systems had approximately 2200 items. The average age of the items was 8 to 9 months, and some items were as old as 10 years. The licensee did not determine the resource requirements to complete corrective actions, but developed scheduled completion dates for the items. The July 1996 MYTTS Report showed that 534 items were open. This included 184 commitment items of which 42 percent were late, and 157 operational experience report items of which 28 percent were late.

The licensee's 1995 corrective action audit also questioned the commitment of management to timely problem resolution. The team reviewed a number of corrective action items and determined that the licensee continued to be untimely in correcting some significant issues. One example was the untimely actions to address concerns with the undersized atmospheric steam dump valve which the licensee first identified in 1986. A second example was the Service Water System Operational Performance Inspection conducted by the licensee in 1994. The report contained nine recommendations. None of the recommendations had been closed out and three were overdue. Additionally, numerous follow-up items were still open. One item identified a turbine hall flooding issue which was scheduled to be addressed in June 1997. However, the April 1996 IPEEE findings showed that the plant was outside of its design basis for a turbine hall flood. This design issue could have been identified and resolved in 1994. A third example was the issue of the ventilation damper in the containment spray building. This issue was previously raised by Yankee Atomic in a 1991 memorandum, but had not been acted on by Maine Yankee.

Some of the licensee's corrective actions have been ineffective and have caused repetitive problems. An example of such ineffective corrective actions was the repetitive problems with the AFW control system and the continuing problem with the main feedwater pump P-2B tripping on low lube oil pressure. An example of inadequate corrective action was how the licensee addressed the negative control room pressure identified during a surveillance conducted in October 1995.

The team reviewed the licensee's commitment tracking performance and found that the current commitment tracking system was good because of recent changes. In the April 1996 "RELAP/5YA Self Assessment Report," the licensee identified fragmented commitment tracking systems as a contributing cause. In response, the licensee adopted guidance outlined in the Nuclear Energy Institute's "Guideline for Managing NRC Commitments," dated December 19, 1995. In addition, the licensee reviewed earlier documentation to verify the inclusion of all commitments. At the close of the assessment, the licensee had reviewed all applicable documents for the preceding 5 years.

In response to self-identified concerns, the licensee developed an integrated Corrective Action Program, the Learning Process, which was scheduled for implementation in the fall of 1996. The development of the Learning Process was a reengineering effort which involved a team approach. The objectives were to integrate the processes of problem identification, problem prioritization, root cause evaluation, problem tracking and resolution, and to develop a more useful trending process. The new system was designed to be a computer-based system. At the close of the assessment, the licensee was developing the implementing procedures and necessary training.

4.3 Planning And Resources

Licensee planning was effective; however, weaknesses were identified in planning integration and improvement plan implementation. Economic pressures, which resulted in limitations on resources, interfered with the licensee's ability to complete projects and other efforts that would bring improvements to plant safety and testing activities. Equipment problems were not resolved and improvement programs were not effectively implemented because the licensee perceived them to be of low safety significance.

4.3.1 Plans

The licensee did not have an integrated overall planning document. While many elements of an integrated plan existed, none of these elements contained information which identified required resources to achieve specified goals and objectives. Additionally, specific performance measurements to determine the level of accomplishment were not included. The licensee had independently identified the lack of an integrated overall plan and was in the process of incorporating the fragmented elements into a single document as part of the Business Plan Initiative and Executive Management Initiatives improvement plans.

Licensee work planning was organized and effective. On average, 80 to 90 percent of planned work was accomplished on the day scheduled. An additional strength of the planning process was the use of risk measurements to aid in timing of equipment and system outages and to increase employee awareness. Outage planning was also organized and effective. The licensee used state-of-the-art computer planning aids and incorporated risk measurements into the overall outage plan. The licensee effectively incorporated industry guidance for shutdown risk management into the work planning process.

The licensee had a number of improvement plans for various purposes. Improvement plans included the Learning Process described earlier, the Maintenance Improvement Program (including a Procedure Adherence Initiative), the Engineering Quality Improvement Program, the Safety Analyses Improvement Plan, and the Supervisory Improvement Plan (a personnel training program). These programs were well thought out, adequately documented, and promulgated to the appropriate staff.

Some past improvement programs were successful; for example, the licensee's efforts to improve industrial safety performance. In April 1996, all maintenance work was stopped in response to industrial safety concerns

identified by licensee management. Several days were then dedicated to discussing and highlighting industrial safety prior to resumption of work. This action, coupled with continuing emphasis on industrial safety issues resulted in reductions in industrial safety hazards and lost time injuries. The team observed good industrial safety performance during the assessment. The team also found that some previous improvement plans were not effective. For example, beginning in 1990, the licensee initiated several improvement plans to correct problems in the Radiation Protection Department. Despite these attempts at improvement, problems continued to repeat themselves. Some improvement plans had not been accomplished because of lack of funding. For example, the improvement initiatives associated with implementing a comprehensive air-operated valve (AOV) testing program had not been funded for the past 3 years and the Erosion Control Program was not fully funded for 1995. Also, some programs had received funding, but the licensee had discontinued them during times of resource stress. For example, the Supervisory Improvement Program was discontinued during the 1995 refueling outage.

4.3.2 Economic Environment

Like all licensees, the Maine Yankee Atomic Power Company (MYAPCo) has experienced competitive pressure to generate power at low cost. However, unlike others, Maine Yankee has not engaged in drastic staff reductions, work process reengineering or other budget cutback efforts to maintain competitiveness because it has historically maintained a lean and efficient organization. Staffing levels and budget expenditures have been constrained to that necessary to generate power efficiently.

The MYAPCo owners comprise 10 utilities in the New England region. The largest single owner, Central Maine Power (CMP), owns 38 percent of the company. Northeast Utilities, in combination with other subsidiaries, owns approximately 20 percent of the company. The balance of the owners consist of other New England utilities.

The owners have exclusive rights to the power that is generated by the plant in proportion to their equity share. They are also required to provide for the operating and capital expenses to produce this power. The owners do not directly purchase the power from MYAPCo. Instead, they funded the approved budget and cover any unexpected funding requirements in proportion to their share in equity. The owners can pass along their respective share of prudent operating costs to their rate payers.

The cost of producing power at Maine Yankee is lower than for most other base load power in the area. Maine Yankee has the capacity to produce approximately 50 percent of the power in the State of Maine at a wholesale cost of 2.5 to 3.5 cents per kilowatt-hour. However, due to ownership shares, approximately 25 percent of the total power in the State of Maine is actually generated by Maine Yankee, and the remainder of the power is exported to out-of-state owner utilities. The owners have established multi-year contracts to resell approximately six to seven percent of the power produced by Maine Yankee to other utilities.

Senior plant management maintains control over the capital and operating budgets by setting budget targets and monitoring expenditures. The budget targets are constrained by Federal Energy Regulatory Commission (FERC) regulations and are required to be justified as needed and as reasonable. One of the criteria used by the FERC process to establish the rate for wholesale power is the avoided cost of power on the grid.

The rate structure in Maine was established by the Maine Public Utility Commission in December 1994, and constrains CMP to a multi-year Alternative Rate Plan (ARP) agreement which explicitly caps the cost of retail power to customers throughout the State. In addition, CMP signed a series of long-term power contracts with smaller independent power producers (IPPs) and non-utility generators (NUGs) with wholesale rates that were previously set between 9 and 11 cents per kilowatt-hour. This combination of multi-year high-cost power contracts and ARP retail rate caps effectively forces CMP to balance the conflicting objectives by mitigating the higher cost of power from the numerous NUGs and IPPs in their service area with low-cost power from Maine Yankee.

4.3.3 Results Of Resource Constraints

Unlike most utilities, MYAPCo does not retain earnings and does not set asside reserve funds for unplanned requirements, except those required by law. All monies in excess of operational expenses are periodically returned to the owners. The owner utilities are required to either capitalize or immediately finance emergent requirements from their operating budgets. The 1995 steam generator sleeving project is an example of an unplanned requirement at the plant causing severe financial impact to several owners. In order to respond to the immediate cash requirements, MYAPCo imposed a 10-percent reduction in operating and maintenance (O&M) costs across the board and terminated all outside contract labor on site. Except for the decommissioning fund, the nuclear waste trust funds, and pension funds which were mandated by law, the organization did not set aside reserve capital funding to provide for emergent needs.

MYAPCo used a sophisticated financial model to determine the cost factors that could encourage large industrial customers to elect to generate their own power and erode the mix between industrial and residential users. These factors combined to internally constrain the utility budget targets to reflect the competitive position of the regional spot market for power which were even lower than the cost factors listed above. In summary, Maine Yankee produced some of the least expensive power in the New England region and the regional utilities in Maine had limited budget funding to offset higher costs and competitive pressures.

Management has effectively operated the plant within the budget constraints established by the owners. However, the limitations on resources have delayed and deferred plant upgrades, improvements, and lower priority corrective actions which did not meet the threshold for safety, regulatory compliance, or reliable production. Projects which would likely have prevented problems were unfunded because of budget limits.

One illustrative example was the imposed delay of the completion of the Safety Analyses Inputs Document (SAID) which could have re-identified the problem with the undersized ASD sooner. The SAID project was the corrective action to prevent loss of control over the safety analyses inputs in response to concerns first documented in 1994 by the Nuclear Engineering Department and QPD. Development of the SAID was substantially delayed in 1995 when the steam generator sleeving project required the redirection of engineering resources. A request from the Corporate Engineering Department (CED) in the 1995 budget request to add an additional engineer to continue the SAID development was not funded by the senior plant management.

Another example of a case in which limited resources interfered with performance was the decision not to implement a comprehensive AOV testing program. In 1995, the Maintenance Department proposed to implement the testing program and to procure a diagnostic testing system for AOVs. The consequence of not funding the effort was stated in the unfunded O&M budget list as "continue to work on AOVs on an 'as fail' basis (reactive) rather than predictive maintenance." Despite these words of caution and a strong justification to proceed, management did not authorize the $218,000 needed to correct this problem because the testing system was not explicitly required by NRC regulations. If implemented, this testing system could have detected and prevented some of the AOV problems identified elsewhere in this report.

Another example of deferring needed projects because of a lack of funding is the halting of the mechanical/electrical/I&C specialty training program during the 1995 steam generator sleeving outage. This training prepared maintenance workers as journeymen and provided continuing proficiency training. All specialty training was halted in an effort to increase the availability of maintenance workers to support outage work. Additionally, funds were not approved in the 1995 O&M budget to respond to industry reaccreditation issues.

Another example of the impact of limited resources on important projects was that the design-basis summary program was halted during the 1995 steam generator sleeving outage because of constraints on staff resources. If this program had continued, there would have been additional opportunities during the development of design-basis documents to identify some of the older design problems that were later identified by the team.

In addition, approximately 100 high priority work orders were deferred from the 1995 outage schedule at the end of the outage because of schedule constraints. With maintenance work order and corrective action tracking system backlogs increasing, senior plant management has recently decided to add more staff.

5.0 CONCLUSIONS

The conclusions drawn from this assessment and the underlying root causes for the significant safety findings follow.

5.1 Licensing And Design-Basis

Maine Yankee was in general conformance with its licensing-basis although significant items of non-conformance were identified. The licensing-basis was understood by the licensee but lacked specificity, contained inconsistencies, and had not been well maintained.

The use of analytic codes for safety analyses was very good. Cycle specific core performance analyses were excellent. More complicated, less frequently performed safety analyses contained weaknesses, but the analyses were found to be acceptable based on compensating margin. Conditions of use specified in the safety evaluation reports were found to be satisfied, but not documented.

The quality and availability of design-basis information was good overall. Despite uncorrected and previously undiscovered design problems, the design-basis and compensatory measures adequately supported plant operation at a power level of 2440 MWt. However, the team could not conclude, and the licensee did not demonstrate, that the design-basis supported operation at 2700 MWt relative to assuring adequate NPSH for the containment spray pumps and for the heat removal capability of the PCCW and SCCW systems.

5.2 Operational Safety

5.2.1 Operations

Overall performance in the area of operations was very good. Strengths were noted in the areas of operator performance during routine and transient operating conditions; shift turnovers and pre-evolution briefs; use of risk information to ensure safe operations; and the involvement of management in day-to-day operations. Weaknesses were noted in the area of "workarounds" and compensatory measures which unnecessarily burdened the operators or complicated their response to transient conditions. Additionally, log-keeping practices and post-trip reviews lacked rigor.

5.2.2 Maintenance And Testing

Performance in the area of maintenance was good overall however, testing was weak. The results of the review of equipment reliability for the auxiliary feedwater, emergency feedwater, high pressure safety injection, and emergency diesel generator systems showed mixed equipment performance. Strengths were noted in the areas of knowledge and use of risk methodologies for planning, prioritizing, and scheduling work; the control and limited use of temporary sealants; and a motivated and dedicated work force. Although material condition was considered good overall, a number of significant material condition deficiencies were noted as was a decline in material condition following the 1995 steam generator tubing outage.

Inadequacies in the scope of testing programs were identified, as were weaknesses in the rigor with which testing was performed and the evaluation of testing results to demonstrate functionality of safety equipment. A lack of a questioning attitude and stressed resources resulted in the use of poor surveillance procedures and ineffective evaluation of surveillance test data.

5.2.3 Engineering

The quality of engineering work was mixed but considered good overall. Strengths were noted in the capability and experience of the engineering staff, day-to-day engineering support of maintenance and operations, in the quality of most calculations, and in the routine use and application of analytic codes. However, engineering was stressed by a shortage of resources, and there was a tendency to accept existing conditions. Specific weaknesses were noted with inconsistent identification and resolution of problems, inadequate testing, and work on some calculations and analytic codes.

5.3 Root Causes Of Significant Findings

Overall performance at Maine Yankee was considered adequate for operation of the facility. However, a number of deficiencies were identified by the team in each of the areas assessed. These deficiencies, which included weak identification and resolution of problems; inadequate scope, and weak rigor and evaluation of testing; and declining material condition stemmed from two closely related root causes.

5.3.1 Root Cause 1: Economic Pressure

Economic pressure to be a low-cost energy producer has limited available resources to address corrective actions and some plant improvement upgrades. Management has effectively prioritized available resources, but financial pressures have caused the postponement of some needed program improvements and actions.

The economic pressures discussed in Section 4.3 resulted in limitations on resources and interfered with the licensee's ability to complete projects and other efforts that would improve plant safety and testing activities. Examples include the failure to adequately test safety related components (Section 3.2.4); the long-standing deficient design conditions, such as the undersized atmospheric steam dump valve (Sections 3.1.3.1 and 3.3.1) and environmental qualification issues (Section 2.3.9); and the lack of effective improvement programs, such as the design basis reconstitution program (Sections 3.3.3 and 4.3.3). These and other examples discussed in the report illustrate the licensee's willingness to accept existing conditions, many of which became operator workarounds (Section 3.1.1.1).

5.3.2 Root Cause 2: Problem Identification

There is a lack of a questioning culture which has resulted in the failure to identify or promptly correct significant problems in areas perceived by management to be of low safety significance. Management appears complacent

with the current level of safety performance and there does not appear to be a clear incentive for improvement.

Examples of issues which illustrate complacency and the failure to identify or promptly correct significant problems, include previously undiscovered deficient conditions of the service water and auxiliary feedwater water systems (Section 3.2.2); inadequacies in ventilation systems (Section 2.3.7); post-trip reviews which lacked rigor and completeness (Section 3.1.2.7); emergency operating procedures that may not adequately address an inadequate core cooling event and a steam generator tube rupture under certain conditions (Section 3.1.3.1); lack of a questioning attitude during test performance and evaluation that was not conducive to discovering equipment problems, but rather to accepting equipment performance (Sections 2.2.1, 3.2.2, 3.2.4); and licensee self-assessments that occasionally failed to identify weaknesses, or incorrectly characterized the significance of findings (Section 4.1). In addition, some corrective actions were not timely and others were ineffective, leading to repetitive problems (Section 4.2).

6.0 REGULATORY ISSUES

During the course of this assessment, a number of deficiencies were identified for which the NRC shares some responsibility. Certain of these deficiencies are identified here and will be developed and addressed as part of a separate NRC followup effort on the lessons learned from the Maine Yankee Independent Safety Assessment.

6.1 Analytic Code Validation

The ISA team noted that the validation of RETRAN to known industry benchmarks for integral and separate effects test data was deficient. This validation is important to assure that the plant-specific application of the code effectively models known physical effects; however, the requirement for this validation was vague. The requirement can be traced to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Action," issued on February 8, 1993, which states in part:

> ... some licensees planning to perform their own safety analyses may not intend to demonstrate their ability to use the code by performing their own code verification. Rather, they plan to rely on the code verification work previously performed by the code developer or others.
>
> NRR does not consider this acceptable and each licensee or vendor who intends to use a safety analysis computer code to support licensing actions should demonstrate their proficiency in using the code by submitting code verification performed by them, not others.

The NRC has acted inconsistently relative to its expectations in this area. In some cases, computer codes have been endorsed for use with little or no validation accomplished. The NRC should review its expectations relative to validation and assure they are made clear to the industry.

6.2 Compliance With Safety Evaluation Reports

During the Maine Yankee ISA, compliance with conditions imposed on the use of analytic codes was verified for 67 SER conditions affecting 13 codes. Although compliance was confirmed, an audit trail to assure compliance was not always available, necessitating, in some cases, additional analyses to verify compliance.

The regulatory status of an SER imposed commitment is unclear and should be reviewed. If conditions within an SER are considered appropriate, clear NRC expectations relative to compliance, auditability, and reportability should be established.

6.3 Licensing Reviews For Power Uprates

The Maine Yankee ISA team identified a number of mechanical components for which confirmation of operability at the upgraded power level of 2700 MWt

could not be confirmed. The NRC should review the scope and rigor of the licensing reviews conducted for power uprates.

6.4 Safety Guide 1

NRC Safety Guide 1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps" issued on November 2, 1970, states,

> NPSH for emergency core cooling and containment heat removal system pumps caused by increases in temperature of the pumped fluid under loss of coolant accident conditions can be accommodated without reliance on the calculated increase in containment pressure."
>
> Emergency core cooling and containment heat removal systems should be designed so that adequate net positive suction head is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated loss of coolant accidents.

The NRC should review and clarify its intent relative to relying on containment pressure for assuring appropriate NPSH for emergency core cooling and containment heat removal pumps. Specifically, the issue of whether or not the containment can be assumed to be pressurized at the saturation pressure for the sump fluid temperature should be addressed.

6.5 Inspection Program

The adequacy of the scope and implementation of the NRC inspection program should be reviewed in the following areas:

- the licensee-implemented testing programs for safety systems relative to its scope, rigor, and analyses of results
- the periodic review of licensee developed Technical Specification interpretations to assure consistency with the intent of the approved Technical Specifications
- assessment of the adequacy of the plant design-basis including a review of the disposition of significant findings from previous licensee efforts such as design-basis documentation or design-basis reconstitution programs.

7.0 EXIT MEETINGS

Two interim exit meetings were held during the course of this assessment. The first was held on July 26, 1996, at the end of the first two week onsite assessment period, and the second was held on August 23, 1996, at the end of the second and final onsite assessment period. The purpose of the interim exit meetings was to provide an opportunity for the ISA team leader and functional area leaders to provide an integrated discussion of the assessment findings to date.

A final meeting, open for public observation, will be held with Maine Yankee representatives at the Wiscasset Middle School, Wiscasset Maine on October 10, 1996. The conclusions of the report will be discussed at this meeting.

ABBREVIATIONS

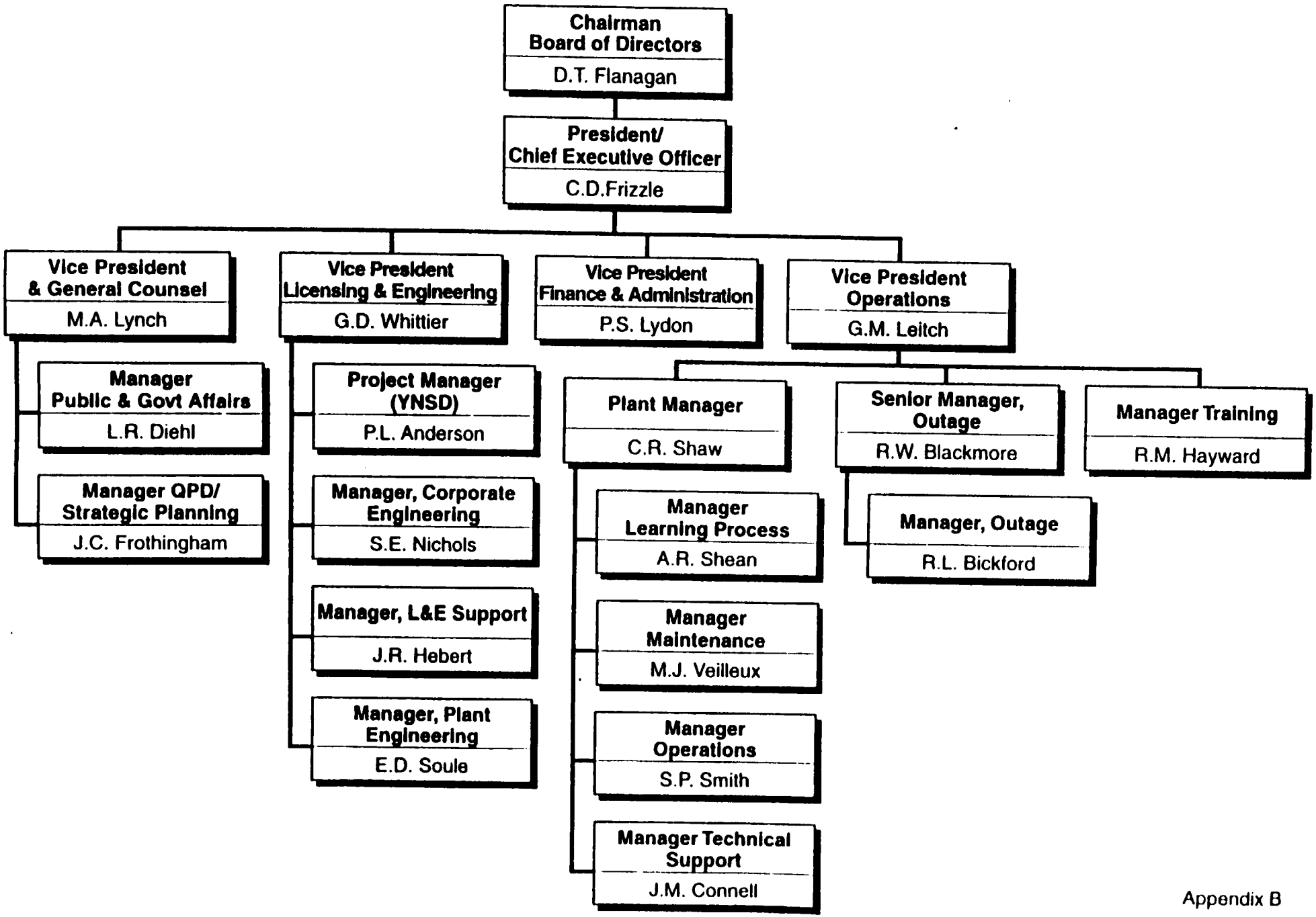
AEOD	Office for Analysis and Evaluation of Operational Data (NRC)
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AOV	air-operated valve
ARP	alternative rate plan
ASD	atmospheric steam dump
BIRP	Boron Injection RETRAN Post-processor
CAL	confirmatory action letter
CAR	corrective action request
CAT	cultural assessment team
CCW	component cooling water
CDF	core damage frequency
CEA	control element assembly
CED	Corporate Engineering Department
CMP	Central Maine Power
CR	control room
CRO	Control Room Operator
CS	containment spray
CWPH	circulating water pump house
DBA	design-basis accident
DBI	design-basis information
DBS	design-bases screen
DBSD	design-basis summary document
DBR	design basis recovery
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DP	differential pressure
E/C	erosion/corrosion
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFW	emergency feedwater
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
EQ	environmental qualification

FAAR	functional area assessment report
FERC	Federal Energy Regulatory Commission
FME	foreign material exclusion
FP	fire protection
FPIP	Fire Protection Improvement Plan
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GL	generic letter
HELB	high-energy line break
HFP	hot full power
HI	Hydraulic Institute
HPES	human performance evaluation system
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger
IASD	Inputs and Assumptions Source Document
I&C	instrumentation and controls
ICC	inadequate core cooling
ILRT	integrated leak rate test
IN	information notice
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of Externally Initiated Events
IPP	independent power producer
ISA	Independent Safety Assessment
IST	inservice testing
LBLOCA	large-break loss-of-coolant accident
LER	licensee event report
LLRT	local leak rate test
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPSI	low-pressure safety injection
MCC	motor control center
MDFW	motor-driven main feedwater
MIPPS	maintenance information and parts procurement system
MOV	motor-operated valve
MSLR	main steam line rupture
MSR	moisture separator reheater
MWd/MTU	megawatt day per metric ton uranium
MYAPCo	Maine Yankee Atomic Power Company
MYAPS	Maine Yankee Atomic Power Station
MYTTS	Maine Yankee Task Tracking System

NCR	nonconformance report
NPSH	net positive suction head
$NPSH_A$	net positive suction head available
$NPSH_R$	net positive suction head required
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation (NRC)
NSARC	Nuclear Safety Audit and Review Committee
NUG	non-utility generator
OIG	Office of the Inspector General (NRC)
OLSA	online safety assessment
O&M	operating and maintenance
PCCW	primary component cooling water
PED	Plant Engineering Department
PORC	Plant Operation Review Committee
PRA	probabilistic risk assessment
PRCE	plant root cause evaluation
PSS	Plant Shift Superintendent
PTR	post-trip review
PWR	pressurized-water reactor
QA	quality assurance
QC	quality control
QPD	Quality Performance Department
RAS	recirculation actuation signal
RCP	reactor coolant pump
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RPS	reactor protection system
RWST	refueling water storage tank
SAID	Safety Analysis Information Document
SALP	systematic assessment of licensee performance
SAS	safety-actuation signal
SCCW	secondary component cooling water
SCU	Statistical Combination of Uncertainties
SER	safety evaluation report
SFP	spent fuel pool
SG	steam generator
SGTR	steam generator tube rupture
SIAS	safety injection actuation signal
SIC	safety issues concerns
SOS	Shift Operating Supervisor
SSA	shutdown safety assessment
STA	Shift Technical Advisor
SW	service water
SWOPI	service water operational performance inspection

T/H	thermal-hydraulic
TS	Technical Specification
UOR	unusual occurrence report
WO	work order
YAEC	Yankee Atomic Electric Company

MAINE YANKEE ATOMIC POWER COMPANY



APPENDIX C

EQUIPMENT PERFORMANCE FOR AUXILIARY FEEDWATER, EMERGENCY FEEDWATER, HIGH PRESSURE SAFETY INJECTION, AND EMERGENCY DIESEL GENERATOR SYSTEMS FROM JANUARY 1, 1992 THROUGH JUNE 30, 1996

Figure 1

Maine Yankee Independent Safety Assessment Team

Emergency Feedwater Pump Train P-25A - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

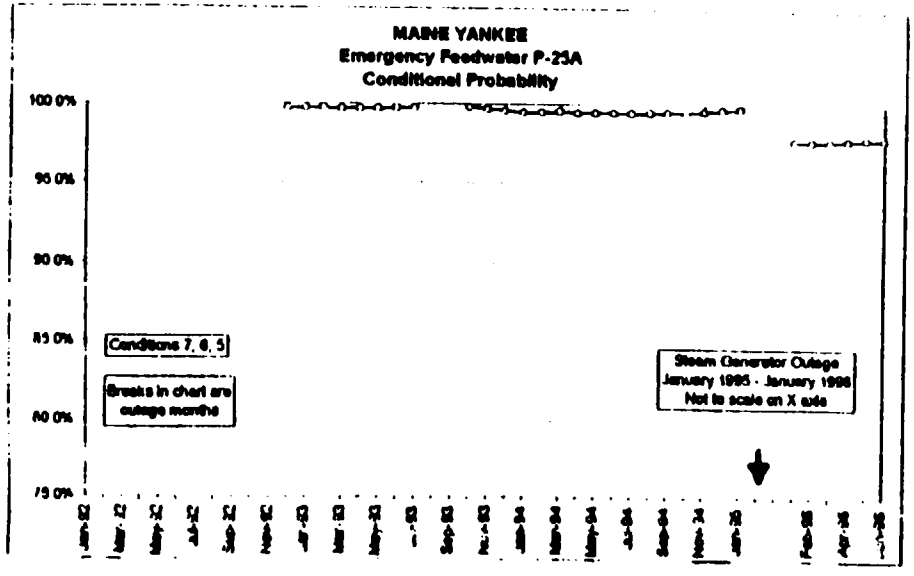
These curves represent the probability that the emergency feedwater (EFW) pump train P-25A will respond to a random demand, during power operations, for injection into the steam generators and will start and will inject into the steam generators for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

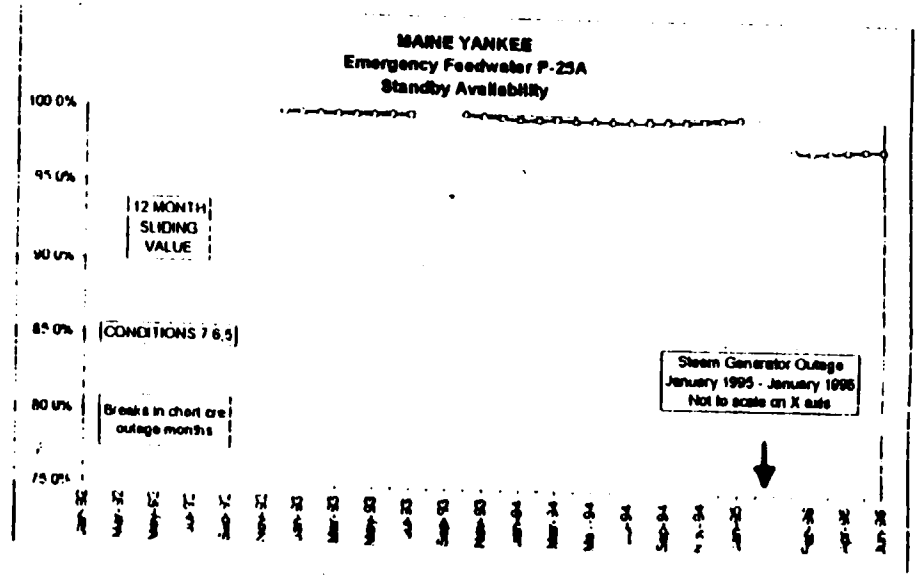
The conditional probability curve shows a very high value (over 99 percent) until January 1996. On January 8, 1996, the pump was placed in maintenance to repair a bearing oil leak and stayed in maintenance for 143.5 hours. Therefore the standby availability dropped in January 1996 with a resultant drop in the conditional probability. There have been no failures to start or failures to run of the pump train over the time period.

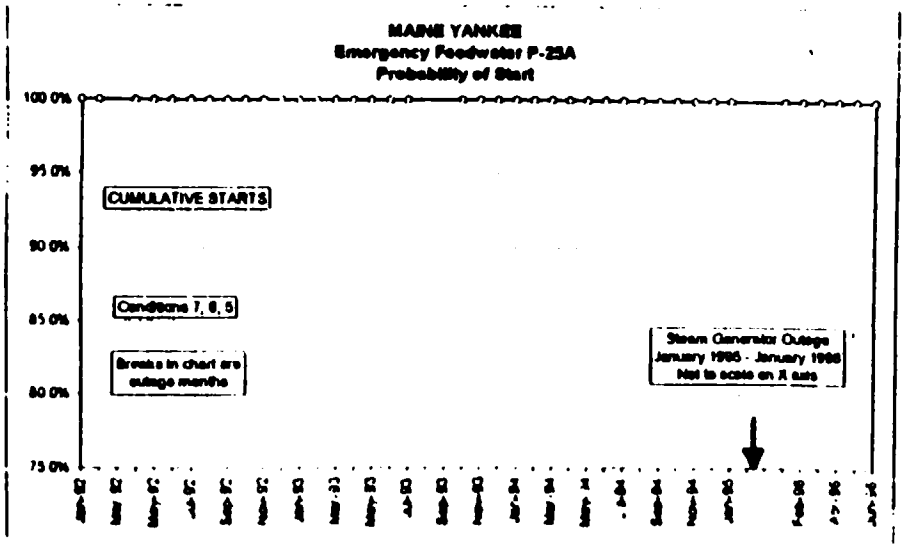
The value of the conditional probability as of June 30, 1996, was 97.9 percent. Thus it is expected that the EFW pump train P-25C would complete its mission approximately 98 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	130
Successful Starts	130
Failures to Start	0
Total Run Hours	487
Run Failures	0
Planned Maintenance Hours	44.5
Unplanned Maintenance Hours	143.5


MAINE YANKEE
Emergency Feedwater P-25A
Conditional Probability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
Emergency Feedwater P-25A
Standby Availability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
Emergency Feedwater P-25A
Probability of Start
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

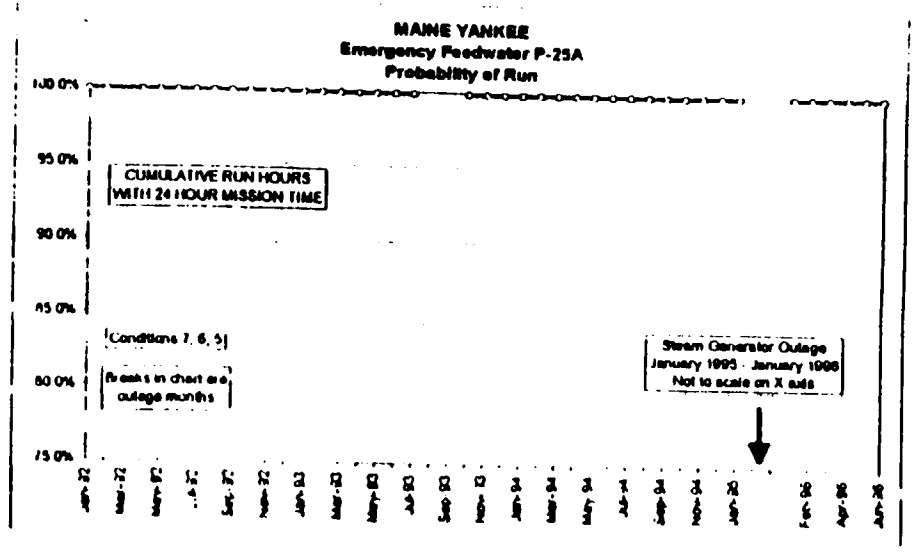

MAINE YANKEE
Emergency Feedwater P-25A
Probability of Run
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
CUMULATIVE RUN HOURS WITH 24 HOUR MISSION TIME
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

Figure 2

Maine Yankee Independent Safety Assessment Team

Emergency Feedwater Pump Train P-25C - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

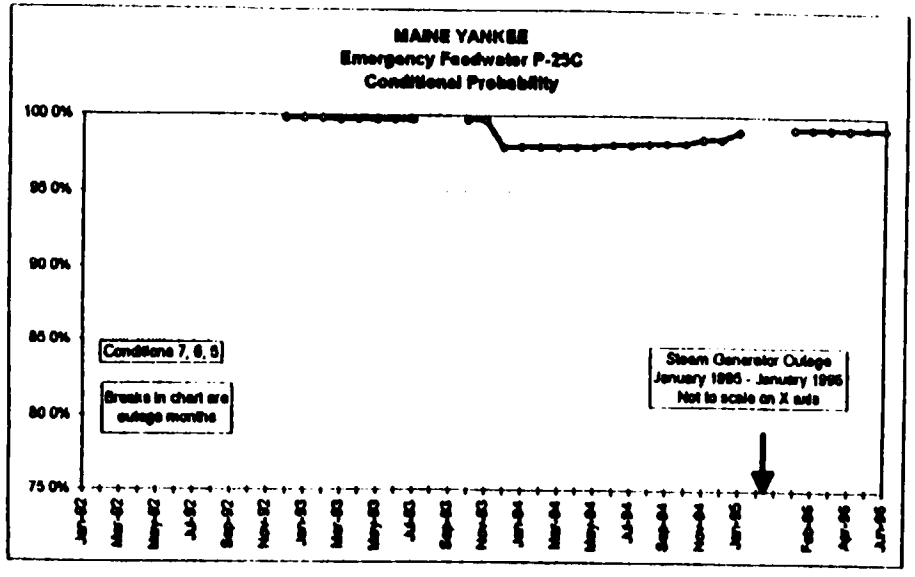
These curves represent the probability that the emergency feedwater (EFW) pump train P-25C will respond to a random demand, during power operations, for injection into the steam generators and will start and will inject into the steam generators for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

The conditional probability curve shows a very high value (over 99 percent) until December 1993. On December 6, 1993, the pump failed to start due to problems with a breaker for the pump. Therefore the probability of start dropped in December 1993 with a resultant drop in the conditional probability. There have been no failures to run of the pump train over the time period.

The value of the conditional probability as of June 30, 1996, was 99.2 percent. Thus it is expected that the EFW pump train P-25C would complete its mission approximately 99 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	192
Successful Starts	191
Failures to Start	1
Total Run Hours	992
Run Failures	0
Planned Maintenance Hours	29.5
Unplanned Maintenance Hours	1.5


MAINE YANKEE
Emergency Feedwater P-25C
Conditional Probability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
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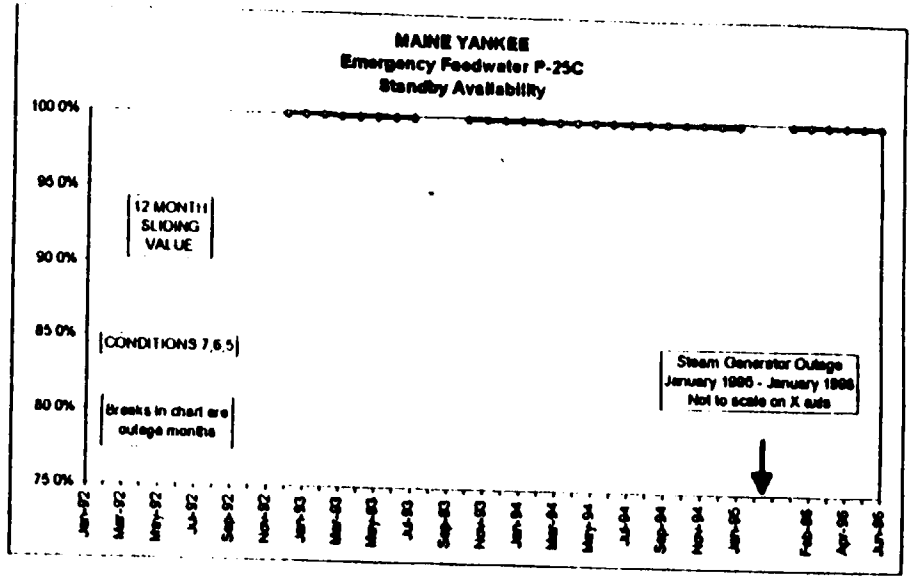
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95


MAINE YANKEE
Emergency Feedwater P-25C
Standby Availability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
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Jul-94
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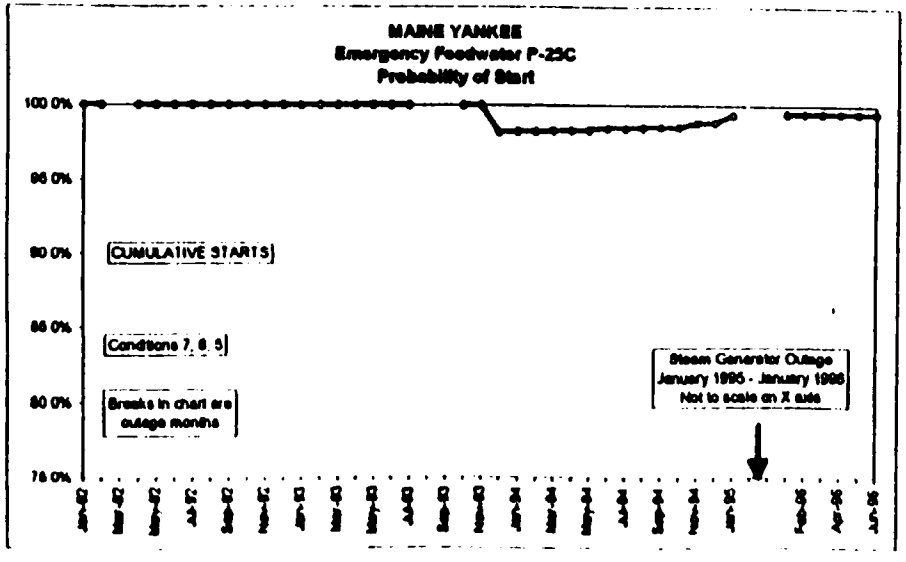
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95


MAINE YANKEE
Emergency Feedwater P-25C
Probability of Start
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95

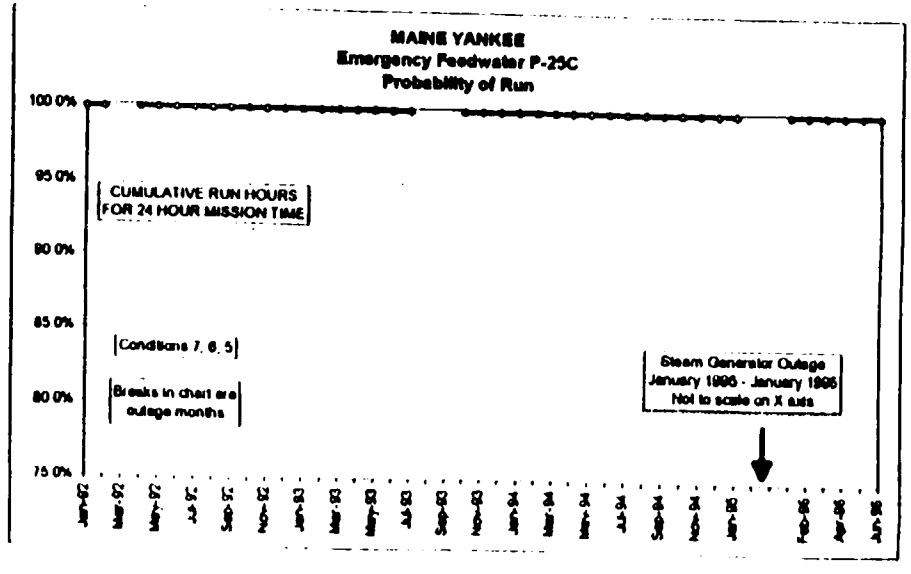

MAINE YANKEE
Emergency Feedwater P-25C
Probability of Run
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
CUMULATIVE RUN HOURS FOR 24 HOUR MISSION TIME
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95

Figure 3

Maine Yankee Independent Safety Assessment Team

Auxiliary Feedwater Pump Train P-25B - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

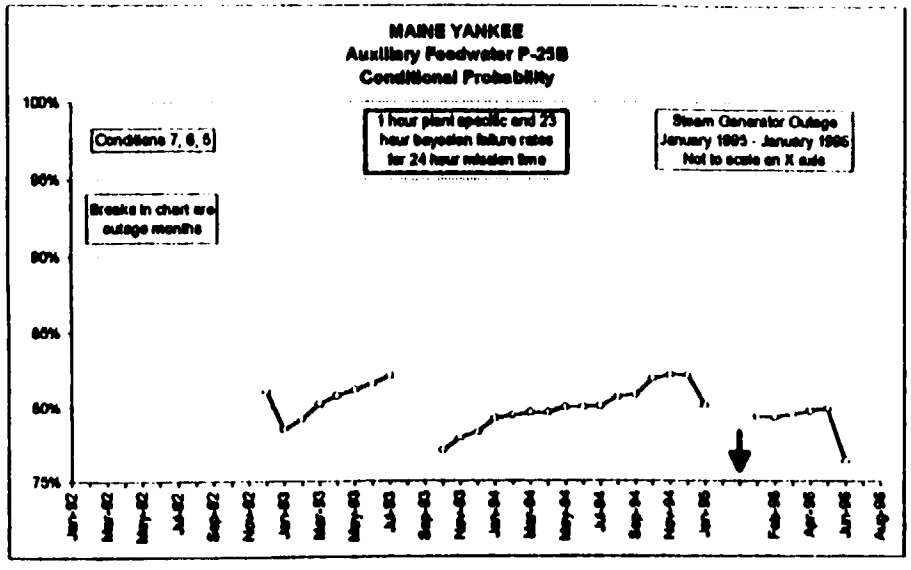
These curves represent the probability that the auxiliary feedwater (AFW) pump train P-25B will respond to a random demand, during power operation, for injection into the steam generators and will start and will inject into the steam generators for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

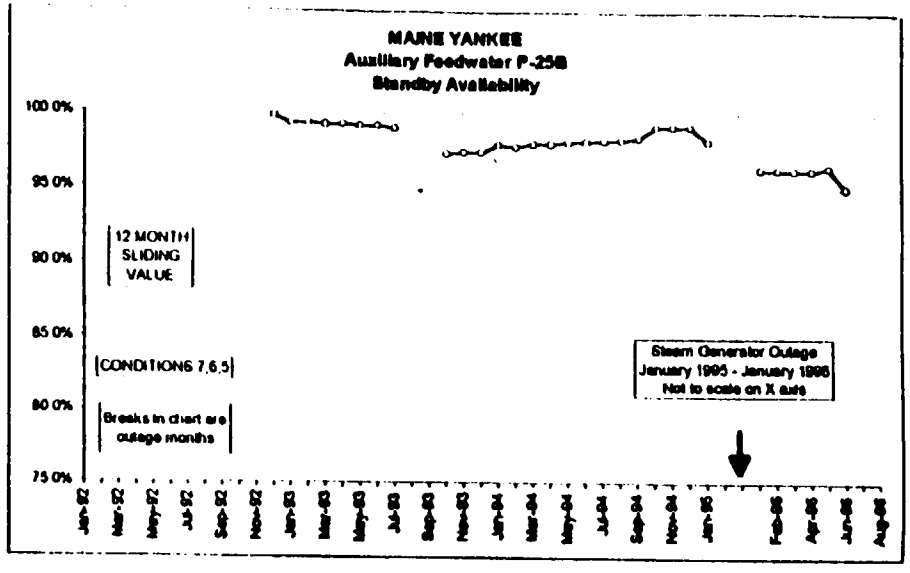
The conditional probability curve shows a very low value over the time period. There have been two failures to start and three failures to run over time period. The standby availability has been steadily dropping over the time period because of the time spent to repair failures.

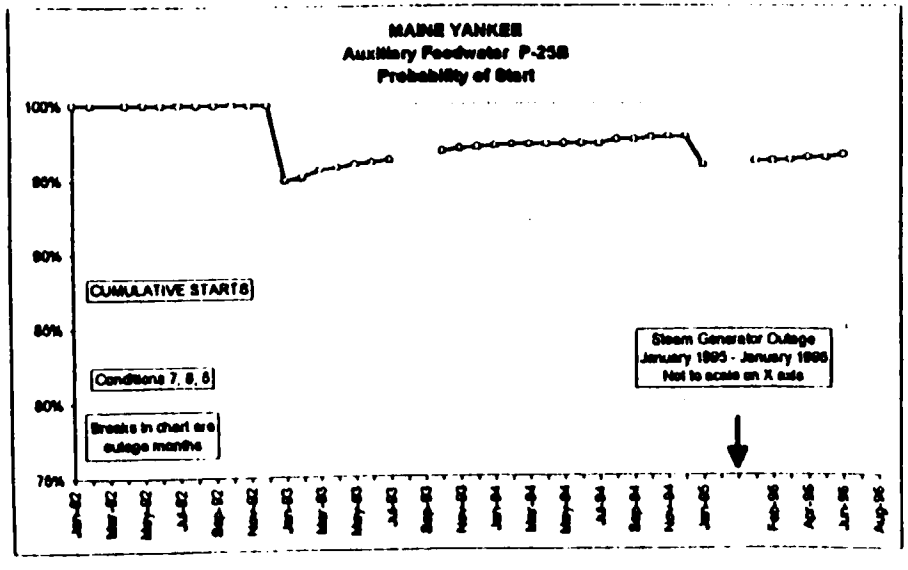
The value of the conditional probability as of June 30, 1996, was 76.3 percent. Thus it is expected that the AFW pump train P-25B would complete its mission approximately 76 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	59
Successful Starts	57
Failures to Start	2
Total Run Hours	26.5
Run Failures	3
Planned Maintenance Hours	132.5
Unplanned Maintenance Hours	441.0


MAINE YANKEE
Auxiliary Feedwater P-25B
Conditional Probability
Conditions 7, 6, 5
Breaks in chart are outage months
1 hour plant specific and 23 hour bayesian failure rates for 24 hour mission time
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
100%
95%
90%
85%
80%
75%


MAINE YANKEE
Auxiliary Feedwater P-25B
Standby Availability
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%


MAINE YANKEE
Auxiliary Feedwater P-25B
Probability of Start
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
100%
95%
90%
85%
80%
75%

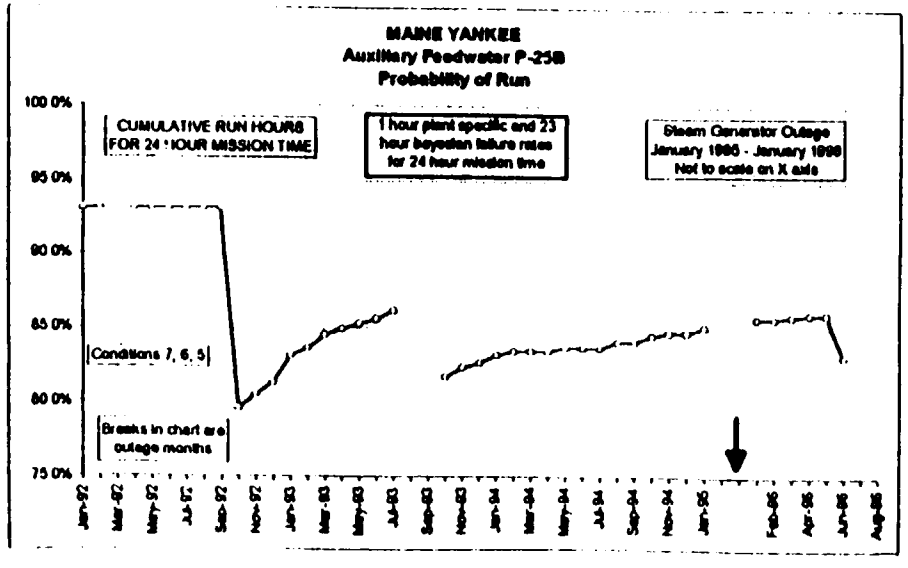

MAINE YANKEE
Auxiliary Feedwater P-25B
Probability of Run
CUMULATIVE RUN HOURS FOR 24 HOUR MISSION TIME
1 hour plant specific and 23 hour bayesian failure rates for 24 hour mission time
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
Conditions 7, 6, 5
Breaks in chart are outage months
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%

Figure 4

Maine Yankee Independent Safety Assessment Team

High Pressure Safety Injection Pump Train P-14A - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

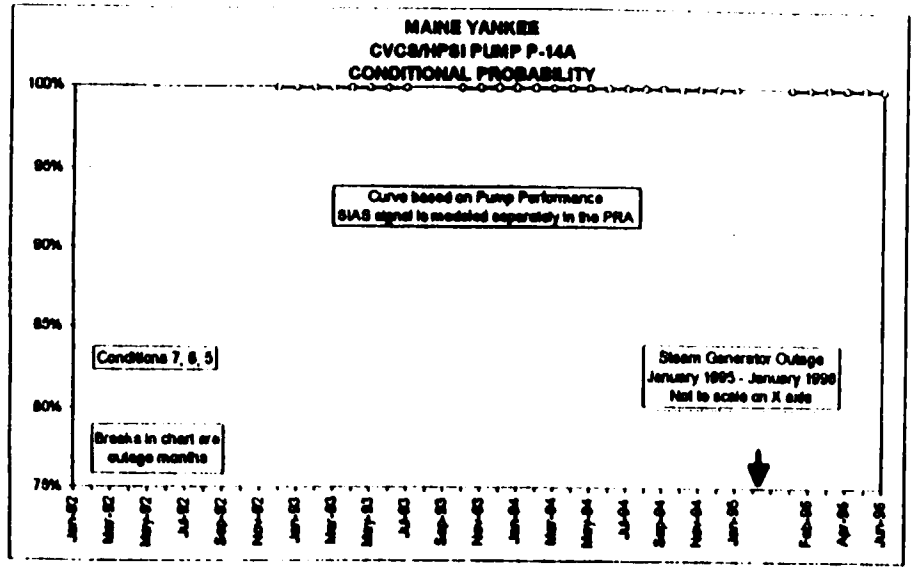
These curves represent the probability that the high pressure safety injection (HPSI) pump train P-14A will respond to a random demand, during power operation, for injection into the reactor vessel and will start and will inject into the reactor vessel for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

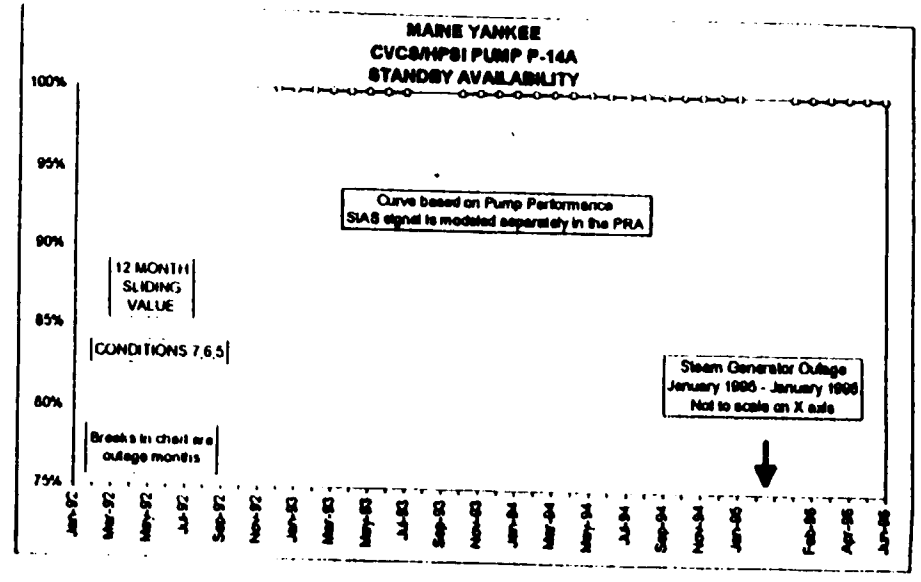
The conditional probability curve shows a very high value (over 99 percent). Thus it is expected that the HPSI pump train P-14A would complete its mission approximately 100 out of 100 random demands.

During the course of the independent safety assessment team evaluation, it was discovered that there was a missing wire (had been inadvertently removed) in the safety injection actuation system (SIAS) logic which would have prevented P-14A from starting if P-14A were the "alternate pump" during power operation. This failure was not included in the conditional probability of pump train P-14A, but rather was included in the failure of the SIAS logic in the Maine Yankee Individual Plant Examination.

For the curves, high values are better than low values.

Total Starts	79
Successful Starts	79
Failures to Start	0
Total Run Hours	9.996
Run Failures	0
While aligned	
Planned Maintenance Hours	4.4
Unplanned Maintenance Hours	0.5


MAINE YANKEE
CVCS/HPSI PUMP P-14A
CONDITIONAL PROBABILITY
100%
95%
90%
85%
80%
75%
Curve based on Pump Performance
SIAS signal is modeled separately in the PRA
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95


MAINE YANKEE
CVCS/HPSI PUMP P-14A
STANDBY AVAILABILITY
100%
95%
90%
85%
80%
75%
Curve based on Pump Performance
SIAS signal is modeled separately in the PRA
12 MONTH
SLIDING
VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
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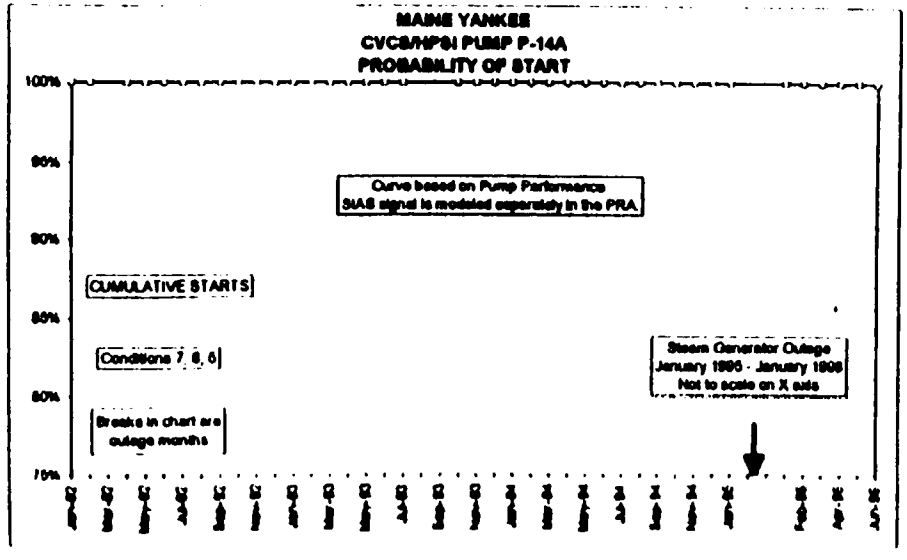
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95


MAINE YANKEE
CVCS/HPSI PUMP P-14A
PROBABILITY OF START
100%
95%
90%
85%
80%
75%
Curve based on Pump Performance
SIAS signal is modeled separately in the PRA
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95

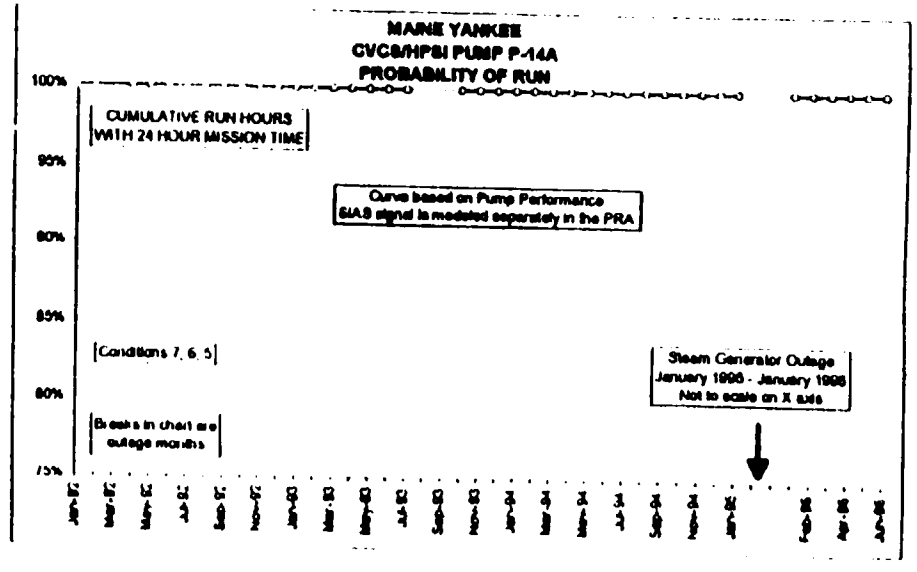

MAINE YANKEE
CVCS/HPSI PUMP P-14A
PROBABILITY OF RUN
100%
95%
90%
85%
80%
75%
CUMULATIVE RUN HOURS
WITH 24 HOUR MISSION TIME
Curve based on Pump Performance
SIAS signal is modeled separately in the PRA
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Feb-95
Apr-95
Jun-95

Figure 5

Maine Yankee Independent Safety Assessment Team

High Pressure Safety Injection Pump Train P-14B - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

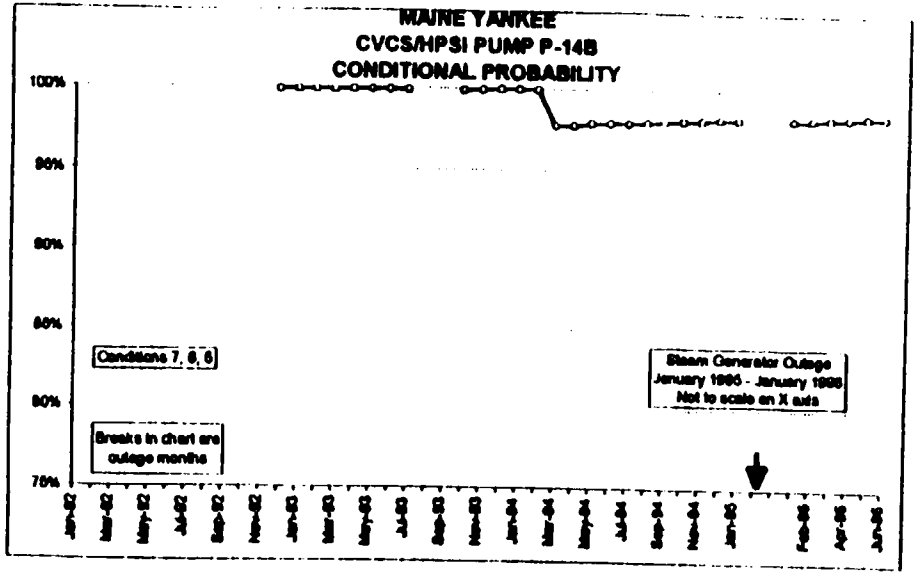
These curves represent the probability that the high pressure safety injection (HPSI) pump train P-14B will respond to a random demand, during power operation, for injection into the reactor vessel and will start and will inject into the reactor vessel for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

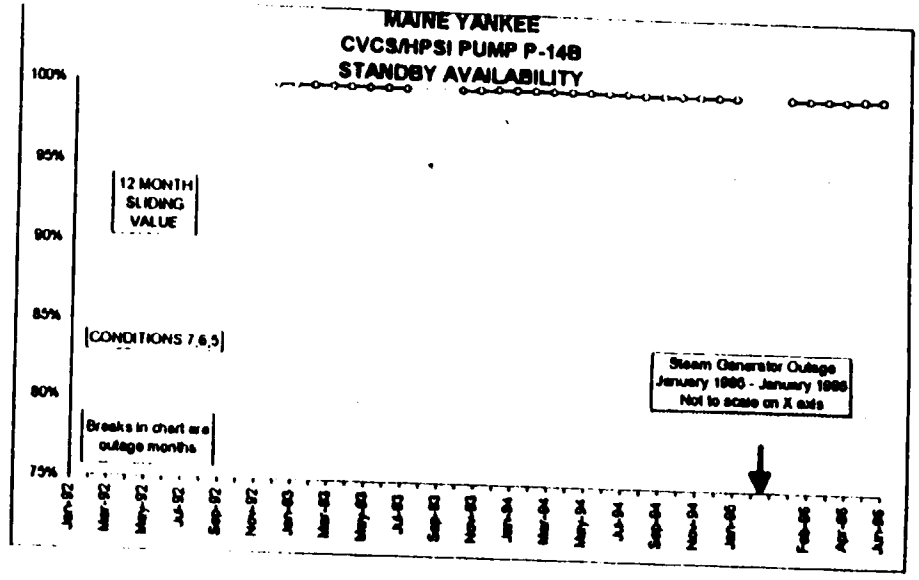
The conditional probability curve shows a very high value (over 99 percent) until March 1994. On March 23, 1994, P-14B failed to start because of control problems. There have been no failures to run of the pump train over the time period.

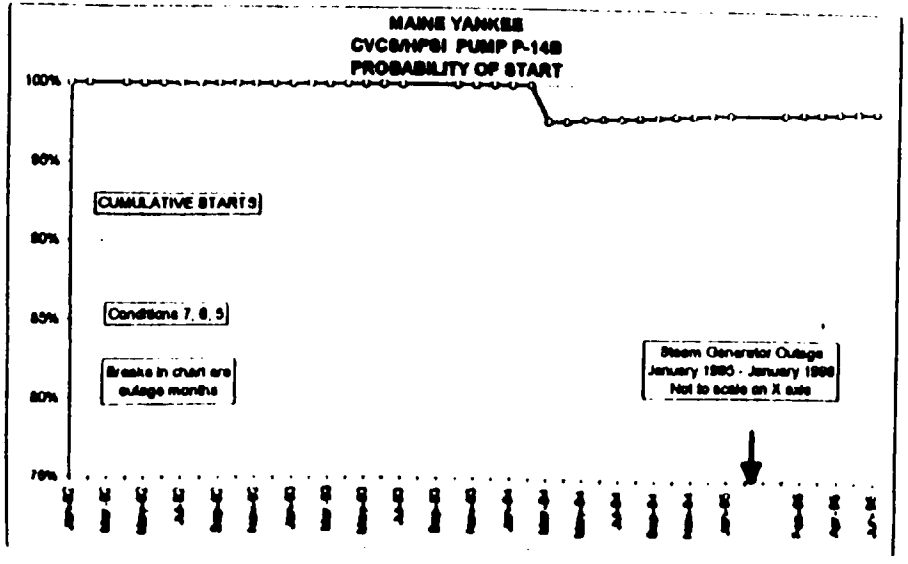
The value of the conditional probability as of June 30, 1996, was 98.5 percent. Thus it is expected that the HPSI pump train P-14B would complete its mission approximately 98 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	68
Successful Starts	68
Failures to Start	1
Total Run Hours	6,592
Run Failures	0
While aligned	
Planned Maintenance Hours	9.5
Unplanned Maintenance Hours	0.7


MAINE YANKEE
CVCS/HPSI PUMP P-14B
CONDITIONAL PROBABILITY
100%
95%
90%
85%
80%
75%
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
CVCS/HPSI PUMP P-14B
STANDBY AVAILABILITY
100%
95%
90%
85%
80%
75%
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
CVCS/HPSI PUMP P-14B
PROBABILITY OF START
100%
95%
90%
85%
80%
75%
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

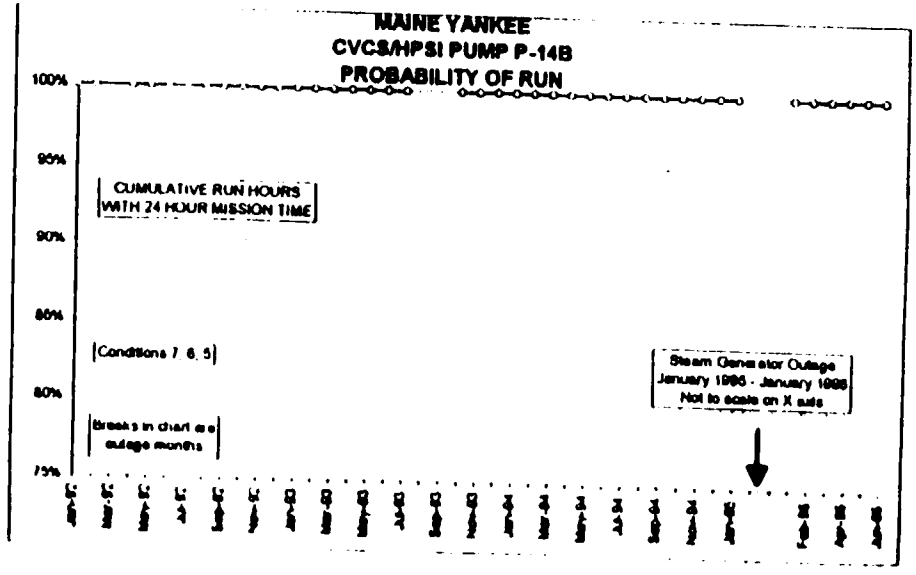

MAINE YANKEE
CVCS/HPSI PUMP P-14B
PROBABILITY OF RUN
100%
95%
90%
85%
80%
75%
CUMULATIVE RUN HOURS WITH 24 HOUR MISSION TIME
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

Figure 6

Maine Yankee Independent Safety Assessment Team

High Pressure Safety Injection Pump Train P-14S - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

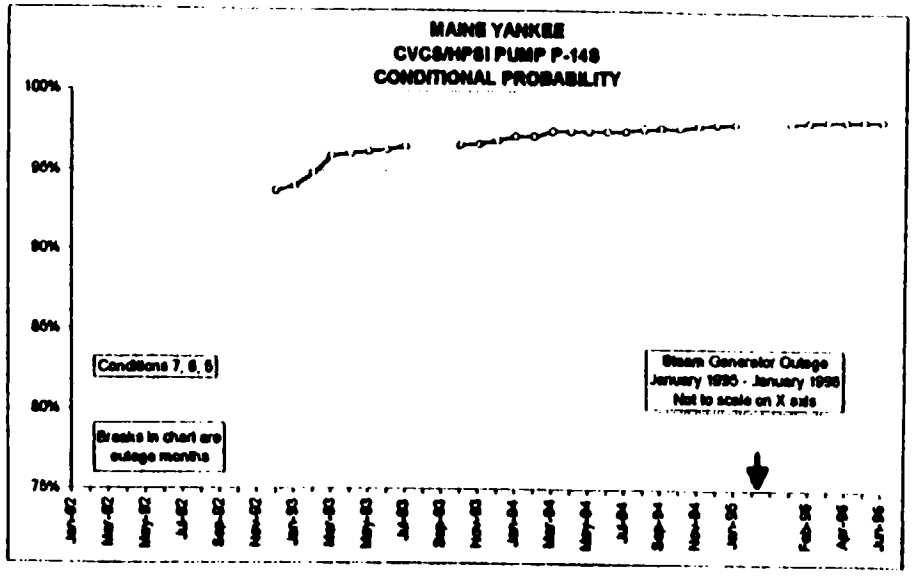
These curves represent the probability that the high pressure safety injection (HPSI) pump train P-14S will respond to a random demand, during power operation, for injection into the reactor vessel and will start and will inject into the reactor vessel for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

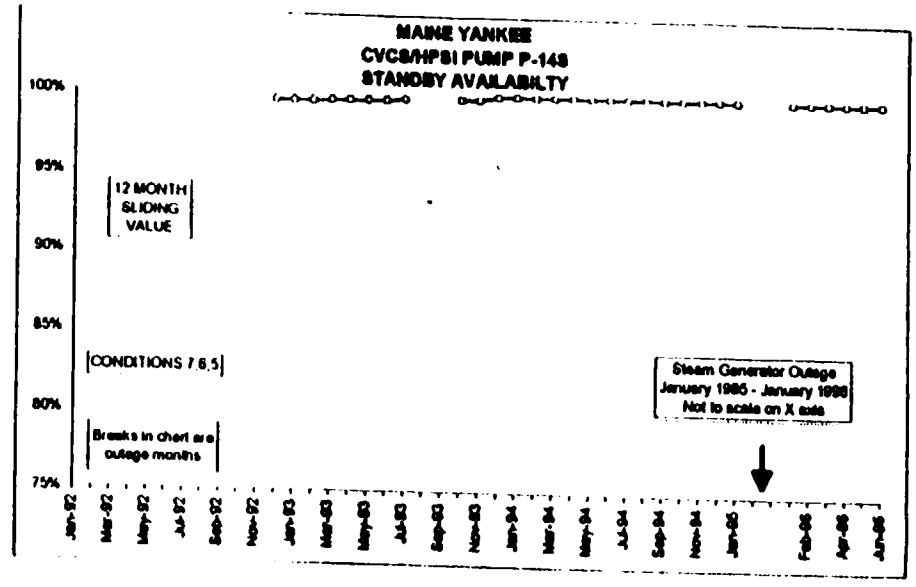
On August 5, 1992, there was a failure to start of P-14S. There were no other failures in this pump train over the time period. The Conditional Probability curve shows that the value was relatively low at the beginning of the period (93.7 percent) and has risen to 98.3 percent over the time period.

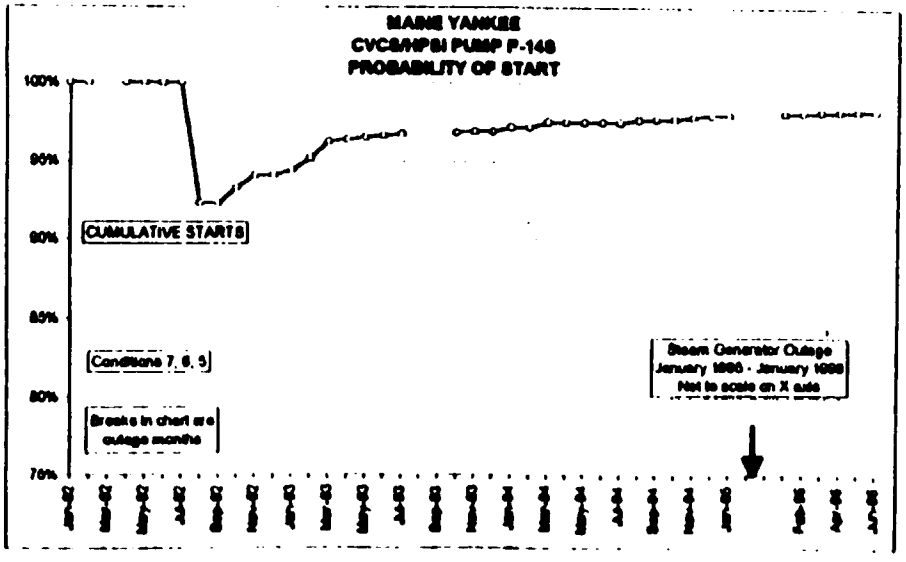
The value of the conditional probability as of June 30, 1996, was 98.3 percent. Thus it is expected that the HPSI pump train P-14S would complete its mission approximately 98 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	60
Successful Starts	59
Failures to Start	1
Total Run Hours	11,159
Run Failures	0
While aligned	
Planned Maintenance Hours	27.3
Unplanned Maintenance Hours	0.0


MAINE YANKEE
CVCS/HPSI PUMP P-148
CONDITIONAL PROBABILITY
100%
95%
90%
85%
80%
75%
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
CVCS/HPSI PUMP P-148
STANDBY AVAILABILTY
100%
95%
90%
85%
80%
75%
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis


MAINE YANKEE
CVCS/HPSI PUMP P-148
PROBABILITY OF START
100%
95%
90%
85%
80%
75%
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

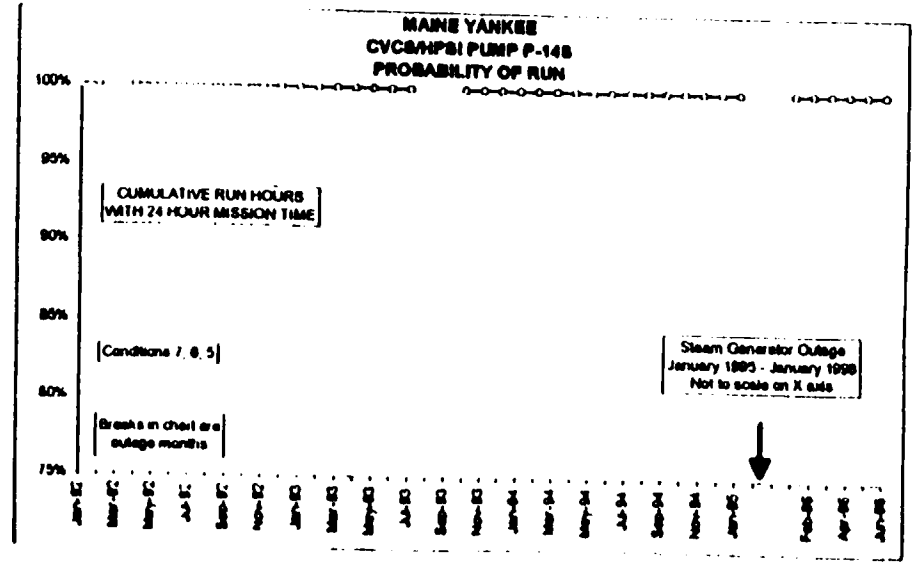

MAINE YANKEE
CVCS/HPSI PUMP P-148
PROBABILITY OF RUN
100%
95%
90%
85%
80%
75%
CUMULATIVE RUN HOURS WITH 24 HOUR MISSION TIME
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage
January 1995 - January 1996
Not to scale on X axis

Figure 7

Maine Yankee Independent Safety Assessment Team

Emergency Diesel Generator Train EDG-1A - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

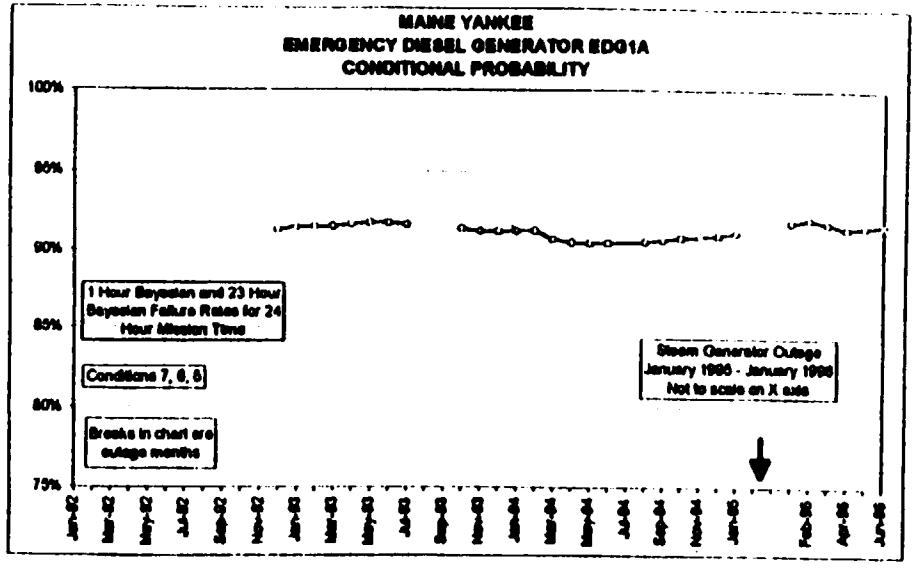
These curves represent the probability that the emergency diesel generator (EDG) train EDG-1A will respond to a random demand, during power operation, for ac electric power to its 4.16 kV bus and will start and power the bus for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

On April 23, 1996, there was a failure to run of EDG-1A. There were no other failures in this EDG train over the time period. The conditional probability curve shows that the value was relatively constant over the time period (90 to 92 percent).

The value of the conditional probability as of June 30, 1996, was 91.7 percent. Thus it is expected that the EDG train EDG-1A would complete its mission approximately 92 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	67
Successful Starts	67
Failures to Start	0
Total Run Hours	113
Run Failures	1
Planned Maintenance Hours	367.5
Unplanned Maintenance Hours	86.2


MAINE YANKEE
EMERGENCY DIESEL GENERATOR EDG1A
CONDITIONAL PROBABILITY
100%
95%
90%
85%
80%
75%
1 Hour Bayesian and 23 Hour Bayesian Failure Rates for 24 Hour Mission Time
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
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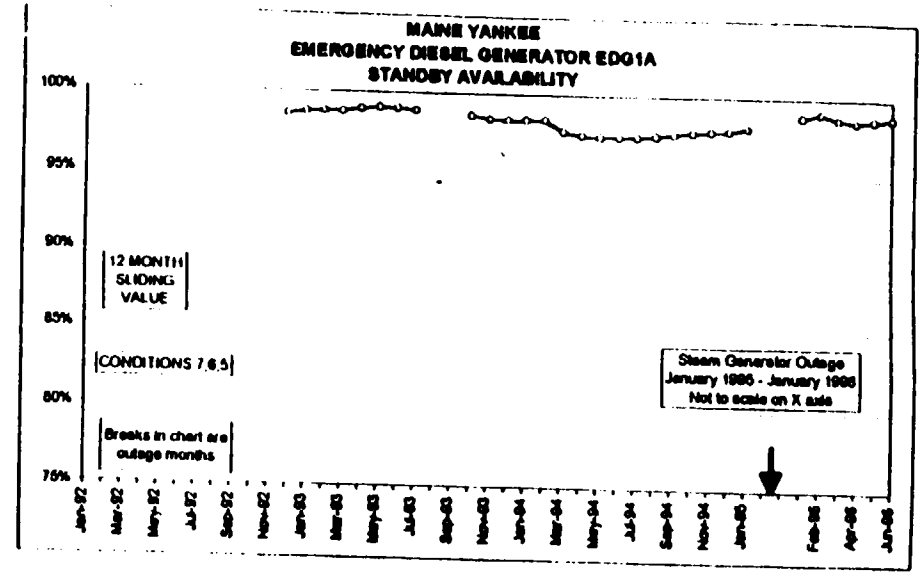
MAINE YANKEE
EMERGENCY DIESEL GENERATOR EDG1A
STANDBY AVAILABILITY
100%
95%
90%
85%
80%
75%
12 MONTH SLIDING VALUE
CONDITIONS 7,6,5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
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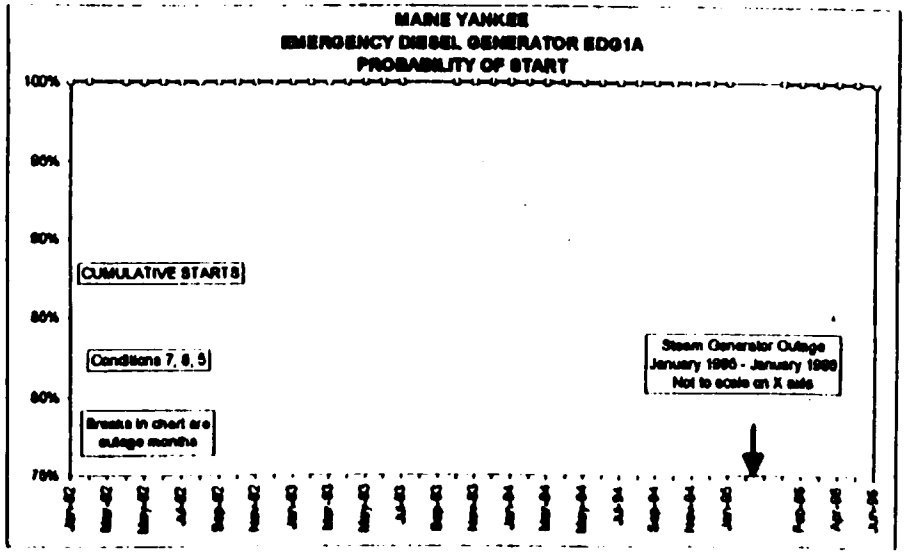
MAINE YANKEE
EMERGENCY DIESEL GENERATOR EDG1A
PROBABILITY OF START
100%
95%
90%
85%
80%
75%
CUMULATIVE STARTS
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
Jan-92
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Nov-92
Jan-93
Mar-93
May-93
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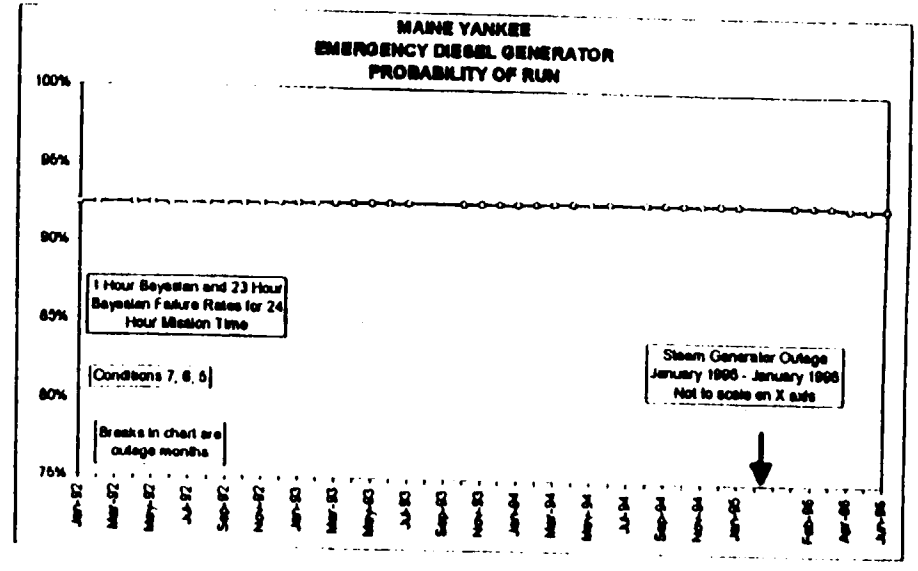
MAINE YANKEE
EMERGENCY DIESEL GENERATOR
PROBABILITY OF RUN
100%
95%
90%
85%
80%
75%
1 Hour Bayesian and 23 Hour Bayesian Failure Rates for 24 Hour Mission Time
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
Jan-92
Mar-92
May-92
Jul-92
Sep-92
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Jun-95

Figure 8

Maine Yankee Independent Safety Assessment Team

Emergency Diesel Generator Train EDG-1B - Conditional Probability
Operating Conditions 5, 6, 7 from January 1, 1992 to June 30, 1996

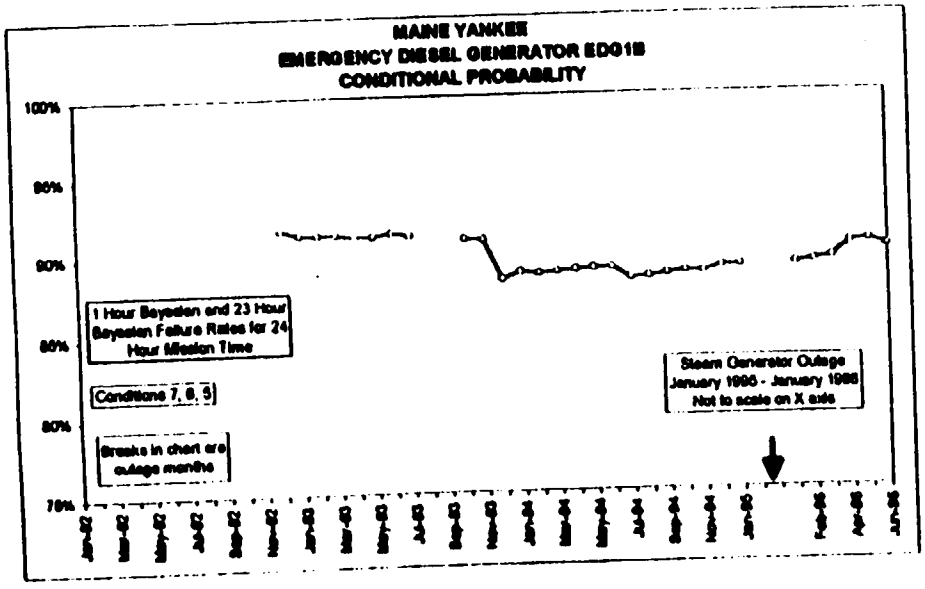
These curves represent the probability that the emergency diesel generator (EDG) train EDG-1B will respond to a random demand, during power operation, for ac electric power to its 4.16 kV bus and will start and power the bus for 24 hours. The conditional probability is calculated by determining the product of (1) the standby availability (ratio of time not in maintenance to the total time in operating conditions 5, 6 and 7), (2) the probability of start (cumulative successful starts/cumulative total starts), and (3) the probability of run (run for 24 hours given a successful start).

On December 17, 1993, there was both a failure to start of EDG-1B and a failure to run of EDG-1B. There were no other failures in this EDG train over the time period. The conditional probability curve shows that the value varied over the time period from 88 to 92 percent. The overall trend has been negative except for the last few months.

The value of the conditional probability as of June 30, 1996, was 90.1 percent. Thus it is expected that the EDG train EDG-1B would complete its mission approximately 90 out of 100 random demands.

For these curves, high values are better than low values.

Total Starts	80
Successful Starts	79
Failures to Start	1
Total Run Hours	111
Run Failures	1
Planned Maintenance Hours	396.5
Unplanned Maintenance Hours	132.5


MAINE YANKEE
EMERGENCY DIESEL GENERATOR EDG1B
CONDITIONAL PROBABILITY
100%
95%
90%
85%
80%
75%
1 Hour Bayesian and 23 Hour Bayesian Failure Rates for 24 Hour Mission Time
Conditions 7, 6, 5
Breaks in chart are outage months
Steam Generator Outage January 1995 - January 1996 Not to scale on X axis
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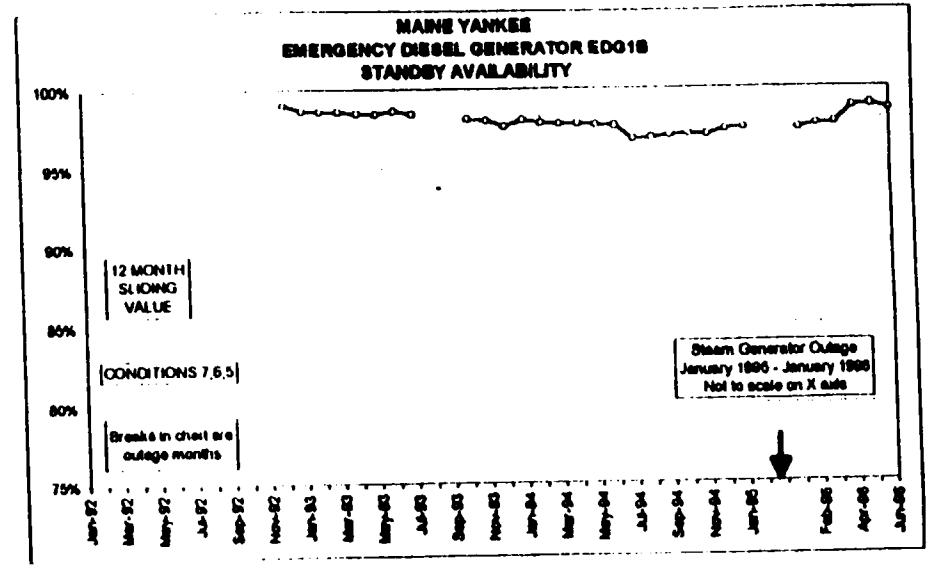
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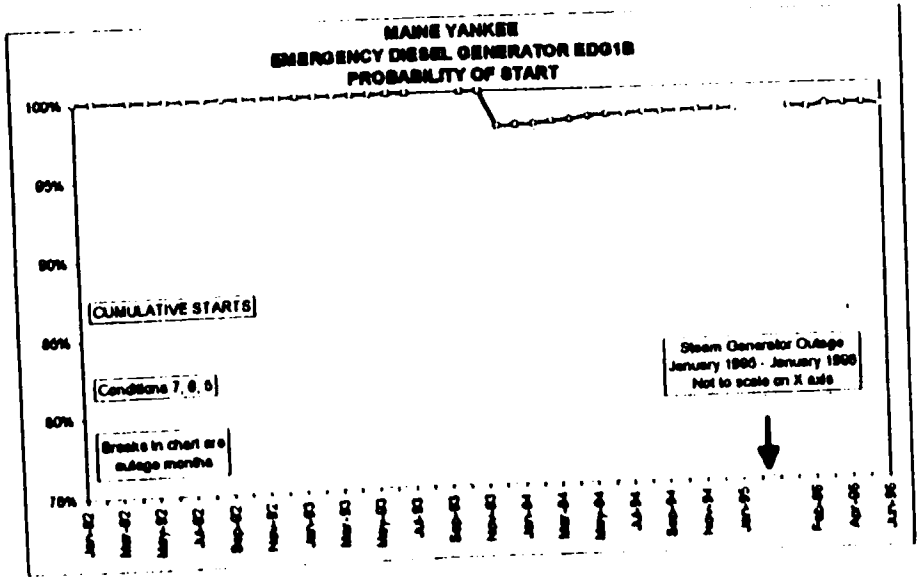
MAINE YANKEE
EMERGENCY DIESEL GENERATOR EDG1B
PROBABILITY OF START
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90%
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CUMULATIVE STARTS
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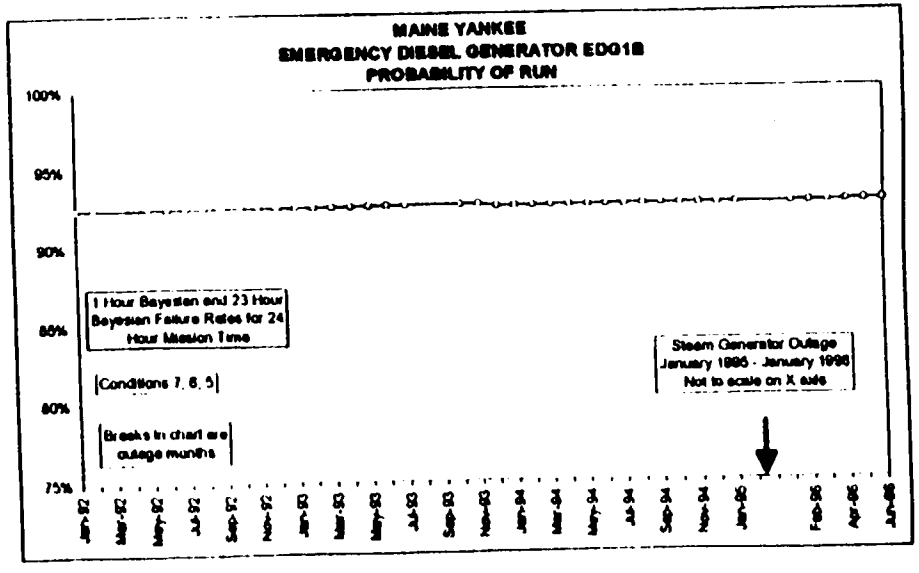
MAINE YANKEE
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Maine Yankee
Independent Safety Assessment Team

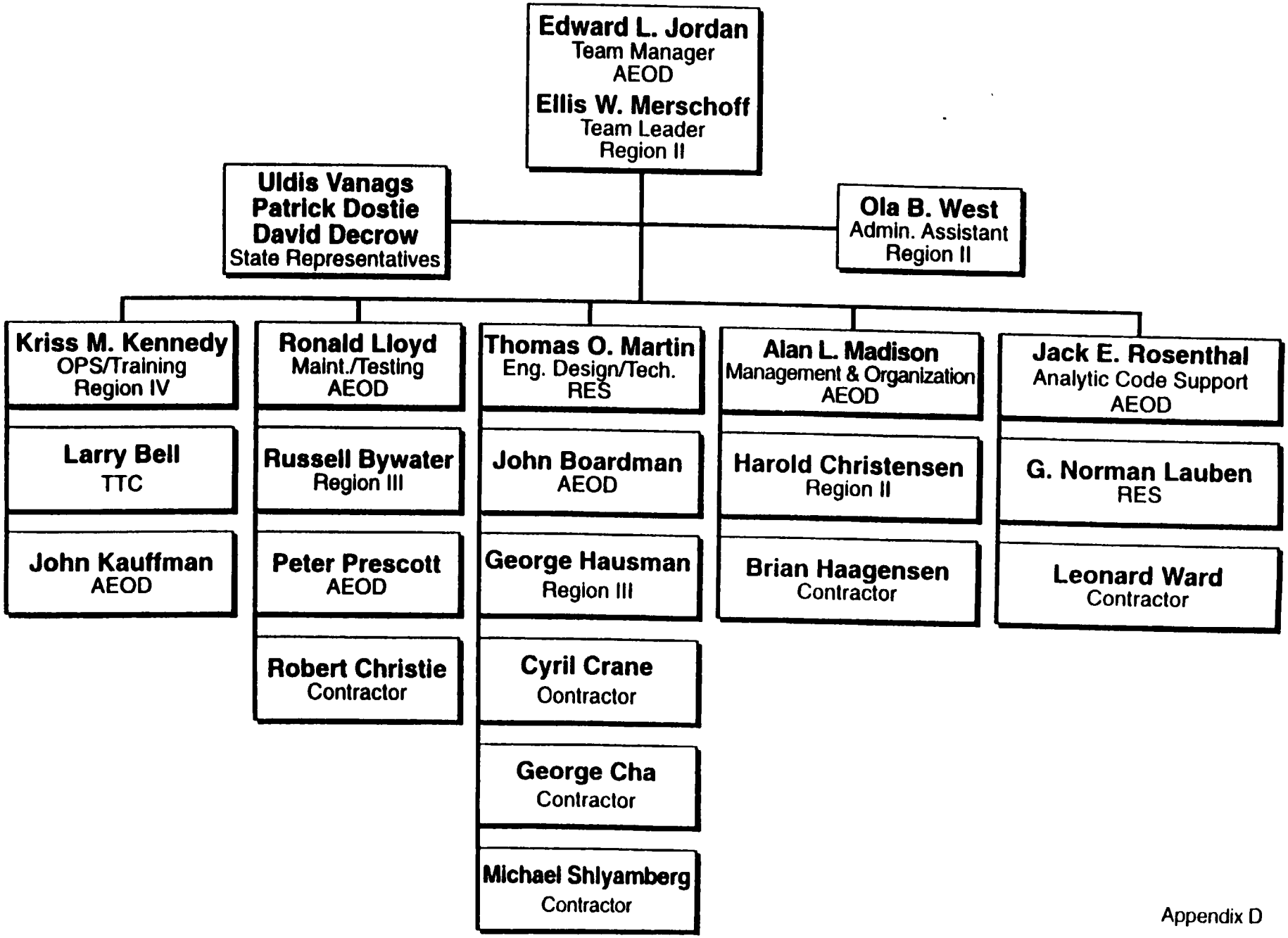

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Exhibit C

CULTURAL ASSESSMENT TEAM REPORT

ON

FACTORS AFFECTING THE REPORTING

OF

ISSUES AND CONCERNS AT MAINE YANKEE

Robert E. Bradford
Jacquel-Anne Choquinard
Richard H. Fallon, Jr.
Jeffrey D.E. Jeffries

May 14, 1996

Exhibit C

I. INTRODUCTION

In March of 1995, senior management at Maine Yankee assembled a Cultural Assessment Team ("CAT") to determine "whether, or to what extent, Maine Yankee may have a culture that discourages employees from raising concerns, particularly nuclear safety concerns." This is the report of that Team's effort.

An introductory section briefly discusses relevant background, then outlines the Team's charter and describes its methodology. Substantive sections present the Team's findings concerning the Maine Yankee culture and address the apparent causal factors. Within the cultural findings section, the report briefly summarizes the cultural elements within the Radiation Protection organization and the Instrumentation & Controls Section of the Maintenance Department. The report also includes recommendations for improving the culture at Maine Yankee and for correcting some of the more significant causal factors.

Throughout this report, the focus is on the general culture at Maine Yankee and possible strategies for improving that culture. It was not part of the CAT charter to investigate particular events, and no attempt has been made to do so. Nor, for the most part, has there been an attempt to determine whether the perceptions, beliefs, and attitudes that prevail among the workforce mirror factual reality. Widely shared perceptions and beliefs define a culture with a reality of its own. The cultural environment, once established, profoundly influences behavior, motivation, and willingness to express safety and other concerns within any organization, and Maine Yankee is no exception.

II. BACKGROUND and CHARTER

As reflected in evaluations conducted over the years by both organizational management and outside auditors, Maine Yankee -- at least until the recent, nearly year-long outage to repair cracks in steam generator (S/G) tubes -- has had an excellent operating history. In addition, according to

information derived from a variety of sources, its workforce has traditionally exhibited high morale. Throughout Maine Yankee's some twenty-three years of operation, there were very few recorded cases associated with employee issues and/or concerns raised with management. Recently, however, there have been some indications of deviations from past trends and patterns. It was senior management's recognition of these anomalies which led to the creation of the Cultural Assessment Team.

A. Sources of Concern

In January and February of 1996, top-level management at Maine Yankee received a number of concerns via processes outside the chain-of-command, along with indications that at least some employees within the organization who wished to raise issues were either fearful of, or perhaps subject to, harassment and intimidation. Within these two months alone, eight separate items were registered with the organization's Worker Concerns Program ("WCP"),[1] in comparison with four such items during all of 1995, and only one in 1994. Another illustration of this situation was an individual's unwillingness to complete the annual Code of Conduct survey administered by the General Counsel and Audit Manager. Indications were also received via the Employee Assistance Program (EAP) that some employees were fearful of raising concerns, including some possibly related to safety.

The above indications of increased worker concerns, including reported fears about possible harassment or intimidation, came at a time of significant change within the electric utility industry, in general, and the Maine Yankee organization, in particular. During a regularly scheduled refueling and maintenance outage that began in February 1995, widespread cracking of tubes was detected

[1] Some of these matters were raised initially within the chain-of-command, while others were presented directly to the component of the WCP located in the Quality Programs Department. Only one of the eight items appears to have had direct safety significance, and it involved industrial rather than nuclear safety.

in all three of the unit's steam generators ("S/Gs"). Initially, it was uncertain whether the Board of Directors would approve the expenditures required to effect repairs and thus whether the plant would ever resume power production. Ultimately, the company determined to address the problem by welding reinforcing "sleeves" onto substantially all of the plant's 17,000 S/G tubes, and the Nuclear Regulatory Commission ("NRC") approved this response. The re-sleeving process placed the plant in a forced outage condition until January 1996; this was a significant departure from the traditional operating pattern. During and subsequent to the year long outage, selected financial cutbacks, including a revised compensation plan that eliminated paid overtime for all exempt employees, were imposed.

Another departure from past, successful patterns was a recent allegation. In December 1995, the Union of Concerned Scientists released an anonymous letter alleging that Maine Yankee officials had colluded in providing fraudulent information to the NRC in 1989. The letter, apparently written by a former employee of Yankee Atomic Electric Company (Maine Yankee's primary engineering firm), claimed that the version of a computer code (RELAP5YA) used to justify an increase in the reactor's thermal power rating from 2,630 to 2,700 megawatts was, in fact, inadequate. The letter claimed Maine Yankee officials knew the code was inadequate when they submitted the attendant license change to the NRC. Maine Yankee has hired a Washington law firm, Morgan, Lewis & Bockius, to conduct an independent inquiry into this allegation.

B. The Cultural Assessment Team (CAT) Charter

In this context, Maine Yankee's President and CEO, with the concurrence of senior management, decided to assemble a team of individuals with diverse backgrounds -- including experience in human resources, psychology, law, and nuclear engineering and safety -- to examine the environment at Maine Yankee for the reporting of employee issues and concerns, especially but

not exclusively those relating to safety. The team members are Dr. Robert E. Bradford, Managing Director, Dallas Office, Roher, Hibler & Replogle, Inc.; Jacquel-Anne Chouinard, Human Resources Consultant; Richard H. Fallon, Jr., Professor of Law, Harvard Law School (team coordinator); and Dr. Jeffrey D.E. Jeffries, President, Paradigm Consulting Services, Inc. All are entirely independent of Maine Yankee.

The charter gives the team three principal objectives: (1) to determine if there is a culture at Maine Yankee that fosters openness and communication by workers or one that discourages such communication; (2) to evaluate the effect of the organizational culture on utilization of the Maine Yankee Worker Concerns Program and employees' perceptions of the Program's effectiveness; and (3) to make recommendations for improving any identified deficiencies. The charter also charges the CAT to determine the apparent causal factors, if it is found that the atmosphere is one that does not foster open communications. The CAT was requested to "focus, in particular, on the environment within the Radiation Protection Department," since a number of the recent concerns appeared to be associated with that part of the organization. For these objectives to be fulfilled, the charter gives the Team a relatively broad latitude. Individual and group interviews are considered to be the primary means of gathering the required information, but other research was authorized as the CAT deemed necessary, "including review and analysis of documents and other industry concern programs."

Under its charter, the Team is charged with reporting its findings directly to the President/CEO of Maine Yankee. If any potential safety significant issues arose during the conduct of this effort, the CAT was to promptly inform the Acting Manager of Quality Programs. A copy of the charter is included as Attachment A.

III. METHODOLOGY

A. Data Gathering

To assess the culture at Maine Yankee, the CAT requested and examined relevant documents assembled by the organization. Collectively, these documents provided insight into the prevailing culture and gave an indication of how Maine Yankee has handled significant issues in the past. The Team relied most heavily, however, on interviews with employees.

B. Interviewee Selection

While it was not the intent of the CAT effort to provide a statistically supported evaluation, it was important to compile information from a broad cross-section of the organization. To this end, the Team reviewed the organizational charts and made an initial decision to interview at least 10% of the organization, including individuals from each department and each major organizational level -- officer, manager, supervisor, and worker. The actual selection process for interviewees was quasi-random, although a few employees were specifically identified to be interviewed because they occupied positions of special relevance to the charter objectives.[2] It was also determined that any employee who specifically requested to talk with the Team would be included in the data gathering. Even prior to the inclusion of employees requesting interviews, this method of selection yielded a list of about 80 employees to be interviewed -- roughly 15% of the Maine Yankee workforce. Both individual and group interviews were scheduled. In order to accommodate scheduling problems, however, Maine Yankee liaison personnel were given discretion to make substitutions involving both individual and group interviews in consultation with the Team coordinator. The Team ultimately interviewed 96 Maine Yankee employees, including 80 employees invited by the CAT and 16 volunteers. Of the invited interviewees, 34 participated in group interviews, while 62 individual interviews were conducted. All employees who asked to talk with the CAT were

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[2] In each case alternate invitees were identified in case difficulties arose in scheduling interviews.

interviewed individually.

C. Approach

Background information about the CAT was provided to the Maine Yankee workforce primarily through a memorandum from the President/CEO of the Company. Throughout the notification process, management and the CAT made it known that anyone who wished to speak with the Team would be welcome to do so. Employees were also instructed that all interviews were voluntary; anyone could decline to be interviewed, and interviewees could leave the interviews at any time.

Team members began interviews by advising the interviewees of the nature of the CAT mission, and informing them that nothing they might say would be attributed to them in the Team's final report. Open-ended questions were posed to each interviewee, with the aim of eliciting the employees' perspectives on Maine Yankee's mechanisms for reporting worker issues and concerns, the effectiveness of those mechanisms, cultural factors which could directly affect an employee's willingness to express concerns, and more general cultural factors, including perceptions of management and Maine Yankee's future which might have an indirect effect on reporting. An outline of initial sample questions is included as Attachment B, but due to the desire to provide a wide latitude for discussion, many interviews did not adhere to this form.[3]

For the most part, the Team members believe that interviewees were candid and forthcoming about their perceptions, concerns, and recommendations for improvement. A few interviewees appeared reticent; a smaller number were noticeably defensive. But the vast majority appeared relaxed and projected a sincere desire to help the Team achieve its mission. In light of the responses to the interviews, the CAT believes it has been able to satisfy the objectives stated in the charter.

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[3] The individual interviews frequently made it possible to elicit personal viewpoints in significant depth. The group interviews often yielded perspectives that can emerge only in an interactive setting.

It should be emphasized, however, that the charter called for the provision of a general cultural assessment, reflecting the Team's diverse backgrounds and areas of expertise, rather than a quantified sample of expressed opinions. A statistically valid poll was not conducted. In this report, empirical data is not provided, nor are conclusions advanced which are either capable of, or supported by, statistical proof. Instead, diverse questions were asked, and lines of inquiry that seemed most illuminating in particular interviews were followed. The Team gathered information, then collated, synthesized and interpreted it to characterize the culture at Maine Yankee -- in particular, the effect of that culture on employee willingness to report issues and concerns to management.

IV. FINDINGS CONCERNING THE CULTURAL ENVIRONMENT

The principal charge to the CAT was to assess the culture at Maine Yankee and its effect on employees' willingness to raise safety issues and other concerns. In response to this charter objective, the Team found that the culture generally encourages the raising of issues perceived as having significant implications for nuclear safety, but it does not foster open communication of other concerns, including some with potential safety significance.

A. Safety Concerns Perceived as Significant

Nearly without exception, employees interviewed by the CAT agreed there is a general willingness among Maine Yankee employees to raise issues and concerns which are perceived as having significant safety implications.[4] Management encourages such reporting, and ample reporting systems appear to exist, both through the chain-of-command and the Worker Concerns Program. Moreover, there is general agreement among employees at all levels that the organization responds well to such issues, i.e., they are resolved with the appropriate attention and speed.

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[4] The safety significance of an issue or concern seems to be based on individual backgrounds and experience bases; to the CAT, this implied a lack of consistency in the reporting thresholds through the organization.

B. Other Issues

With respect to issues perceived as not safety significant, the CAT found a substantial gap between expressed management expectations and actual conditions. Management has indicated that all issues and concerns should be raised and addressed in an open and forthright manner, but this was found frequently not to be the case for those items deemed non-safety significant, especially at the plant. With respect to personnel issues in particular, many employees and managers expressed a lack of confidence in the Human Resources Section and, accordingly, a reluctance to raise personnel concerns.

C. Findings of Fact and Extent of Condition

The charter contemplates that the CAT will report findings of fact and an assessment of the extent of conditions regarding the reporting culture at Maine Yankee. In response to this charge, the Team made the following basic findings of cultural fact:

1. Lack of Follow-through

A widespread perception exists among the workforce that Maine Yankee generally achieves little or no organizational follow-through on concerns not viewed as safety significant. Issues raised with supervisors usually receive acknowledgment, but marginal long term response. Management above the supervisory level is seen as substantially indifferent to concerns not perceived as possessing relatively immediate safety significance. The volume of work coupled with a reactive management style leads to a continuing cycle of issues "falling off the table" without receiving the necessary redress.

2. High Threshold

Many if not most employees believe that a relatively high threshold for reporting is appropriate, given the plant situation. The current economic and political environment is considered

precarious, and Maine Yankee's survival is seen to be based on a formula of low cost and high production. There is an associated fear among many employees that highlighting any negative issue could endanger the plant's continued operation. No one wants to be responsible for a premature plant shutdown and decommissioning.

3. The Forces of Change

At Maine Yankee, the Team found an organization struggling with forces requiring unprecedented change. These include evolving performance standards as well as deregulation within the electric utility industry. Senior managers have recognized the potential impact of these forces for some time, but their message has not always been clearly articulated to the rest of the company. Moreover, the response has been uneven by the organization at large, and has included some overt resistance.

4. Mixed Messages

Another common belief within the workforce is that management is tolerant of some corner-cutting if it occurs in areas perceived as "low risk," even though their stated position requires that safety should be placed first and procedures strictly followed. More specifically, workloads are often seen to be unrealistic; there is a sense that assigned tasks cannot possibly be completed on time if all of the quality standards are met and the procedural requirements are observed. Many workers assume that management must be aware of this situation, and must therefore condone employees "working around" procedures to complete their tasks on schedule. Building on this impression, many workers further assume that management does not want to hear about issues that might slow work or otherwise hinder productivity.

5. Deteriorating Organizational Relationships

Many elements within the Maine Yankee organization are seen as self-protective.

There is a sense that the levels of cooperation and teamwork have been on the decline for some time, and are currently at an all time low. In addition, a significant distrust has developed between the workforce and management, as many employees grow increasingly concerned about the organization's long-term future.

D. Cultural Environment in Selected Units

1. Radiation Protection

The CAT found the cultural environment in the Radiation Protection ("RP") organization to be similar to that exhibited elsewhere in the company, though perhaps somewhat more severe in terms of degree. Significant tension appears to exist between Radiation Protection and some other units, especially the Maintenance Department. The principal issue involves competing pressures for adherence to procedures and for the timely completion of work. To some extent, the tension between RP and other departments appears to be the result of a somewhat skewed division of responsibilities within Maine Yankee. Radiation workers, in general, have apparently failed to accept the primary responsibility and accountability for their own radiation exposure, and the RP organization, which has effectively assumed this role, is easily viewed as an obstruction to low cost production. Nonetheless, it seems clear to the Team that Radiation Protection has some distinctive, internal problems.

From both inside and outside, RP management is widely perceived as somewhat arbitrary and as too reactive to specific incidents and deficiencies. In addition, they are seen as disengaged, with little understanding of, or appreciation for, the practical problems encountered by front-line workers. As a result, management involvement is frequently viewed as counterproductive. Frustration and confusion levels are high within the RP organization, with supervisors seen as generally ineffectual. Numerous employees indicated that they have stopped raising concerns unless

they exceed a high threshold of significance.

In spite of the aforementioned difficulties, there is widespread belief that the RP organization adequately meets its safety responsibilities due to the personal commitment and good judgment of front-line personnel. Nonetheless, there is a disturbing clash between the perceptions of many technicians, on one hand, and at least some mid-level managers on the other. Some in management believe that both reporting and performance standards are too low; they see their direct interventions as necessary to bring the organization up to reasonable industry standards. By contrast, many employees believe that management is out-of-touch, reactive rather than constructive, and ineffective. Based on the information available, it appears there is some truth in both of these seemingly conflicting perceptions.

2. Instrumentation and Controls

Based on information derived from CAT interviews, the culture prevailing in the Instrumentation and Controls ("I&C") Section does not differ sufficiently from that in the rest of the organization to warrant a separate discussion. There are some individuals within I&C who have special anxieties or frustrations about reporting concerns, but the information gathered by the Team failed to support any additional relevant insights or conclusions.[5]

E. The Worker Concerns Program

Beyond providing a general charge to assess the cultural environment bearing on the raising of employees' concerns, the CAT's charter specifically mandated an evaluation of "the effect of the culture on utilization of the Maine Yankee Worker Concerns Program, and employees' perceptions of the Program's effectiveness." As the CAT's interviews made clear, however, reference to the

[5] The CAT was not charged with responsibility for investigating particular events or allegations. Investigations of this kind call for a different method of inquiry, and different kinds of protections for both those accused of wrongdoing and those providing relevant information, than the type of general cultural assessment that was the CAT's mission.

WCP is ambiguous. As used in the chartering documents, the term encompasses both expressions of concern raised within the chain-of-command and those channeled directly or indirectly to a part of the program administered by the Quality Programs Department. In this latter program element, employees are provided the opportunity to raise safety and other concerns outside the chain-of-command, and may do so anonymously if they wish. During interviews, however, virtually all Maine Yankee personnel understood the WCP to be distinct from the chain-of-command. Following this broad-based understanding, the CAT has treated the Worker Concerns Program as encompassing only those matters which are referred outside the normal line organization to the Quality Programs Department and will refer separately to concerns raised within the chain-of-command.

1. Awareness of Existing Programs for Raising Concerns

When asked about existing mechanisms for raising safety and other concerns, nearly all employees interviewed responded by referring to the chain-of-command. For almost all, this was the primary reporting mechanism. By many, it was viewed as exclusive. Although some employees cited the WCP, awareness of its existence appears not to have permeated very deeply within the general ranks of the Maine Yankee organization. Among those employees who either referred specifically to the WCP or were asked about it, a significant number described it as designed only to deal with concerns satisfying a relatively high threshold of seriousness.

In addition to the chain-of-command and the WCP, the Team encountered scattered references to a number of other reporting processes, including a "Safety Issues Concern Program" and an "Employees' Suggestion Program." According to individuals involved with the Learning

Process ReEngineering Team,[6] Maine Yankee has roughly sixty different processes for identifying or tracking various kinds of issues, including equipment and performance deficiencies. Whether despite or because of the large number of available reporting systems, the vast majority of employees appeared uncertain about how or whether they ought to report issues and/or concerns outside the chain-of-command if the issues or concerns do not reach a relatively high level of seriousness.

Supervisors, as the primary recipients of expressions of concern raised within the line organization, appear not to differ much from the other workers in their awareness of existing programs for reporting issues and concerns. They generally understand that they have a responsibility to listen and respond to issues brought to them, but few appear to accept much, if any, responsibility to fill out forms or otherwise make a record of the concerns raised. Also within the supervisor ranks, there is a general awareness of the WCP, but an apparent reluctance to use it.

2. Perceptions of Existing Programs' Effectiveness

As noted in earlier sections of this report, there is a strong, prevailing sense that the chain-of-command responds effectively to expressed safety concerns that are perceived as significant, but that the line organization deals poorly with other concerns that are perceived as less serious, especially "people issues."

Among those aware of its existence, the Worker Concerns Program gets mixed reviews. Several interviewees went out of their way to laud the attributes of the WCP administrator. At the same time, several others stated that they would not trust the program to maintain the anonymity of individuals expressing concerns -- either because conversations often appear not to

[6] The Learning Process ReEngineering (LPRE) Team was formed by Maine Yankee to address the multiple reporting systems at the site. The primary objective of the LPRE charter is to integrate the multiple elements of the corrective action program into an effective vehicle for identifying and reporting deviations and deficiencies.

be properly guarded, or because the ultimate resolution of any concern would inevitably need to occur at some level within the chain-of-command, where anonymity is viewed as impossible. Several employees expressed anxiety based on their belief that retaliation was a distinct possibility if some types of issues were raised and those raising the issues were subsequently identified; as a result, some concerns have gone unreported. In addition, as noted above, there seems to be a widespread misunderstanding that the WCP may be used only for issues of considerable safety impact or seriousness. As a result, the program is widely perceived as ineffective for dealing with other issues.

V. APPARENT CAUSAL FACTORS

The charter provides that "[i]f a culture or atmosphere which does not foster open communications is found, the Team shall determine the apparent causes of the conditions." Because the strands of a culture are inevitably and complexly interwoven, the causal factors that give rise to the current condition in the Maine Yankee organization are multiple and mutually reinforcing. Although several classifications would be possible, the CAT has identified three principal categories of underlying causes for the conditions described above: (i) historically established priorities, (ii) ineffective change management, and (iii) deteriorating organizational relationships.

A. Historically Established Priorities

For many years Maine Yankee has operated in a somewhat hostile environment. Negative criticism has been received from the media, the public, and various interest groups. To function successfully in this environment, the organization appears to have established a set of priorities that became the basis of operations over a number of years. Today, those priorities are sufficiently entrenched in the Maine Yankee culture that they are seen as exerting an influence that is at least

partly independent of any conscious articulated policy of current management.[7]

The first priority is nuclear safety. Virtually without exception, employees say that they would never do anything to endanger public or environmental safety. But safety does not stand alone on the priority list. A second priority is sensitivity to cost. With inexpensive power apparently available nearby, Maine Yankee employees have traditionally accepted that continued survival depended on very low-cost production. Over the years, interviewees reported, money was spent only on areas that required it -- primarily on items dealing with safety and regulatory issues. Rarely were expenditures made on non-essential items, including preventive measures. Perhaps the most crucial point, however, is that the low-cost emphasis appears to have been overwhelmingly embraced by the workforce. Interviewees told the CAT that plant personnel learned over the years to avoid many potential expenditures by making do with what was available, and often, temporary measures were applied. Within the culture, it came to be widely accepted that issues should not be raised with management until all of the readily available remedies were exhausted. Based on the information provided by CAT interviews, it appears that some short cuts and selective non-compliance with procedures came to be viewed as appropriate means to keep costs low. While the organization takes pride in achieving low costs, lately the feeling has emerged that the material condition of the plant has deteriorated to the point where substantive improvements must be made. This perceived need to improve the plant's material condition happens to coincide with ever-mounting pressures to further reduce costs as the company prepares for a more competitive marketplace.

A third, closely related priority is high productivity. To survive, the plant must continue to

[7] The analysis in this section pertains most directly to employees in the plant itself. Comparable understandings of the organization's situation and priorities appear to be prevelent throughout the workforce, though there may be somewhat greater openness to change among administrative and clerical employees in Brunswick.

run, and most workers have considered lost productivity as a significant failure. As with low-cost operations, the high productivity value appears to be widely internalized. Among the workforce, the prevailing ethic places a high premium on reaching goals on time. There can be considerable resentment toward people, processes, procedures and decisions that hold up work or otherwise thwart efforts to meet objectives successfully. Moreover, there appears to be a strong disposition not to make trouble when matters could be handled at low levels. To put the point in a slightly different framework, the plant's "success profile" may have encouraged an attitude of "if they don't ask, we won't tell" in dealing with what are perceived as minor obstacles to successful performance. Within the culture, no entrenched ethic appears to discourage workers from taking matters to their supervisors, but long prevailing attitudes have apparently tended to discourage employees from going to management with issues not perceived as possessing significant safety implications.

This set of entrenched cultural attitudes, which is hardly conducive to the forthright raising of employee issues and concerns, appears to have been reinforced in some workers' minds by the series of events surrounding the 1995 outage. A clear message for many employees, especially those working in the plant, was that further major problems or events requiring significant expenditures could lead to a premature, permanent shutdown.

Staffing at Maine Yankee has historically been lean; many believe it is too lean. Reacting to pressures from a variety of sources, many workers -- especially technicians and supervisors -- think it is perhaps more important than ever to get the work done swiftly, without holdups or visible difficulties. A number of employees believe that at least a portion of management must be consciously or subconsciously looking the other way while some corner-cutting takes place.[8] Significantly, however, employee attitudes entrenched in the historically established culture are

[8] Again it should be noted that where corner-cutting is cited, individuals tend to be adamant about the fact that this practice only occurs in situations where there is no perceived safety significance.

resistant to the efforts of management within at least some parts of the organization to lower thresholds for the raising of issues and concerns. In the course of the CAT interviews, numerous employees suggested that management efforts to improve the safety culture simply illustrated that management was out-of-touch and failed to understand the sensible limits on what could be demanded of workers subjected to the competing pressures of high quality standards and rigid time constraints.

B. Ineffective Change Management

As reflected in both words and actions, top management at Maine Yankee appears to have developed an awareness that major changes are necessary to bring the organization into conformance with current industry standards and position the company for the competitive marketplace. These changes include the manner in which the organization deals with the identification and reporting of issues and concerns. But reform efforts, which are viewed as cutting against the grain of an entrenched culture, have not been managed effectively to date. Top and mid-level management are perceived as sending mixed messages with respect to the raising of issues and concerns. Moreover, many of management's attempts at improving performance through more stringent adherence to procedural requirements are widely seen as dysfunctional. When management responses to identified problems are regarded as out-of-touch or counterproductive, employees become far less willing to raise issues forthrightly.

1. The Changing Industry Environment

In interviews with the CAT, Maine Yankee managers communicated a recurring message about the need for change within the organization. For years, Maine Yankee was a somewhat insular, albeit highly successful, organization. But insularity -- and, in particular, maintenance of the entrenched cultural patterns discussed above -- is not a viable template for the

future. In the changing economic environment, which includes the impending deregulation of the electric utility industry, the organization must find ways to be even more cost-effective and efficient. High standards of quality and an open atmosphere to raise and resolve issues should also be embraced. For Maine Yankee, the changes require, to some extent, an overhaul in the way business is conducted; it will not suffice merely to use the same methods and techniques to become incrementally better. While management may understand the concepts of what is needed to be successful, there is a significant disparity between their views and the corresponding perceptions of many lower-level employees.

To describe the situation concisely, management has not been successful in providing leadership which convinces the workforce that change is necessary, nor has it succeeded in communicating a vision of the way Maine Yankee must operate to be successful in the future. Top management has not provided a vision around which the workforce can rally; it has not aligned the organization in a way that implements and reinforces new ways of doing business. Finally, management has not been able to inspire a sense of shared mission or develop support for change throughout the organization.

2. Perception of Mixed Messages

Although acknowledging that management consistently describes safety as the foremost organizational priority and repeatedly voices its openness to the forthright expression of worker concerns, many employees believe that the words belie the underlying reality. Three themes surfaced repeatedly in CAT interviews.

First, despite declarations to the contrary, management appears to tolerate some corner-cutting. Employees base this conclusion on what many take to be unrealistically high performance expectations coupled with tight schedules and a lean staff. Repeated comments to the

effect that it must be obvious to management that corners have to be cut in order to complete the volume of work assigned within the required time frame were heard during the CAT interviews.

Second, as noted above, when issues and concerns perceived not to be safety significant are raised, there is little, if any, follow through. Employees therefore draw the inference that management, despite what it says, is not really interested unless the impact is very high.

Third, management is increasingly invisible to the workforce. Top-level managers are seldom seen at the plant, and mid-level managers are viewed as being preoccupied with a managerial agenda that keeps them in frequent meetings with each other, rather than out in the field where work occurs. This perceived insularity creates the impression that management has little interest in the kind of effective, two-way communication that it professes to value.

3. Mid-level Managers as Change Agents

Although top management reports that it has made recent personnel decisions with the aim of selecting managers who will be effective agents of change, little appears to have been done to prepare mid-level management to fulfill this role effectively. To some extent, mid-level managers appear to be caught in an impossible situation. On one hand, they receive pressure from above to continually cut costs and maintain productivity with fewer resources. On the other hand, top-level management is equally insistent that the safety culture must be improved, high quality standards must be met, and procedural adherence must be enhanced. Under these intense and sometimes conflicting pressures, the managers are widely viewed by the workforce as reactive, out-of-touch, and ultimately counterproductive. As alluded to above, there is a widespread belief that all levels of managers spend a disproportionate amount of time in meetings talking with their peers, and too little time productively engaging the workforce.

The management agenda is seen as dominated by actual or perceived crises. Often

the responses to these crises are not well formulated, and rarely are front-line workers consulted for input. Frustrations build, especially in light of the pressure to get the work done on time, and an "us" vs. "them" attitude develops between the workers and the managers. When the traditional, cultural elements discussed above are merged with the bifurcated organization, it is easy to understand why issues and concerns might not be reported or might fail to receive the appropriate level of attention.

4. First Line Supervisors

Supervisors not only have primary responsibilities for the implementation of policy and procedures, but also are a focal point for the raising of issues and concerns. Within the Maine Yankee organization, however, supervisors generally appear poorly equipped to handle their roles successfully. Frequently, it appears, those employees with the best craft or technical skills tend to win promotion to the supervisory ranks. Yet the skill set needed for excellent performance in a technical discipline may have little relevance to supervisory responsibilities. In addition, the CAT found that supervisors tend to receive very little training for the non-technical aspects of their jobs, and that they are poorly integrated into the management team. For the most part, higher level managers appear not to communicate well with supervisors, who often feel "caught in the middle" when directed to implement policies and procedures that are resisted by the workforce. Supervisors have little substantive role in developing policies and procedures, and, as their paperwork burden grows, they increasingly feel alienated from, and even betrayed, by upper management. Not uncommonly, the response is to attempt to keep a low profile by deflecting and redirecting visible problems -- hardly a response that encourages the expression of worker concerns. It should be emphasized, however, that the problem involves organizational structure, at least as much as the individuals who occupy supervisory positions. Within the current organizational culture,

supervisors are indeed caught in the middle, and they are too disempowered to deal effectively with the pressures experienced from either above or below.

C. Deteriorating Organizational Relationships

Through most of its operating history, Maine Yankee appears to have been a tightly cohesive organization. Recently, however, the sense of unity has frayed. CAT interviews revealed multiple lines of perceived division: between employees in Brunswick and personnel in Wiscasset; between those working "inside the fence" and those working outside; between management and workers; and between various departments within the organization. Numerous employees attempted to date the beginning of the decline, and although few pointed to more than three years ago, most traced the onset of these schisms to before the 1995 outage. Significantly, however, nearly everyone thought that organizational unity and morale had deteriorated by the end of the re-sleeving outage, and that matters had continued to get worse in the current year. For obvious reasons, the outage produced elements of stress and anxiety. The future of the organization was at substantial risk, and the level of risk was not going to subside. The question surrounding the willingness of the Board of Directors to support the re-sleeving project eroded confidence in the future. Under some circumstances, shared interests and challenges cause organizations to become more unified and cohesive, but the opposite occurred at Maine Yankee. For a variety of reasons, this organization began to pull apart. The causes of this situation, which also tends to discourage acceptance of responsibility to raise issues and concerns, are multiple.

1. Distrust of Senior Management

Almost no one in the workforce believes that senior management has a plan or a vision that will enable the organization to control events as it moves to 2008 or beyond. Although top management in fact appears to be exploring a number of significant, and in some cases

innovative, approaches to sustaining plant operations, these are not well publicized. Perhaps they cannot be widely disseminated, but the resulting sense of vagueness and drift has a damaging effect not only on morale, but also on trust and credibility within the organization. In the eyes of many employees, top management should be attempting to persuade the Board of Directors that Maine Yankee is a valuable asset that would abundantly repay a more generous investment of resources. When management is seen as not pressing aggressively for such investment, or otherwise attempting to extend the life of the plant beyond 2008, many employees conclude that the company's leadership does not have their best interests at heart.

2. Organizational Rifts

As pressure mounts within the Maine Yankee organization -- to meet heightened standards, to avoid a mistake which could trigger a shutdown, etc. -- employees cite a decline in cooperation and teamwork among various departments. Many describe an inequitable distribution of responsibility and the shifting of blame to others as becoming increasingly common. More often than not, management is held responsible for this situation. Because there is no shared vision and support from above is perceived as minimal, workers can understand why some supervisors and managers are putting responsibility on others at every opportunity and attempting to protect their own reputations. Nonetheless, most of the workers do not like the lack of teamwork and cooperation, and they resent being placed in situations in which the lack of teamwork frustrates their efforts to complete their work efficiently.

The sense of organizational disunity has recently been exacerbated by management's decision to eliminate overtime pay for all exempt employees. Supervisors and section heads in the plant, in particular, are frequently assigned work hours in excess of the standard forty hour work week and are accustomed to receiving overtime pay. They resent the "revenue neutral"

redistribution associated with the new incentive compensation program that, in their view, undervalues the centrally important contributions of the employees who actually make the plant operate. The substance of the incentive plan coupled with the way implementation was handled has led to a strong sense by affected personnel "inside the fence" that they are not duly respected by corporate officials in Brunswick. Another line of division is thus heightened, and further encouragement is provided to engage in finger-pointing and responsibility-shifting, rather than acceptance of a personal responsibility for safety, productivity and the raising of issues and concerns.

VI. RECOMMENDATIONS

The primary purpose of the CAT was to determine the culture at the Maine Yankee site with respect to individuals raising issues and concerns. As mentioned throughout the preceding sections, the Team found that the atmosphere is conducive to the raising of concerns perceived as safety significant, but is not conducive to forthright and prompt reporting for issues and concerns which are perceived to have little or no safety significance.

Since this condition seems to be widespread, the CAT charter directed the Team to develop recommendations which would address the apparent causal factors. The dimensions of this challenge need to be clearly understood. The causal factors identified above were all cultural or otherwise bound up with entrenched organizational values, practices and attitudes. As a result, no "quick fix" is possible; no new program, policy, procedure or mechanism alone will do the job. Behaviors have to be changed, and over time, the behavior changes will lead to a new organizational culture.

To succeed in this effort, Maine Yankee's management will need to lead the way by word, deed and many reinforcing examples. Most basically, management will have to convince the

workforce that new policies, practices and attitudes are absolutely necessary for the organization to have a chance to be successful in the world of changing economic pressures, evolving industry standards and heightened expectations concerning safety and operating performance. To effect this type of change, management must engage and empower a workforce that is currently somewhat resistant to change -- especially change that is viewed as reflecting no more than a fiat of a disengaged management team. In order to be successful, management must regain the trust of Maine Yankee employees and develop a course of action that is seen as having reasonable involvement from those with the front-line responsibilities for implementing it.

In view of the complexity of the issues, many of the CAT's recommendations are only suggestive, and the list is not comprehensive. Moreover, because of the interconnections among elements of the prevailing culture, the Team's recommendations do not divide neatly into categories. They do, however, highlight some of the principal fronts along which corrective actions are warranted.

1. Safety must be seen by all as the paramount organizational value. Management must establish a lower threshold for raising safety issues and concerns and ensure that a uniform standard is consistently applied throughout the organization.

2. Expressions of workers concerns, including "people issues," need to be received in an open and forthright manner.

> People raising issues should be respected and recognized as concerned contributors to the potential success of the organization. Supervisors should be held accountable for bringing forward concerns raised with them that cannot be adequately addressed at their level. Well consolidated and integrated tracking systems should be developed to ensure that all expressed concerns receive a timely and appropriate response.

3. Management should promptly develop a vision around which the organization can rally. This vision should be clearly and forcefully articulated on every possible occasion.

4. Management should address other causes of perceived disintegration of organizational unity.

*Management must visibly demonstrate that it is in touch with, and cares about, workers' legitimate concerns. For example, management should reformulate and rename the committee to examine employee issues arising from the prospect of ultimate shutdown.

*Organizational policies, practices, and plans should be developed with more input from the organization, should be well thought out, should be effectively communicated, and should be implemented consistently.

5. Training and coaching should be increased for mid-level managers to enhance their managerial capabilities, especially their skills related to change management and communications.

Training in communications and the management of change is more important for managers than technical training. Within the current organizational structure, top management's expectations appear not to be communicated successfully through mid-level managers to the workforce, nor has change been introduced effectively. In seeking to address this problem, mid-level managers in particular need to understand that simply articulating a message will not achieve motivation or the desired change. More time needs to be spent in reinforcing the message and monitoring how it is received. Managers need to engage the workforce in a positive, constructive manner -- this is essential for effective change management.

6. A broader cross-section of the organization needs to be involved in identifying and solving problems as well as in enhancing procedures.

For the organization to function successfully as a team, steps are needed to ensure that management and workers share at least basic understandings of technical issues, practical difficulties, and relative priorities. To this end, management must combat the perception that it is isolated and out-of-touch, and must expand the consultative process that necessarily precedes revision of practices and procedures. If mid-level managers lack the resources to develop workable policies and practices that can be embraced by the workforce, resources should be provided.

7. Supervisors need to be more fully integrated into the management team.

*Management should select and train supervisors to effectively carry out their responsibilities. Among other things, management needs to better define the managerial skills required by first-line supervisors; promote workers to supervisory

positions with those skills in mind; provide more adequate training in management skills to current supervisors as well as those promoted in the future; assess current supervisors' competence for the exercise of managerial responsibilities; and, where necessary, remove those who lack the requisite skills from supervisory positions.

*Supervisors need to be involved in the management dialogue through which organizational values are distilled into practices, procedures, and expectations. This will make supervisors more effective conduits for the expression of worker concerns.

8. The Maine Yankee workforce needs to embrace the revised organizational priorities.

A significant gap has developed between management and much of the Maine Yankee workforce. Part of the division appears to involve disparate senses of organizational priorities, and part undoubtedly involves differing perceptions of what can reasonably be accomplished given existing systems, procedures, and resources. While management needs to provide the elements of leadership, the workforce needs to understand the changing environment and alter some specific behaviors. The workforce should:

*Report issues and concerns immediately. Self-reporting is best, but making sure that issues and concerns get raised and pursued is essential.
*Monitor and check each other accurately. Ensure work is done properly and constructively. Look out for co-workers.
*Accept full accountability for individual safety and radiation exposure. Recognize that barriers are in place to assist, but ultimately the individual is responsible for every aspect of his/her performance.
*Stress teamwork in all daily activities. Recognize that the best chance for long term operation of the plant is through cooperation and mutual support.
*Learn about the external factors which impact the site and are driving changes within the industry.
*Fully commit to the use of, and adherence to, procedures. If procedures affect work adversely, help find ways to get them corrected efficiently. Provide input into procedures to make them the best possible.
*When there is a conflict between the quality of work and the schedule, prioritize quality at the top — do not cut corners or take short cuts. Stop and inform supervision.

9. The senior management team should consider ways to strengthen the Human Resources Section.

Management believes some strides have been made in this direction, but it is clear that confidence and trust in the Human Resources Section need to be improved. Many of the "people issues" arising within Maine Yankee should be dealt with through the Human Resources Section.

10. Management should clarify the intended role of the Worker Concerns Program and modify it as appropriate in light of clarified expectations.

*One issue needing clarification is whether the program is available only for issues with a relatively high threshold of seriousness.

*Another issue is the degree of confidentiality employees can expect when they raise a concern within the program. At a minimum, employees should be apprised of the degree of confidentiality that can reasonably be assured them and, if they wish it, should be entitled to as much confidentiality as practicable.

*The role of the chain-of-command within the program should be clarified so that practice and policy are consistent.

*Management should at least consider restructuring the Worker Concerns Program so that it would report directly to the President/Chief Executive Officer rather than the Quality Programs Department.

APPENDIX A

CULTURAL ASSESSMENT TEAM CHARTER

Purpose

The purpose of the team is to assess whether, or to what extent, Maine Yankee may have a culture that discourages employees from raising concerns, particularly nuclear safety concerns.

Team Composition

The team shall be comprised of independent outside consultants experienced in organizational development or psychology, human resources, and the law. Team membership will be composed of:

- Jackie Chouinard, Human Resources Consultant
- Bob Bradford, Rohrer, Hibler & Replogle, Inc., Dallas Office
- Richard H. Fallon, Esq., Professor of Law, Harvard Law School
- Jeff Jefferies, Paridigm Consulting Services

Objectives

1. The team is to assess whether there is a culture that fosters openness and communication by workers or one that discourages such communication.

2. The team shall evaluate the effect of the culture on utilization of the Maine Yankee Worker Concern Program and employees' perceptions of the Program's effectiveness and shall make recommendations for improvement.

Duties

1. The team shall report its findings to the President of Maine Yankee no later than May 31, 1996.

2. The team coordinator shall be responsible for coordinating team activities, schedules and implementation of this charter with the assistance of Robert M. Hayward, Acting Manager, Quality Programs Department.

3. The team shall provide immediately to the Manager of Quality Programs any issue that appears to the team to have potential safety significance.

4. The team shall determine whether personnel are willing to bring forth problems concerning plant personnel, processes, safety issues or other concerns.

5. If a culture or atmosphere which does not foster open communications is found, the team shall determine the apparent cause of the condition(s), and provide recommendations to address any identified causal factors.

6. The team shall satisfy the above objectives by conducting interviews of a representative sample of personnel employed throughout the company. In addition, the group will focus, in particular, on the environment within the Radiation Protection Department. The team shall sample an appropriate number of personnel to be interviewed to accomplish its objectives. The team may conduct group interviews as it seems fit. The interviews shall be documented so that personnel shall remain anonymous to the extent that personnel request anonymity or to the extent that the team believes anonymity will further its research. The team shall conduct other research as deemed necessary, including review and analysis of documents and other industry concern programs.

7. The team's legal member shall coordinate all documents prepared by the team. The documents, except for the final report, shall be considered privileged and proprietary. The team shall provide a final report on information gathered. The report shall include findings and extent of condition, and recommendations for improvement.

Charles D. Frizzle
President and Chief Executive Officer

APPENDIX B

Interview Organizer (with Introductory Points and Questions)

Interviewer:

Other interviewer (if group interview):

Date and time of interview:

Employee or employees interviewed and their positions in the organization:

Other pertinent information:

Possible Introductory Points

1. Voluntariness. From our perspective, the interview should be completely voluntary; the interviewee may terminate the session at any time.

2. Interviewees' understanding of our project. We might (or might not) inquire what the interviewees know about our project, so that we can tailor our responses and explanations to their current understandings.

3. The nature of our project.

   a. Some recent trends have led management to believe that some employees perceive the climate at Maine Yankee as not friendly to reporting of safety and other worker concerns.

   b. We have been commissioned to find out if there is a problem that could lead to failures to report safety and

other concerns.

c. We are an independent and diverse team. No team member is a part of the Maine Yankee Organization. We have significant experience and capabilities in the fields of psychology, human relations, law, and management.

4. Nature and aims of the interview. We're going to ask some relatively open-ended questions about the methods and processes used to raise safety and other issues, and ask you to respond by telling us as much as you know.

We're not necessarily looking for information related to specific events or incidents. If information should be brought up that requires immediate reporting in the interests of safety, it will be handled in accordance with appropriate processes and requirements.

5. Our goals. If we find there is an actual or developing problem involving the climate for raising safety and other concerns, we will make recommendations about how to improve the climate or otherwise correct the conditions here.

6. Confidentiality. We will feel free to share all information communicated in the interview, but will not use names in our report or briefings, and will otherwise attempt to preserve anonymity if requested to do so.

7. Sharing our conclusions. Management has assured us that the conclusions of our report will be shared with staff.

8. Randomness of interview assignments. Both group and individual interview assignments are random.

Sample Questions

1. **Current programs: understanding and effectiveness.**

What methods exist for reporting worker concerns?

Nuclear and industrial safety concerns?

Other concerns?

What is the mechanism for reporting personnel errors?

What are the responsibilities of supervisors and other officials in the chain of command when concerns are raised with them? (Note: this is an especially important question to raise with supervisors, to ascertain whether they understand their responsibilities.)

How effective are existing reporting methods?

In particular, what expectations do you have of the Worker Concerns Program--especially insofar as it permits the raising of concerns outside the line organization--with respect to timeliness, feedback, confidentiality, and resolution?

How would you feel about Maine Yankee posting worker concerns and responses?

2. Cultural factors affecting reporting

How would you describe the general climate at Maine Yankee for reporting safety and other concerns?

How would you describe management's expectations with respect to raising safety and other concerns?

How are those expectations communicated?

Are actions consistent with articulated expectations?

How do your peers usually react to people who raise safety and other concerns?

How does supervision react?

Is the reaction pretty consistent?

If not, describe relevant differences.

3. **Personal attitudes toward reporting.**

If you wanted to raise an issue, how would you do it?

Why would you do it in that way?

Are there any ways of raising concerns that you would specifically <u>not</u> want to use?

If so, why?

How does the potential reaction of peers affect your willingness to raise a concern?

How are you affected by the potential reaction of your immediate supervisor?

The potential reaction of people further up the chain of command?

How does your supervisor support or discourage the raising of safety issues?

4. Perceptions of the general culture

How, in the most general terms, would you describe the work environment at Maine Yankee with respect to such matters as morale, respect or lack of respect, communication or lack of communication, and so forth?

Has it changed recently? If so, how?

What do you regard as the strengths of the organization?

What are its weaknesses?

If you were in charge of the site, what changes would you try to make?

What do you see as the future of Maine Yankee?

What issues should management be working on?

Do you know what you need to know about the organization?

How do you get most of your information?

5. Management

What is the management style the organization now uses? OR: How does management relate to the workforce?

Is management's current style effective?

What changes would you recommend?

Do you believe that management is responsive to safety issues? Other issues of concern to you?

Do you trust management?

6. Hopes and recommendations (OPTIONAL)

What do you hope the team will say?

What do you hope that it will not say?

What recommendations would you make to improve the handling of employee issues and concerns?

Central Issues

Although the set of "sample questions" is intended only to be suggestive, there are certain central issues that should be addressed in every interview, to provide the foundation for our report and recommendations. These include:

1. Worker and supervisor awareness of existing programs for reporting concerns

   Supervisor understanding of their responsibilities

2. Perceived effectiveness of current programs, especially including the Worker Concerns Program

3. Cultural factors directly bearing on reporting of worker concerns

   Attitudes of supervisors

   Prevailing values within the organization

4. Perceptions of the general culture at Maine Yankee that may have an indirect effect on willingness to report

   Morale

   Communications

5. Perceptions of management

6. Recommendations for change and improvement

   Possibilities for better coordination of existing programs

Exhibit D

Overtime and Staffing Problems In the Commercial Nuclear Power Industry

March 1999

My group spends a lot of time in the field, and so does the other groups and we see problems -- working hours, overtime, fatigue. There are three quick examples that we're in between having a standard on how to deal with that and a problem that we know is lurking out there.

NRC Staffer to Advisory Committee on Reactor Safeguards December 5, 1996

UNION OF
CONCERNED
SCIENTISTS

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After the Three Mile Island accident, the Nuclear Regulatory Commission (NRC) recognized the role that worker fatigue could play in an accident. Unfortunately, that recognition did not lead to the problem's resolution.

An extensive review of NRC documents dealing with fatigue problems found a clear pattern of unenforceable ambiguity. The NRC's concern about worker performance problems caused by fatigue seems to be limited to their meekly encouraging plant owners to handle it. The NRC's inept treatment of this issue is baffling when compared to how successfully the agency dealt with another issue having similar impacts on worker performance – namely, substance abuse. For that issue, the NRC implemented a rule that has virtually eliminated substance abuse problems by nuclear workers.

Anecdotal evidence supports the conclusion of NRC ineffectiveness on the fatigue issue. Three members of the NRC's regional staff indicated that the agency feels that as long as nothing bad happens, it will take no action. That attitude, if reflective of NRC policy, would seem to be designed to – at best – prevent the *second* major reactor accident. It contradicts the NRC's mission, as defined by Congress, of providing adequate protection against the *next* major reactor accident.

The electric utility industry is undergoing restructuring. Nuclear power plant owners are cutting staffing levels in their efforts to generate electricity at competitive prices. As a result, workers at nuclear plants are working more overtime. For example, operators at a Midwest nuclear power plant logged 50,000 overtime hours in just one year's time – 1997. The worker fatigue problems are likely to get worse unless the NRC takes action to deal with the issues.

The full rationale for NRC's failure to meaningfully address overtime and staffing issues is not known, but a major part is simply "that nothing bad has happened yet." Using this unsound logic, the emergency core cooling systems and containment buildings at the nation's 103 nuclear power plants could be permanently removed since few events have required their use. Unlike the purported one in a hundred-thousand year or one in a million year chances of an accident requiring emergency core cooling systems and the containment building, worker fatigue is a minute by minute challenge to safe plant operation.

The NRC must establish clear requirements for working hours that reduce the potential for weary workers making grave mistakes.

How Workers Affect Nuclear Safety

According to information provided to the NRC by nuclear plant owners, 50 to 80 percent of serious safety problems involve worker errors.[1] The NRC's analytical staff reviewed reports submitted by plant owners and NRC inspectors and concluded that the sequence of events leading to a major plant accident would most likely be initiated by a worker mistake.[2] Following its review of plant-specific safety assessments, the NRC staff concluded, "human actions are clearly important contributors to operational safety" and "human error can be a significant contributor to [serious reactor accidents.]"[3] Thus, nuclear plant workers make mistakes and their mistakes can have very serious safety implications.

What causes nuclear plant workers to make mistakes? While there is no single cause for the mistakes, fatigue is responsible for some significant ones. For example, the NRC reported that in October 1990, three workers at Braidwood Unit 1 in Illinois, were sprayed with 180°F water – one individual received second degree burns – from the reactor coolant loop when plastic tubing used for testing burst open. Over 600 gallons of water drained from the reactor coolant system before the leak could be stopped. NRC inspectors concluded that fatigue from excessive overtime was a main contributor to this event.[4]

How Fatigue Affects Workers

Researchers have consistently found what Thomas Jefferson might have considered self-evident – that fatigue causes workers to make more mistakes and to perform less reliably.

The accident at Three Mile Island – the worst commercial nuclear plant accident in US history – occurred in the early morning hours of March 28, 1979. The following year, the NRC reported:

> Studies indicate that with fatigue, especially because of loss of sleep, an individuals detection of visual signals deteriorates markedly, the time it takes for a person to make a decision increases and more errors are made, and reading rates decrease. Other studies show that fatigue results in personnel ignoring some signals because they develop their own subjective standards as to what is important, and as they become more fatigued they ignore more signals.[5]

The last part is particularly disturbing because it suggests that well-founded procedures and layers of emergency equipment can be defeated by weary workers discounting warning signs.

Concern about fatigued workers is not confined to the nuclear industry. Research in the aviation industry found that fatigue:

- slowed individuals' reaction time,
- impaired people's problem-solving ability,
- made people more likely to take short cuts,
- made people more willing to accept higher than normal levels of risk.[6]

Here again, is the disturbing finding that fatigue prompts otherwise responsible people to take shortcuts and high risks.

The aviation study concluded that fatigue made it harder for people to solve problems. In 1992, researchers at Canada's Defence and Civil Institute for Environmental Medicine quantified this negative impact. They reported that after 18 hours awake, people's problem-solving ability declined by 30 percent.[7] Note that this degradation occurs after the time awake not just the time on the job.

Although fatigue was not shown to be a factor in the space shuttle *Challenger* explosion, the Rogers Report did find that worker fatigue had contributed to prior near-misses.[8] One specific example cited was the aborted launch of shuttle mission 61-C on January 6, 1986. Five minutes before the launch, workers misinterpreted a valve indication failure in the automatic fueling sequence. This caused the undetected loss of nine tons of the liquid oxygen fuel. A fortunate side effect of the loss was a drop in temperature to the shuttle main engines, but this degraded condition was noted only 31 seconds before the launch. The launch was aborted. The investigation found two significant points:

- Worker fatigue was one of the major factors of the error. The workers were 11 hours into their third consecutive 12 hour midnight shift when the error was made.
- Had the error not been discovered and the launch aborted in the final seconds of the countdown, it was seriously doubted that the shuttle would have reached orbit.

The Rogers investigation was very critical of the long hours worked by shuttle subcontractors because, in part, they regularly exceeded the recommended limits of an NRC report[9]. The ironic part is that NRC never implemented its own recommendations.

Worker fatigue has even tarnished the golden arches. In 1983, an Oregon jury awarded $400,000 to the driver of a car struck by a McDonalds employee who had worked three shifts within a 24-hour period. The jury determined that McDonalds failure to control working hours "unreasonably created a foreseeable risk of harm."[10]

The effects of fatigue on nuclear safety are best summarised in the NRC's own words:

> The safety of nuclear power plant operations and the assurance of general public health and safety depend on personnel performing their jobs at adequate levels. Research on extended working hours indicates that the performance of individuals will degrade without adequate rest after long periods of work. Fatigue can degrade an operator's ability to rapidly process complex information such as that presented by off normal plant conditions. In addition, fatigue may jeopardize the ability to respond in a timely fashion. Furthermore, performance errors are more likely to occur as a result of lapses in short-term memory. Because individuals performing safety-related duties may be required to respond quickly to a plant emergency, it is important for plant management to carefully exercise control over overtime practices in order to ensure that plant personnel perform adequately.[11]

McDonalds was held accountable because it failed to properly deal with a foreseeable risk of harm. The NRC acknowledges that

worker fatigue represents a risk to nuclear plant safety. What have they done about it?

What NRC Did About Fatigue

The NRC first attempted to deal with the fatigue problem with a policy statement on overtime issued in 1980.[12] The policy contained more restrictive working hour limits than currently exist, but even these 'limits' were diluted because they were presented as recommendations rather than as requirements. The policy also outlined the licensee's responsibility to "provide a sufficient number of trained personnel who are in the proper physical condition to operate and maintain the plant."

In 1982, the NRC sent all nuclear power plant owners information which forms the agency's current overtime policy. The major points of the policy are:

- Plant owners must have written procedures that formalize the working hour guidelines and prevent situations where fatigue could reduce the ability of operating personnel to keep the nuclear plant in a safe condition. The procedural controls should assure that personnel are not in a fatigued condition while at work that could significantly reduce their mental alertness or their decision-making ability.
- A sufficiently large work force should be used to prevent routine heavy use of overtime. The objective is a normal 8-hour day, 40-hour week while the plant is operating. If unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown, the following guidelines shall be followed:
  1. An individual should not work more than 16 hours straight.
  2. An individual should not work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven-day period.
  3. A break of at least 8 hours should be allowed between work periods.
  4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on shift.
- If very unusual circumstances arise that require deviation from the guidelines, such deviation shall be authorized by the plant manager, his deputy, or higher levels of management.

After the Three Mile Island accident, the NRC required nuclear power plant owners to revise their operating licenses to include administrative controls on staffing levels and working hours. Although the administrative controls language was somewhat ambiguous, its placement in plant operating licenses meant that the NRC focused at least some attention to the matter.

Beginning in 1996, NRC undermined what little rigor remained in overtime regulation by allowing plant owners to re-revise their operating licenses, this time to *remove* the administrative controls on staffing levels and working hours. For example, the NRC issued a Safety Evaluation Report for San Onofre Units 2 and 3 to allow the overtime controls to be removed from Tech Specs. The basis was "that few events at U.S. nuclear plants have been attributed to inadequate control of working hours."[13]

How NRC Handled Substance Abuse

Ten years ago, the NRC issued the Fitness for Duty rule to address substance abuse in the nuclear power industry. The NRC imposed this rule because "scientific evidence is conclusive that significant decrements in cognitive and physical task performance results from drug and alcohol usage."[14]

During 1997, researchers at the University of Southern Australia compared the effects from fatigue to those from alcohol consumption.[15] They used standard eye-hand coordination test methods. After 17 hours awake, the decline in performance was equivalent to a blood alcohol content (BAC) of 0.05 percent (the legal limit set by the NRC for access to nuclear power plants is a BAC of 0.04 percent). At 24 hours awake, performance had decreased to a level corresponding to a BAC of 0.10 percent.

Curiously, although conclusive scientific evidence shows that fatigue causes measurable drops in cognitive and physical task performance and the NRC's own records are replete with examples of safety problems caused by weary workers, the agency views fatigue with in an entirely different light from substance abuse.

During the public comment period for the fitness for duty rulemaking, one person observed that fatigue could impair worker performance. Another commenter noted that workers could be disciplined or fired for errors due to fatigue.

The NRC responded to these comments by acknowledging that fatigue was an important issue but claimed that sound management practices could be expected to be more effective than prescriptive regulations. Because it is more economical to get more work out of existing staff than to hire additional workers, the NRC's logic is wrong. The agency also did not explain why sound management practices would be inadequate to handle substance abuse. The NRC also took credit for the part of the rule that requires plant owners to ensure that workers are not impaired from any cause, arguing that fatigue was covered by this language. Given that this wording is even more nebulous than the NRC's guidance on overtime, the logic is fallacious. The NRC's guidance to inspectors when auditing fitness for duty programs at nuclear power plants makes no – zero – mention of fatigue and focuses solely on substance abuse.[16]

How effective is the fitness for duty rule? With respect to substance abuse at nuclear power plants, it has been very effective. Fewer than one percent of the 296,625 drug and alcohol tests administered to nuclear plant workers during 1996 and 1997 yielded positive results.[17] The rule has been less effective with respect to fatigue at nuclear power plants.

Conclusions

Independent studies and nuclear industry experience both show that fatigue degrades the performance of workers. The NRC reports that worker mistakes can lead to serious nuclear plant accidents. The NRC attempted to limit fatigue among nuclear plant workers through restrictions on overtime and staffing levels, but these efforts have been ineffective.

The NRC's ineffectiveness in handling the fatigue problem is hard to understand given the agency's success in addressing substance

abuse problems. The NRC implemented a fitness for duty rule more than ten years ago that has effectively reduced substance abuse problems among nuclear plant workers. The NRC has been unable, or unwilling, to effectively address the fatigue issue.

The explanation for NRC's failure to address fatigue problems levels is not known. It may simply be that the agency feels "that nothing bad has happened yet" as if its mission were to protect the public from the *second* major reactor accident. Using this logic, the emergency core cooling systems and the containment buildings at nuclear power plants could be permanently removed since few events, *so far*, have required their use.

The restructuring of the electric utility industry makes proper control of worker fatigue more important. Nuclear power plant owners are cutting staff sizes as part of their efforts to generate electricity at competitive prices. As a result, the remaining workers are putting in longer and longer days as they pick up the load from those who have left. Fatigue problems in the nuclear power industry must be resolved soon.

Unlike the purported one in a hundred-thousand year or one in a million year chances of an accident requiring emergency core cooling systems and the containment building, worker fatigue is a minute by minute challenge to safe operation. Actions are said to speak louder than words, but in this case, the NRC's inaction speaks the loudest.

Recommendations

The NRC must take actions to address worker fatigue at nuclear power plants. The NRC could either apply its fitness for duty rule or implement a comparable rule. In any case, the NRC must establish clear requirements for working hours that reduce the potential for weary workers making grave mistakes.

Nuclear power plant owners must develop and consistently implement administrative controls to protect their workers from conditions causing fatigue. The NRC's working hour limits must <u>not</u> be routinely abused.

[1] Nuclear Regulatory Commission, Transcript of 452nd Meeting of the Advisory Committee on Reactor Safeguards (ACRS), April 30, 1998.
[2] Nuclear Regulatory Commission, Information Notice No. 92-36, "Intersystem LOCA Outside Containment," May 7, 1992.
[3] Nuclear Regulatory Commission, NUREG-1560 Vol. 1, Part 1, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," October 1996.
[4] Nuclear Regulatory Commission, Information Notice No. 91-36, "Nuclear Plant Staff Working House," June 10, 1991.
[5] Nuclear Regulatory Commission, Circular No. 80-02, "Nuclear Plant Staff Working Hours," February 1, 1980.
[6] Remi, Joly, Transport Canada, "A Study of the Impact of Shiftwork and Overtime on Air Traffic Controllers: Phase I," TP 12257E. October 31, 1994..
[7] Angus, R.G., Pigeau, R.A., and Heselgrave, R., "Human Performance and sleep research: from the field to the laboratory," in C. Stampi (ed) *Why We Nap*. Boston: Birkhauser, 1992, pp 217-241.
[8] "Report of the Presidential Commission on the Space Shuttle *Challenger* Accident, Vol. II, Appendix G, June 1986.
[9] Nuclear Regulatory Commission, "Recommendations for NRC Policy on Shift Scheduling and Overtime at Nuclear Power Plants," NUREG/CR-4285 (PNL-5435), July 1985.
[10] Ed Coburn, "Managing the Costs of Worker Fatigue," *Risk Management News*, July 29, 1996, pp. 3-4.
[11] Nuclear Regulatory Commission, Information Notice No. 91-36, "Nuclear Plant Staff Working Hours," June 10, 1991.
[12] Nuclear Regulatory Commission, Circular No. 80-02, "Nuclear Plant Staff Working Hours," February 1, 1980.
[13] Nuclear Regulatory Commission, Safety Evaluation Report, "Issuance of Amendment for San Onofre Nuclear Generating Station," February 9, 1996.
[14] Title 10 Code of Federal Regulations, Part 26
[15] *Nature*, Vol. 388, 17 July 1997, pg 235
[16] Nuclear Regulatory Commission, Inspection Manual, Inspection Procedure 81502, "Fitness for Duty Program"
[17] Nuclear Regulatory Commission, Information Notice No. 98-39, "Summary Of Fitness-For-Duty Program Performance Reports For Calendar Years 1996 And 1997," October 30, 1998.

1 JUDGE BECHHOEFER: Checking with the
2 reporter, were the other testimonies that are being
3 bound into the record given to you in exhibit form or
4 were there give to you in --
5 COURT REPORTER: Yes. I have Licensee
6 Exhibit 1 and Licensee Exhibit 2. So we can make this
7 CAN 1.
8 JUDGE BECHHOEFER: Okay. We'll identify
9 this as CAN Exhibit 1. The reporter will treat it as
10 he had treated the other exhibits.
11 MR. SILBERG: Just to clarify, we are
12 binding these into the transcript?
13 JUDGE BECHHOEFER: Yes.
14 MR. SILBERG: Okay.
15 JUDGE BECHHOEFER: Yes. Mr. Lochbaum, I
16 have a few questions. In your resume -- or in your
17 testimony, you stated that you worked as a consultant
18 to NYPA from 1992 through 1995. Were any of your
19 assignments or duties financially related?
20 MR. LOCHBAUM: No. I was working as a
21 consultant in the Design Engineering Group, working on
22 design basis reconstitution development. That didn't
23 have any financial implications or anyone on the
24 financial clock. I know at the time, from the tail
25 end of that period, the Entergy Corporation was

1 looking to purchase the plants, but I was not involved
2 in those dealings in any way whatsoever.
3 JUDGE BECHHOEFER: Well, do any of your
4 activities, with respect to NYPA, involve the
5 particular issue that you're addressing here, and that
6 is capacity factors? And I refer you to, I guess,
7 paragraph 8 of your prepared testimony or declaration.
8 Did any of those activities -- were you previously
9 involved in anything that might affect your opinion on
10 the ability of the plants to reach -- to achieve a
11 certain capacity factor?
12 MR. LOCHBAUM: No. My activities were
13 working on the design basis project. They were not
14 related to the operational -- at least directly
15 related to the operational performance of either unit.
16 The experience that I refer to in paragraph 8 of my
17 testimony was mainly talking about experience at the
18 Maine Yankee and some subsequent plants and some of
19 the problems they had, not the experience at either
20 Indian Point 3 or Fitzpatrick.
21 JUDGE BECHHOEFER: Now, could you define
22 -- let's see, the documents that you reviewed, are
23 they set forth in --
24 MR. LOCHBAUM: Yes. The response of
25 paragraph 8 is the --

1 COURT REPORTER: We're losing you, Mr.
2 Lochbaum.
3 MR. LOCHBAUM: And the other documents I
4 reviewed are the exhibits or attachments to my
5 declaration of testimony.
6 MR. SILBERG: Judge Bechhoefer, could he
7 -- I'm not sure the reporter got that with the gap.
8 Could Mr. Lochbaum just repeat that answer?
9 JUDGE BECHHOEFER: Yes. Could you repeat
10 that. I want to make pretty clear what sources of
11 information you used as a basis for your testimony.
12 MR. LOCHBAUM: Yes. The documents I
13 reviewed are cited within the testimony, on the
14 footnote, on the page that has paragraph 8, which is
15 page 2. It is NUREG 1350, issued by the Nuclear
16 Regulatory Commission. It's the Information Digest,
17 2000 edition. The other documents that I used for my
18 testimony are provided as exhibits to the testimony.
19 There's the Maine Yankee Independent-Based Assessed
20 Team report, issued by the Nuclear Regulatory
21 Commission in October of 1996; the Cultural Assessment
22 Team report, issued in May of 1996; and a report
23 prepared by the Union of Concerned Scientists and
24 issued in March of 1999. It's on overtime and fatigue
25 in the nuclear industry.

1 JUDGE BECHHOEFER: Now, do you know --
2 your opinion is that the 85 percent capacity factor is
3 uncertain. Is this likely to be different by more
4 than the margin of error, that the licensees, I think,
5 have conceded, a company's such projections?
6 MR. LOCHBAUM: I believe so, because the
7 data I looked at was independent of any company's
8 margin of error. It was just looking at the overall
9 industry's performance over the '94 to '99 period.
10 And as the testimony indicated, more plants failed to
11 achieve an 85 percent capacity factor than were able
12 to attain that or higher. So it appears uncertain
13 that the projections will be able to be achieved.
14 JUDGE BECHHOEFER: Now, in paragraph --
15 let's see -- in paragraph 9C, you state that Indian
16 Point 3 had more annual capacity factors under 85
17 percent, four, than at or above 85 percent, two, your
18 number two. Do you know what the relative time
19 periods were for those projections for when was it
20 under 85 and when was it over?
21 MR. LOCHBAUM: Yes. It was under 85 in
22 the years 1994, 1995, 1996, and 1997. And it was over
23 85 in the years 1998 and 1999.
24 JUDGE BECHHOEFER: Does this indicate some
25 sort of a trend to you that would indicate that maybe

1 the reactors are doing better -- or the licensees are
2 doing better as the years progress and have learned
3 something over time perhaps?
4 MR. LOCHBAUM: There was -- that would be
5 eight billion that could be drawn from the data, but,
6 again, by looking at the overall industry's
7 performance, again, I go back, as many, or in fact,
8 slightly more annual capacity factors were below 85
9 than above 85. So it's clearly possibly to achieve 85
10 percent power, but it means less certain that such
11 performance can be sustained for a long period.
12 JUDGE BECHHOEFER: Now, I have the same
13 essential question concerning Fitzpatrick about the
14 capacity factors. I guess it's paragraph 9E --
15 MR. LOCHBAUM: Yes.
16 JUDGE BECHHOEFER: -- said that they had
17 more under, four, than at or above, two. Do you know
18 what the time frames for those capacity factors are?
19 MR. LOCHBAUM: Yes. At Fitzpatrick, the
20 annual capacity factor was above 85 percent in the
21 years 1997 and 1999 and was below 85 percent in the
22 other four years -- 1994, 1995, 1996, and 1998.
23 JUDGE BECHHOEFER: Now, do you have --
24 you've listed a bunch -- you said 19 instances -- this
25 is at paragraph 9J -- 19 instances where a reactor

1 unit had an annual capacity factor of zero. Now, of
2 the 19 units, were any of these either Indian 3 or
3 Fitzpatrick?
4 MR. LOCHBAUM: Yes. One of those 19 years
5 was Indian Point 3. In the year 1994, they had a zero
6 capacity factor. It was basically shut down the
7 entire year. Fitzpatrick did not have any zero years,
8 zero capacity factor years during this period.
9 JUDGE BECHHOEFER: And the other 18, they
10 were what, other reactors?
11 MR. LOCHBAUM: Yes. For example, the D.C.
12 unit 1 and unit 2 were both shut down in 1998 and 1999
13 for the entire year, so they had fewer capacity
14 factors for those years. And the other 14 zero years
15 were plants like that or instances like it.
16 The reason I included that was to show
17 that it's not beyond the realm of possibility that
18 these plants could have a zero percent capacity
19 factor. I think that represented about three percent
20 of the overall data points during that six-year
21 period.
22 JUDGE BECHHOEFER: Now, in paragraph 10,
23 you refer specifically to an example at the Maine
24 Yankee Plant. Why did you pick Maine Yankee, only
25 because of the resulting factor or were there other

1 circumstances that you believe should make Maine
2 Yankee comparable, to some extent? And why should we
3 look at Maine Yankee as distinguished from others?
4 MR. LOCHBAUM: The reason I thought Maine
5 Yankee was relevant in this proceeding was that the
6 configuration between the Maine Yankee Atomic Power
7 Station and its owner, Central Maine Power, was
8 similar -- although not exactly the same, it was
9 similar to a limited liability corporation. And the
10 concerns identified by the Nuclear Regulatory
11 Commission at Maine Yankee about the cash flow would
12 mean the Company -- or the Plant site and its mother
13 company seem to be relevant to the proceedings of
14 whether there would be cash flow retained for the
15 programs that are necessary to maintain adequate
16 safety margins at a nuclear power plant.
17 Unfortunately, because of Maine Yankee's
18 condition, the NRC didn't pursue those concerns all
19 the way to their end, because the Plant owner decided
20 to close the Plant in progress, basically. But I
21 still think the concerns that the NRC raised at Maine
22 Yankee were valid and applicable to the proposed
23 configuration at Indian Point 3 and Fitzpatrick.
24 JUDGE BECHHOEFER: Well, did you look at
25 the experiences of any other Entergy-owned reactors?

1 MR. LOCHBAUM: Not recently. In 1998, we
2 looked at the River Bend Plant, which was the newest
3 -- at that time, it was the newest of the Entergy
4 nuclear plants. That review was documented in a
5 report that's not submitted as an exhibit, but we
6 issued a report in June of 1998, titled, "The Good,
7 the Bad, and the Ugly." What we learned from that
8 exercise, looking at River Bend, was that it had a
9 highest percentage of problems, safety problems caused
10 by personnel error of any of the plants we looked at.
11 It's percentage was -- 68 percent of its safety
12 problems involved personnel error, whereas the average
13 of the plants we looked at was only 35 percent.
14 There's a more recent NRC inspection
15 report, dated December 6, 2000. It's NRC Inspection
16 Report Number 50-458/00-14. The NRC inspectors
17 documented that the Plant had 27 performance problems
18 reported over a 12-month period, which seems to
19 indicate that the findings we had in 1998 are still
20 present at the River Bend Plant.
21 JUDGE BECHHOEFER: Now, in paragraph 11,
22 you refer again back to Maine Yankee and some of the
23 workers' fears there. And I wondered whether that
24 type of thing -- that you know of that type of thing
25 in other Entergy reactors, Entergy-operated reactors?

1 MR. SILBERG: Judge Bechhoefer, I rarely
2 object to a question from a Presiding Officer, but
3 since the Presiding Officer is the only one asking the
4 questions, I really think that this is an example of
5 why allowing safety issues in is going to create an
6 improper record. We're now hearing testimony about
7 documents that were never mentioned, that we had no
8 opportunity to look at, we still don't have an
9 opportunity to look at, that go beyond this witness'
10 direct testimony, beyond CAN's written statements,
11 beyond anything that is coming in at the last minute
12 on an issue which we believe is improper at all.
13 And I just wish that the record will
14 record my objection to going into these issues. I
15 think it's a good example of why the motion to strike
16 was properly filed and should have been granted. And
17 since this is a record that's going to the Commission,
18 I would like the record to reflect that objection.
19 JUDGE BECHHOEFER: I think, at this stage,
20 I will overrule that objection. I recognize that it
21 may be not as closely relevant as it might be, but the
22 Licensee did mention at one point the progress they
23 had made with respect to River Bend, and I think
24 that's close enough to permit you to answer the
25 question. I don't know how much -- how relevant we'll

1 find it or how much weight to give it, but you may
2 answer.
3 MR. LOCHBAUM: Thank you. I'm not aware
4 of any problems at any of the Entergy plants related
5 to the concerns I addressed in paragraph 11 of my
6 testimony. The reason I provided paragraph 11 was
7 because I thought the proposed configuration being
8 sought for Indian Point 3 and Fitzpatrick are moving
9 towards the Maine Yankee model that's described in
10 paragraph 11 in the Cultural Assessment Team report,
11 which would seem to move towards a situation where
12 workers might be fearful about raising safety issues.
13 It wasn't that I was implying or inferring that either
14 of these sites currently has that type of atmosphere.
15 Rather, that it was a plan to move towards the kind of
16 environment where Maine Yankee had problems in the
17 past.
18 JUDGE BECHHOEFER: At this stage, that's
19 all the questions that I had personally prepared of
20 Mr. Lochbaum. But I'm going to invite parties to
21 suggest other questions I might ask, and I think I
22 have authority to do this right in the rules.
23 MR. SILBERG: If I could address that,
24 Judge Bechhoefer.
25 JUDGE BECHHOEFER: I know, but let me

1 refer you to -- let me give you the specific section.

2 MR. SILBERG: 2.13-20 is the section that

3 you're referring to, A3.

4 JUDGE BECHHOEFER: I'm basically relying

5 on the authority in Section 13-22-B.

6 MR. SILBERG: Okay. Can I address that?

7 JUDGE BECHHOEFER: You may.

8 MR. SILBERG: One of the reasons that I'm

9 doing this, frankly, is because this is the first of

10 these kinds of proceedings. I think there will be

11 more. I think it's important that the rules for this

12 kind of case be established. This record will go to

13 the Commission, and I think it's important that the

14 Commission give all the parties guidance as to whether

15 this is the right model to follow or whether another

16 model ought to be followed.

17 Subpart M was created in order to set up

18 a different hearing regime than the typical ASLB

19 hearings in Subpart G. It was supposed to be more

20 efficient; it was supposed to recognize the time

21 sensitivity. Among other changes, it was supposed to

22 have a hearing without cross examination, unless the

23 Commission, not the Presiding Officer, but the

24 Commission decided to use additional procedures, such

25 as cross examination. And that retention to the

1 Commission is in 2.13-22-D.

2 What happens at the hearing is

3 specifically set forth in Section 2.13-22. And in

4 lieu of cross examination, that section specifically

5 directs the parties to propose questions to the

6 Presiding Officer for the Presiding Officer to ask.

7 Those questions are explicitly set forth to be filed

8 at two stages of the proceeding. One, together with

9 rebuttal testimony and a response Statement of

10 Position. Those will be questions addressed to the

11 initial written testimony. And, second, following the

12 submittal of rebuttal testimony in a separate stage

13 where one submits proposed questions to the Licensing

14 Board, and that is specifically set out in 13-22-A(ii)

15 and A.4. There are no other provisions for submitting

16 questions, and 2.13-22 starts off by saying the

17 parties -- participants may submit the following.

18 So we're talking about submittals. And

19 it's clear that those two opportunities that are set

20 forth in 13-22-A are the maximum, because 13-22-A

21 starts off by saying, "Unless otherwise limited by

22 this Subpart or by the Commission." In other words,

23 the Commission could cut back those requirements if it

24 chose to do so. But there's no indication in there

25 that those are to be enhanced, that there is to be

1 more than what's set forth in 13-22-A.

2 Now, 13-22-B talks about the oral hearing,

3 and it says at the oral hearing ordinarily questioning

4 will be conducted by the Presiding Officer using

5 either the Presiding Officer's questions or questions

6 submitted by the participants. Now, 13-22-A tells

7 when you submit questions, in fact. As I said, 13-22-

8 A specifically says the parties may submit. There's

9 no other provision for submitting questions at the

10 time of the hearing.

11 It would be inappropriate, we think, for

12 that opportunity to be given for a variety of reasons.

13 First of all, the Commission, when it adopted Subpart

14 M in the Statement of Consideration, specifically said

15 that the -- and I'm quoting, "The proposed Subpart M

16 rule provides for parties to submit proposed questions

17 to the Presiding Officer. This will allow the parties

18 to suggest what they believe to be appropriate

19 questions for the witnesses but will allow the

20 Presiding Officer better control of the examination of

21 witnesses. This provision should effectively

22 eliminate the need for objections and interruptions

23 during witness examinations." In other words, we were

24 not to have questions posed in the midst of witness

25 examinations, which is, I think, what the Presiding

1 Officer is suggesting that we do in this case.

2 There are policy reasons why these kinds

3 of questions should not be allowed in this case. In

4 this case, specifically, CAN decided not to submit

5 written questions. Now they have the opportunity at

6 the hearing to pose, on the fly, questions for which,

7 unlike the ones that they were required to submit in

8 writing, we would not have had the opportunity to see

9 the questions in advance, to see if we had the right

10 people to answer those questions, and prepare answers.

11 It certainly prevents the parties' preparation for the

12 hearing.

13 In a Subpart M hearing, as you know, there

14 is no discovery, unlike a Subpart G hearing, where one

15 can find out in advance of the hearing what the

16 parties' questions are. Now we have a situation where

17 a party can sit back, take no steps to advise the

18 other parties as to what their concerns are, and come

19 in with a long list of questions. Now, concededly,

20 the Presiding Officer has the discretion to ask or not

21 to ask those questions. However, it puts the party

22 receiving those questions at a decided disadvantage,

23 one that was not contemplated by the Subpart M rules.

24 Similarly, there's no opportunity to

25 answer the matters raised in those questions, because

1 there is no provision in Subpart M for redirect
2 testimony. And I think if one were to suggest that
3 the solution to this problem would be to have redirect
4 testimony, again, would expand Subpart M well beyond
5 what the Commission had in mind.
6 The issues which are being raised and
7 which might be raised, we think would defeat the
8 purpose of the Subpart M rules and would do away with
9 much of the advantages which the Commission sought to
10 achieve when it adopted Subpart M. And for those
11 reasons, I would suggest that Subpart M does not
12 contemplate posing questions -- parties posing
13 questions at the time of the hearing. They were
14 supposed to be submitted in advance, in writing, and
15 I think what is being suggested now is inconsistent
16 with the clear direction of the regulations.
17 JUDGE BECHHOEFER: Yes. I might also add
18 I'm relying also on the statement in paragraph, of the
19 regulations, 2.13-20-A3.
20 MR. SILBERG: Yes. That was the provision
21 that I noted before we started.
22 JUDGE BECHHOEFER: Yes. I was relying on
23 really both of those.
24 MR. SILBERG: Well, that provision simply
25 states the overall powers of the Board. It does not

1 create new opportunities for the Board to invite
2 questions. The introductory language to 2.13-22-A,
3 which says, "Unless otherwise limited," the reference
4 to 2.13-20 would be inconsistent with that
5 introductory language, because that would otherwise
6 enhance the directions provided in 13-22. So I don't
7 believe that a reading of 13-20-A3 would indicate that
8 that provides additional authority for the Licensing
9 Board. That simply says the Licensing Board has the
10 authority to pose the questions that have been
11 submitted under 13-22.
12 JUDGE BECHHOEFER: All right. I think the
13 reference, though, to suggestions allows me, for one
14 thing, to determine their appropriateness. And I
15 think I disagree. I think that part of the oral
16 hearing -- now, I'm not going to allow new issues or
17 new subject matter, but this is questions regarding
18 testimony that's been right now admitted into
19 evidence. And the parties, I believe, should have an
20 opportunity to suggest -- and, Mr. Silberg, that
21 includes yourself. If you would like to have Mr.
22 Lochbaum to ask further questions about his testimony,
23 feel free, and I will entertain such suggestions.
24 MR. SILBERG: How much time does Mr.
25 Lochbaum have? I understood he was only available

1 till 12:30.

2 JUDGE BECHHOEFER: Is that correct?

3 MR. JUDSON: Why don't we ask Mr.

4 Lochbaum?

5 JUDGE BECHHOEFER: Mr. Lochbaum, how much

6 time do you have available?

7 MR. LOCHBAUM: I wanted to get to the

8 Regulation Information Conference at one, and it's

9 about a 15-minute walk. But I can be a few minutes

10 late if that's necessary.

11 JUDGE BECHHOEFER: You could probably read

12 the Commissioner's speech which you'll likely hear.

13 It will be put out in print somehow.

14 (Laughter.)

15 MR. LOCHBAUM: That's correct.

16 JUDGE BECHHOEFER: Mr. Judson, do you have

17 any clarifying questions? Don't go --

18 MR. JUDSON: Mr. Bechhoefer, I just wanted

19 to offer a comment on the procedural question that's

20 been brought up.

21 JUDGE BECHHOEFER: Oh, okay. Okay.

22 MR. JUDSON: Which is that, I mean, you

23 know, we've experienced this proceeding as having a

24 lot of -- I mean there's been -- because this is the

25 first time we've actually gone through a hearing stage

1 in a Subpart M hearing, that a lot of these kind of
2 questions have been unclear throughout this process,
3 in terms of what happens at what stage and what's
4 permitted to happen at other stages. And we actually
5 didn't expect that we would be able to propose
6 questions here today. We thought that we had to do it
7 -- to pre-file those.
8 JUDGE BECHHOEFER: You sound like Mr.
9 Silberg.
10 MR. JUDSON: Well, we --
11 MR. SILBERG: It was obvious from the
12 regulation.
13 MR. JUDSON: We just didn't -- but in
14 looking at Subpart M, there's Subpart -- I mean
15 there's 2.13-20, Responsibility and Power of the
16 Presiding Officer in an Oral Hearing, Subsection A3,
17 says that "The Presiding Officer has the power to
18 question participants and witnesses and entertain
19 suggestions as to questions which may be asked to
20 participants and witnesses."
21 JUDGE BECHHOEFER: Well, that's what I was
22 doing.
23 MR. JUDSON: And it appears that in fact
24 you do have the power to permit it yourself. I don't
25 know that we would have been able to come into this

1 room expecting that we would be able to do it, but
2 that you appear to have the power to open it up.
3 JUDGE BECHHOEFER: Mr. Silberg, do you
4 think you have some questions that you would like to
5 suggest?
6 MR. SILBERG: Just a minute, please. I
7 have a few questions at least on the spur that I would
8 propose. Do you want to take them one at a time?
9 JUDGE BECHHOEFER: I'd prefer, yes.
10 MR. SILBERG: Okay. I would ask Mr.
11 Lochbaum whether the statement in paragraph 9A of his
12 testimony that said there were more units with annual
13 capacity factors under 85 percent than above 85
14 percent, when he looks at the numbers, which is 309
15 under and 307 over, whether that is essentially the
16 same as about equal number of units had capacity
17 factors over and under 85 percent?
18 JUDGE BECHHOEFER: Mr. Lochbaum, I think
19 that is a good question. Did you hear the question,
20 as proposed?
21 MR. LOCHBAUM: Yes, I did.
22 JUDGE BECHHOEFER: Presume that I'm asking
23 it.
24 MR. LOCHBAUM: Paragraph 9A says that
25 there were 309 reactor years where the annual capacity

1 factor was less than 85 percent and 307 when the
2 annual capacity factor was above 85 percent -- 85 or
3 above. So it is approximately equal, with two more
4 years being less than above. But I think that ties
5 back to paragraph 9I where it says that 48 units had
6 an average annual capacity factor over this six-year
7 period below 85 percent. Not stated but implied is
8 the fact that there are 103 total units in the
9 database, so the remainder of the units had average
10 annual capacity factors above 85 percent, which is
11 another way of basically stating what's in paragraph
12 9A.
13 MR. SILBERG: If I could ask a follow-up
14 question, Judge Bechhoefer?
15 JUDGE BECHHOEFER: I've already got one,
16 but let's hear yours.
17 MR. SILBERG: Okay. That means that there
18 are more units that had average annual capacity
19 factors above 85 percent than there were that had
20 annual average capacity factors below 85 percent; is
21 that correct?
22 JUDGE BECHHOEFER: Mr. Lochbaum, did you
23 hear that?
24 MR. LOCHBAUM: Yes, I did. Yes, paragraph
25 9I implies that there were units that had average

1 annual capacity factors above 85 percent than had them
2 below. But paragraphs 9B and paragraphs 9F point out
3 that neither of the IP-3 or JAF units were able to
4 fall into that category, averaging above 85 percent
5 capacity factors.
6 JUDGE BECHHOEFER: Well, one further
7 follow-up. Are you saying almost, though, that in
8 your paragraph A, which is just more or less a
9 summary, do you view that difference, that in itself,
10 that difference as having any significance? The fact
11 that it's 309 and 307, is the difference there
12 significant? The two difference, are we supposed to
13 --
14 MR. LOCHBAUM: No. No, I don't -- it's
15 not significant in my mind. Had it been the other
16 way, the 307 under and 309 above, it still would have
17 led to my conclusion that it was uncertain that either
18 of the two units, IP-3 and JAF, could maintain an
19 average capacity factor above 85 percent. In order
20 for there to be certainty, you'd have to have a large
21 number either well below 85 or above 85, and we don't
22 have that, at least over the years 1994 to 1999.
23 Given that data and that uncertainty, that led to my
24 conclusion that it's uncertain that these two units
25 could operate at or above 85 percent.

1 MR. SILBERG: Judge Bechhoefer, I would
2 also pose the question about whether Mr. Lochbaum has
3 any indication as to where the capacity factors were
4 in the year 2000 and whether that would change his
5 conclusions? Where they in general, on an industry
6 average, higher than 1994 to 1999 or lower than the
7 period that he's looking at?
8 JUDGE BECHHOEFER: Mr. Lochbaum, are you
9 aware of capacity factors for the year 2000?
10 MR. LOCHBAUM: The Nuclear Regulatory
11 Commission, to my knowledge, hasn't released that
12 data, and I don't know what the numbers would be, and
13 I'd hate to speculate.
14 JUDGE BECHHOEFER: Well, but if the
15 numbers turn out one way or the other, would you have
16 us -- or have me and the Commission after take them
17 into account as really an update of information in the
18 record?
19 MR. LOCHBAUM: Well, I guess way to answer
20 that question would be look at paragraph 9C and
21 paragraph 9E. If IP-3, Indian Point 3, and
22 Fitzpatrick were able to achieve above 85 percent
23 capacity factors last year and we drop off the low
24 years in 1994, then IP-3 would have as many annual
25 capacity factors above 85 as they did below 85, and

1 the same for Fitzpatrick. It would still be a 50/50
2 wash, and it would lead to some uncertainty or it
3 would still be uncertain that these two units could
4 achieve above 85 percent capacity factor. That would
5 just move it from a four to two split to a three to
6 three split for these two reactors, if indeed that's
7 the case. I don't know what the actual numbers were
8 for these two units last year.
9 MR. SILBERG: If I could ask another
10 question. If paragraph 10 of Mr. Lochbaum's
11 testimony, he talks about there might be potential
12 safety issues, that failure to achieve assumed
13 performance levels might impair, that necessary
14 maintenance tasks or inspections might be deferred.
15 I'd ask him if he has any indication that those
16 mights, those uncertainties, those speculations
17 specifically apply at these two plants?
18 JUDGE BECHHOEFER: Mr. Lochbaum, did you
19 hear that?
20 MR. LOCHBAUM: Yes, I did. As I had
21 answered previously in why I included paragraph 10 in
22 my testimony, the configuration that these two plants
23 are going towards is a lot closer resemblance to the
24 Maine Yankee model where these problems were reported.
25 The fact that it's a close model doesn't necessarily

1 mean that either plant will fall into the same trap,
2 but it definitely raises a question, and clearly the
3 potential exists, for the low cost kind of production
4 model to lead to the same environment that led the
5 problems at Maine Yankee. So it's a possibility, but
6 I definitely am not stating that it's a certainty at
7 either of these plants.
8 MR. SILBERG: And one other question. I
9 think Mr. Lochbaum said before that the configuration
10 between Maine Yankee and its owner, Central Maine, was
11 similar to a limited liability company. And I'd ask
12 him, isn't it true that Central Maine is not the only
13 owner of Maine Yankee and in fact there is no L.L.C.
14 arrangement at Maine Yankee?
15 MR. LOCHBAUM: That is correct.
16 JUDGE BECHHOEFER: Wait a minute. I'm
17 supposed to ask the questions, but I do adopt that
18 suggested question. Mr. Lochbaum?
19 MR. LOCHBAUM: That's correct. Maine
20 Yankee is not or was not a limited liability
21 corporation. That's why I was very careful to say
22 that it's similar to the model, it's not a clone, if
23 you will. But I think the control over the cash flow
24 and the limited funds available are pertinent
25 questions. They're similar, they're not the same by

1 any means, but they are similar enough that the
2 questions or the potential concerns are relevant in
3 this proceeding.
4 MR. SILBERG: I would ask a follow-up
5 question. Does he know how cash flow was controlled
6 in the Maine Yankee situation?
7 JUDGE BECHHOEFER: Mr. Lochbaum, do you?
8 MR. LOCHBAUM: Judge, as I indicated in
9 the testimony, the NRC's inquire into that, the cash
10 flow, was terminated when the Plant's owner decided to
11 permanently close the Plant. In some of the open
12 Commission briefings that preceded that Plant owner's
13 decision, then NRC Chairman Shirley Jackson asked
14 questions of Maine Yankee's CEO, David Flanagan, about
15 that, and there was some exploration that it wasn't
16 fully explored at the time that the Plant was
17 permanently closed.
18 MR. SILBERG: So I take it --
19 MR. LOCHBAUM: I have some insights, but
20 I don't have a complete and full understanding, and I
21 don't think the NRC does at this point.
22 MR. SILBERG: So I would ask him, then, he
23 can't really compare Maine Yankee, which he says he
24 doesn't fully understand, with Entergy, which I don't
25 know whether or not he fully understands. But if he

1 doesn't understand Maine Yankee, he certainly can't
2 compare it to something else, which he either does or
3 doesn't understand.
4 JUDGE BECHHOEFER: Yes. Mr. Lochbaum, can
5 you explain, given your lack of full understanding of
6 Maine Yankee, can you validly compare it to the
7 Entergy reactors which we're considering here?
8 MR. LOCHBAUM: I believe so, because I go
9 back -- I point back to paragraph 10 of my testimony,
10 where the Maine Yankee Independent Assessment Team
11 report said, quote, "Management is effectively
12 operating the Plant within budget constraints
13 established by the owners. However, the limitations
14 on resources have delayed and deferred Plant upgrade
15 improvements and lower priority corrective actions
16 which did not meet the threshold for safety regulatory
17 compliance or reliable production," end quote.
18 The proposed arrangement for Indian Point
19 3 and Fitzpatrick have budget constraints and
20 limitations and are based on projections of revenue
21 income from the 85 percent capacity factor assumptions
22 that might lead to the very same -- or very similar,
23 not the very same, very similar configurations that
24 led to the conditions referred on by the NRC in its
25 ISAT report. Therefore, I think I have a thorough

1 enough understanding of what happened at Maine Yankee
2 and what is being proposed at Fitzpatrick and Indian
3 Point 3 to draw the parallels between the two plants
4 and the one's history and the one's future.
5 MR. SILBERG: And I would ask Mr. Lochbaum
6 whether he has studied the budget constraints and
7 limitations that allegedly apply to Indian Point 3 and
8 Fitzpatrick Plants?
9 JUDGE BECHHOEFER: Mr. Lochbaum, have you
10 --
11 MR. LOCHBAUM: I have not studied the
12 proprietary documents where much of that information
13 is maintained. I have reviewed the redacted or the
14 non-proprietary versions of the arrangements, and I
15 used that as the basis for my understanding of what's
16 being proposed at those two plants.
17 MR. SILBERG: But it is true that the
18 dollar numbers, the projections on operating costs,
19 O&M costs, were not available for you to review; isn't
20 that correct?
21 JUDGE BECHHOEFER: Is that correct, that
22 you did not review O&M costs?
23 MR. LOCHBAUM: That is correct.
24 MR. SILBERG: I don't have any further
25 questions to propose.

1 JUDGE BECHHOEFER: Mr. Lochbaum, I guess
2 that's all the questions we have, and we thank you for
3 -- oh, Mr. Judson has --
4 MR. JUDSON: Are we permitted to propose
5 some questions? We actually have a few.
6 JUDGE BECHHOEFER: I would permit you to
7 as -- I would guess -- no, no. I think you may, but
8 you may not -- it has to be based, to some extent at
9 least, on the previous questions asked your witness,
10 either by myself or at the suggestion of the
11 Licensees. It shouldn't be new topics.
12 MR. JUDSON: Well, we can propose them to
13 you, and you can decide?
14 JUDGE BECHHOEFER: Yes, yes.
15 MR. JUDSON: Okay. The first one we have
16 proposed to Mr. Lochbaum is, in your estimation or to
17 the best of your knowledge, are low average capacity
18 factors generally associated with an extended outage?
19 MR. SILBERG: I would object, because that
20 has nothing to do with any questions that I asked or
21 that Judge Bechhoefer asked.
22 JUDGE BECHHOEFER: Yes. I don't think
23 that one is -- I don't think that question is based on
24 either what Mr. Silberg proposed or what I asked.
25 MR. JUDSON: Okay. I'll just read to you

1 the ones that we have.

2 JUDGE BECHHOEFER: Pardon?

3 MR. JUDSON: I'll just read to you the

4 ones that we have, if that's --

5 JUDGE BECHHOEFER: Okay.

6 MR. JUDSON: Do operation --

7 JUDGE BECHHOEFER: Do them one at a time,

8 so that if we decide they should be answered, I'll ask

9 them.

10 MR. JUDSON: Sure. Do operation and

11 maintenance activities generally increase with the

12 length of the outage?

13 MR. SILBERG: Objection.

14 JUDGE BECHHOEFER: I don't think that's

15 relevant. No, I think that one would not be -- I

16 don't think I would adopt that suggestion either.

17 MR. JUDSON: Okay. Does the 1999

18 refueling outage at Indian Point 3 indicate improved

19 operations at the Reactor?

20 MR. SILBERG: I would object to that to

21 the extent that it goes beyond capacity factor, and

22 his numbers on capacity factor are already in the

23 testimony, so I think it would be redundant.

24 MR. JUDSON: Can I offer an explanation of

25 why we asked it?

1 JUDGE BECHHOEFER: Mr. Judson, you wish to
2 clarify?
3 MR. JUDSON: Sure. In the Entergy
4 witness' testimony, I believe it's Mr. Kansler, who in
5 trying to explain how the Entergy Companies expect to
6 improve the capacity factors at Indian Point 3 and
7 Fitzpatrick --
8 MR. SILBERG: Excuse me, I think we're
9 talking about -- and I don't know what you're going to
10 say -- but that testimony is proprietary. It has
11 nothing to do with any of the testimony, any of the
12 questions and answers that were provided here. I
13 would really object. I think we're getting afar
14 afield. I think this just reinforces the problems
15 that I have with this process.
16 JUDGE BECHHOEFER: I think that would be
17 a better question directed to the Entergy witnesses --
18 MR. JUDSON: I see. Okay.
19 JUDGE BECHHOEFER: -- which you will have
20 a chance to do or suggest.
21 MR. JUDSON: Okay. We'll ask it then.
22 Then the last question that we had is that when
23 entering a maintenance outage, it always clear how
24 long it will last?
25 MR. SILBERG: Same objection. There's no

1 testimony on maintenance outages, no questions on
2 maintenance outages.
3 JUDGE BECHHOEFER: I might say, I still
4 have some questions for your witnesses about how
5 either fuel loading or maintenance outages are taken
6 into account.
7 MR. SILBERG: Certainly.
8 JUDGE BECHHOEFER: But that's for your
9 witnesses.
10 MR. SILBERG: Yes. And our witnesses will
11 be happy to answer those.
12 JUDGE BECHHOEFER: Right. Those are the
13 questions I still have for your witnesses. I think we
14 will not entertain the suggested question right now.
15 MR. JUDSON: That was our last proposed
16 question. We don't have any more.
17 JUDGE BECHHOEFER: Okay. I guess that's
18 all the questions we have. Mr. Lochbaum, we
19 appreciate your testimony, your being here by phone at
20 least.
21 MR. LOCHBAUM: Well, I appreciate your
22 arranging for me to participate this way. I
23 appreciate that.
24 JUDGE BECHHOEFER: Well, I'm glad we could
25 accommodate that. I could start asking you questions

1 about the Millstone case, but I won't, not in this
2 context.
3 (Laughter.)
4 MR. LOCHBAUM: Thank you.
5 JUDGE BECHHOEFER: Good bye, and we
6 appreciate your appearance.
7 MR. LOCHBAUM: Thank you. Bye.
8 JUDGE BECHHOEFER: I think at this stage
9 we should adjourn for lunch and come back.
10 MR. SILBERG: We just talked about
11 schedules too. At some point, the next thing would be
12 to have a discussion on Issue 2, and our witnesses
13 should remain available? Is that your --
14 JUDGE BECHHOEFER: That would be my
15 contemplation, unless there's some -- well, we could
16 --
17 MR. SILBERG: We'd like to finish up with
18 Issue 2 so those witnesses can go off and go home.
19 JUDGE BECHHOEFER: Right. But is it
20 necessary that they go off before lunch?
21 MR. SILBERG: No.
22 JUDGE BECHHOEFER: Okay. Because we do
23 have a few more, and most of them are general
24 questions. They may be just addressed to you as much
25 as to, well, the various parties, rather than just

1 your witnesses. But I think the witnesses should be
2 here.
3 MR. SILBERG: Okay. One ministerial
4 question. Is this room -- we can go off the record at
5 this point.
6 JUDGE BECHHOEFER: Yes. We're off the
7 record.
8 (Whereupon, the foregoing matter went off
9 the record at 12:49 p.m. and went back on
10 the record at 2:02 p.m.)
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1 A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

2 (2:02 p.m.)

3 JUDGE BECHHOEFER: Okay. Back on the

4 record. I guess we're returning to Contention 2.

5 Now, one of the questions -- this is not for a

6 specific witness -- but the Commission, in its CLI-

7 0022, specifically brought to CAN's attention, and

8 other parties' attention, that there were

9 modifications to the decommissioning trust agreement,

10 modifications which appear to address some of CAN's

11 concerns, in any event.

12 CAN's Statement of Position appears not to

13 address how these modifications fail to address CAN's

14 concerns. And my question is how did the

15 modifications fail, or do they fail?

16 MR. JUDSON: Well, Your Honor, this is

17 what we were trying to explain before in the previous

18 discussion this morning, which is that we feel that

19 even though the staff has tried to anticipate a number

20 of the problems that could occur under this

21 arrangement, in terms of whether NYPA would attempt to

22 limit the Entergy Companies' decommissioning

23 activities and how much they needed to be reimbursed

24 from from the fund. We see a lot of anticipations in

25 what the staff proposes of the potential things that

1 could go wrong in this circumstance.

2 What we believe is that the imposition of

3 conditions still puts the NRC in a vulnerable position

4 in terms of being able to enforce its regulations,

5 because it puts the NRC in a position of having to

6 react to things that NYPA does rather than have a

7 consistent regulatory authority over the holder of the

8 decommissioning fund. And the Entergy Companies have

9 not proffered any arguments as to why the NRC should

10 consider granting this anomalous arrangement that

11 they've proposed for handling decommissioning funds.

12 And so there's no justification for

13 approving the staff's conditions on NYPA's ownership

14 of the fund as opposed to requiring that actually the

15 Entergy Companies have their own decommissioning trust

16 fund as a prepayment of the costs that the NRC

17 requires under 50-75.

18 JUDGE BECHHOEFER: Now, on what do you

19 base your assumption, I guess, that either PASNY or

20 the Entergy Companies or NYPA, however we want to call

21 the entities, are seeking an IRS rule on the tax

22 status of the decommissioning fund?

23 MR. JUDSON: Well, perhaps it's a semantic

24 distinction that's being anticipated there. What the

25 application said, in terms of this issue -- and they

1 say this on page 2 as well as, I believe, it's page 11
2 -- what they refer to is the authority may elect to
3 transfer its interest in the trust fund to Entergy
4 Nuclear Fitzpatrick or Indian Point 3, in the case of
5 each application, at the end of license upon
6 dismantlement of the unit or if the fund becomes
7 taxable.
8 And we believe that there's an
9 anticipation that the tax status of the
10 decommissioning fund -- so long as NYPA is holding it
11 for a reactor which they don't own anymore and have no
12 interest in, there seems to be a question about
13 whether the fund will become taxable under the IRS'
14 rules at a certain point, especially since NYPA -- and
15 the staff actually addresses this in their safety
16 evaluation report saying that, "Based on our review of
17 the provisions in their entirety, the staff concludes
18 that the effect of the decommissioning arrangements is
19 to limit the authorities' -- PASNY's responsibilities
20 to holding and dispersing a decommissioning trust fund
21 with the apparent purpose of attempting to limit any
22 adverse federal income tax consequences to the
23 decommissioning funds."
24 So what's been promulgated, in terms of
25 both the application, what would happen in terms of

1 NYPA handing the fund back over to Entergy, and in
2 terms of the staff explaining why they've proposed
3 this circumstance, is because the tax status of the
4 decommissioning fund is uncertain. And, in fact, that
5 that's the only reason that the staff contemplated for
6 why they were being asked to accept this anomalous
7 arrangement.
8 And, in fact, in the Entergy Companies'
9 testimony, I believe in Mr. Collins' testimony, he
10 discusses the arrangements under which NYPA retains
11 possession of the funds, and he refers specifically to
12 these specified events on page 2 and page 11 of the
13 applications, which have -- and one of which is
14 clearly the tax status of the decommissioning fund.
15 JUDGE BECHHOEFER: Well, let me then ask
16 the Licensees. I'm not going to get into details
17 about tax status. But to the extent the tax status is
18 mentioned, to what extent does this transaction depend
19 on future tax rulings, future IRS rulings?
20 MR. SILBERG: Not at all.
21 JUDGE BECHHOEFER: Not at all?
22 MR. SILBERG: Your question to CAN asked
23 what was the basis for saying that we were seeking a
24 tax ruling, and they didn't answer your question.
25 There is no basis. We said there is no basis. They

1 said we haven't proffered any arguments justifying
2 leaving the funds with NYPA. That justification is
3 throughout the application, throughout our testimony.
4 The justification is quite simple: By
5 leaving the funds in the hands of New York Power
6 Authority, the funds continue to generate income tax-
7 free. That's a justification. It's a very good
8 justification. It's a sound economic justification.
9 Anything more, I don't know what one can say, but the
10 justification is there, and it's simple and
11 straightforward. There is no need for further IRS
12 rulings. We haven't asked for any; we don't intend to
13 ask for any.
14 But by leaving the fund with the
15 Authority, income continues to accumulate tax-free, as
16 opposed to paying the tax that's required under
17 Section 468A of the Internal Revenue Code for
18 qualified funds, 20 percent rate. So we are saving
19 money to decommission the Plant. We are letting the
20 fund build up faster. There will be more money
21 available to decommission the Plant. Simple,
22 straightforward justification.
23 JUDGE BECHHOEFER: And it's your
24 anticipation that nothing in the transaction itself
25 that we're considering would remove the tax-free

1 status.

2 MR. SILBERG: Correct. The transaction is

3 complete.

4 JUDGE BECHHOEFER: And the funds still

5 remain --

6 MR. SILBERG: And the funds remain with

7 NYPA.

8 JUDGE BECHHOEFER: Yes.

9 MR. SILBERG: No change in tax status.

10 JUDGE BECHHOEFER: Would you like to

11 respond?

12 MR. JUDSON: Well, I think there's a lack

13 of -- there's a certain unclarity and confusion in

14 what Mr. Silberg just answered, which is that

15 throughout the Applicant's arguments and throughout

16 their witnesses' testimony, they clarified that NYPA's

17 responsibility for making payments for decommissioning

18 is limited to the NRC inflation-adjusted cost of

19 decommissioning, which is approved under the

20 regulations.

21 And, in fact, that the fund, as

22 constituted currently, is worth more than what the NRC

23 would require under those regulations. And so it's

24 not clear that there's any advantage to the rate that

25 Mr. Silberg just quoted in terms of the fund growing

1 to more money, because in fact the fund seems to
2 already satisfy the NRC's requirements.
3 JUDGE BECHHOEFER: Well, but that's --
4 isn't it accurate that the fund will be growing just
5 through the passage of time and receiving payments and
6 interest, and that therefore the fact that it may be
7 tax-free might be of some value?
8 MR. JUDSON: Well, what the Applicant's
9 also clarify in their testimony is -- this is in terms
10 of Mr. Henderson's testimony -- is that there will be
11 -- that if the fund is declared taxable, that those
12 funds still cannot be withdrawn from the
13 decommissioning fund itself.
14 JUDGE BECHHOEFER: Why does that follow?
15 I'm a little confused.
16 MR. JUDSON: There doesn't seem to be any
17 advantage, in terms of the NRC's requirement, to the
18 facts that Mr. Silberg is proposing.
19 MR. SILBERG: Mr. Bechhoefer, if I might
20 answer. I think Mr. Judson has misunderstood the
21 testimony.
22 JUDGE BECHHOEFER: I'm just trying to see
23 what the issue is here, if any.
24 MR. SILBERG: If the fund were taxable, as
25 with any other decommissioning trust fund by a tax-

1 paying entity -- and there are some that are non-tax-
2 paying, some that are tax-paying -- if the fund earns
3 money and it's held by a tax-paying entity, the taxes
4 on the earnings are paid from the fund to the federal
5 government.
6 What you are talking about in your
7 testimony was the tax on the transfer of the fund from
8 the Authority to the Entergy Companies, not on the
9 earnings of the fund. The earnings of the fund would
10 be taxable if it were held by Entergy, and the fund
11 would pay those taxes. And that is recognized in --
12 every decommissioning fund in the country that is held
13 by a tax-paying entity pays money to the federal
14 government. I think your witnesses will agree with
15 that.
16 MR. JUDSON: Am I allowed to ask a
17 question in response to that?
18 MR. SILBERG: One other point.
19 JUDGE BECHHOEFER: Well, wait till he's
20 through.
21 R. SILBERG: The other thing is, CAN is
22 saying that there doesn't seem to be any justification
23 since there's already enough money in the fund to
24 decommission to meet the NRC's minimum. I don't think
25 I understand CAN to say, "We want to put less money

1 away. We're not worried. We should get rid of some
2 of that money, because maybe we have too much."
3 That's never been my understanding of CAN's position,
4 although that seems to be what they're saying now.
5 It's certainly not our position.
6 So the fact that we may already meet the
7 NRC minimums, I think has nothing to do with whether
8 there is a benefit that the money should continue to
9 accumulate in the fund, unless CAN wants to take the
10 position that we have too much money in the
11 decommissioning fund and we ought to get rid of some
12 of it. I don't think that's their position.
13 JUDGE BECHHOEFER: Did you want to follow
14 up on something?
15 MR. JUDSON: Well, we can clarify our
16 position in so far as Mr. Silberg seems to be unclear
17 about it himself, which is that we're not concerned
18 about there being too much money in the fund. It's
19 that under the arrangement the Applicants have
20 proposed, if the fund turns out to be worth more than
21 the NRC requires, as there's every indication it will
22 be at this point, that that money will not necessarily
23 be used for decommissioning, because NYPA's liability
24 to pay for decommissioning activities is limited to
25 the amount the NRC requires. And if the fund is worth

1 more than that, then NYPA isn't obligated to make any
2 payments beyond what the NRC requires.
3 JUDGE BECHHOEFER: Okay. Mr. Judson, do
4 you disagree with anything in the recent staff read
5 which was filed concerning NRC authority?
6 MR. JUDSON: Well, what we find that's
7 missing from both the applicant's and the staff's
8 arguments at this point is that in the Commission's
9 order -- memorandum and order, in terms of the issue
10 that they admitted as Issue Number 2, they explicitly
11 asked parties to address whether the Commission will
12 continue to retain authority over NYPA for completing
13 remediation responsibilities that it retains under
14 this sale. And whether under that circumstance NYPA
15 would have access to decommissioning funds or access
16 to funds to pay for their remediation
17 responsibilities.
18 And although the Commission explicitly and
19 I believe -- in footnote 25 on page 26, it says, "CAN
20 raises related issues, whether NRC approval of the
21 transfer will deprive the Commission of authority to
22 require PASNY to conduct remediation under
23 decommissioning, and whether under those circumstances
24 PASNY would no longer have access to the
25 decommissioning trust fund for the remediation it

1 would need to complete." These issues relate to the
2 admitted issue involving 10 CFR 50-75 Supra, and CAN
3 may address them at the hearing in that context.
4 And what the staff's briefs and the
5 Applicant's briefs have addressed is the question of
6 NYPA's fiduciary responsibilities for paying Entergy
7 for decommissioning expenses with these reactors, but
8 they have not addressed at all the ability of the NRC
9 to continue to have regulatory authority over NYPA for
10 remediation responsibilities that it retains. And in
11 fact, in the Purchase and Sale Agreement to the
12 applications, it's stated clearly, "Under liabilities
13 not assumed by the Entergy Companies, any liabilities,
14 including, without limitation, any environmental
15 liabilities relating to the off-site disposal,
16 storage, transportation, discharge, release, recycling
17 or the arrangement for such activities by the seller,
18 that is NYPA, of hazardous substances that were
19 generated at a site, at any off-site hazardous
20 substance facility or at another location that is not
21 a site, other than as a result of subservice migration
22 from a site where the initial disposal, storage,
23 transportation, discharge, release or recycling of
24 such hazardous substance is at such off-site hazardous
25 substance facility occurred prior to the closing, that

1 is under NYPA's responsibility."

2 And we believe that this -- this is the

3 issue that we raised in terms of our initial hearing

4 request and that the Commission asked us to address in

5 this proceeding. And neither the staff nor the

6 Applicants have addressed that circumstance of how the

7 NRC maintains regulatory authority to ensure that NYPA

8 completes remediation responsibilities or in fact even

9 assesses remediation responsibilities that perhaps may

10 be within the NRC's jurisdiction to control. And we

11 believe that therein lies a major deficiency in both

12 the staff's arguments and briefs and the Applicant's

13 briefs, is that they refuse to acknowledge that the

14 Commission asked us to address this argument, and they

15 don't make any convincing arguments in relation to it.

16 MR. SILBERG: If I could respond to that.

17 The answer is quite clear, and it's in the

18 Commission's regulations. Decommissioning is defined

19 in the Commission's regulations at 10 CFR 50.2 as the

20 means to remove a facility or site safely from service

21 and to reduce residual radioactivity to a level that

22 permits release of the property for unrestricted use

23 or use of the property under restricted conditions and

24 termination of the license.

25 What Mr. Judson is talking about is off-

1 site disposal, which is outside the scope of
2 decommissioning. It is outside the scope of the
3 decommissioning trust fund. It is outside the scope
4 of this hearing. NYPA does retain responsibilities.
5 Every other utility retains responsibilities to the
6 extent that they may have sent materials to off-site
7 disposal facilities. But that is not part of
8 decommissioning as defined in 10 CFR Part 50.
9 With respect to the retained liabilities
10 that we addressed before, they're specifically
11 addressed in the Purchase and Sale Agreement in
12 Schedule 5.13. As I talked about before, those are
13 non-radiological responsibilities, and therefore,
14 again, outside the scope of NRC's decommissioning
15 responsibilities.
16 JUDGE BECHHOEFER: Did you have --
17 MS. KATZ: What we understand, in fact,
18 the Commission to be raising is what we feel is a very
19 serious issue in this, which is about the potential
20 for loss of radiological control by former licensees
21 in which you have this anomalous situation. In fact,
22 the Commission refers to it as remediation and
23 underdecommissioning. And there really is a question
24 that has in fact surfaced repeatedly during
25 decommissioning under license termination plans where

1 there has been, in fact, off-site contamination found.
2 And, in fact, one of the things we raised and
3 submitted was evidence of NYPA in fact shipping
4 contaminated waste to a landfill. One hundred sixty-
5 five shipments, 90 percent of which were radioactive.
6 The radionucleoids included cobalt 60 and cesium 137,
7 which has a half-life of 30 years. And although NYPA
8 denied that it had made these shipments, it finally
9 acknowledged it did. And during the time these
10 shipments occurred, there were fuel failures at
11 Fitzpatrick. And one of the things that we've seen at
12 Haddum Neck and at Yankee Atomic is that at the time
13 of fuel failures there is also the release of hard pot
14 particles and hard to detect nucleoids.
15 And so one of the concerns in this is who
16 is going to be responsible for what may become
17 orphaned waste? And we believe that this is important
18 for the Commission to address at this point in terms
19 of setting a clear understanding of accountable, that
20 if Entergy is not going to be responsible for off-site
21 contamination, is the Commission going to be able to
22 hold NYPA accountable for this off-site contamination?
23 And is the Commission going to set a fund then for
24 NYPA to hold onto to in fact have the monies to do a
25 cleanup? And how will the cleanup be addressed?

1 I mean our concern is that this is a
2 slippery slope, because besides the fact whether it's
3 NYPA in this case, the precedent-setting nature of it
4 is that this is the beginning of a series of license
5 transfers in which there are going to be new companies
6 holding licenses on sites where there has been
7 contamination and potentially off-site contamination.
8 We are looking at the tip of an iceberg in this
9 situation of a lot of ways that there was a commitment
10 made to clean up in communities.
11 And in a certain way, to us, this is one
12 of the major issues in this situation, is the loss of
13 radiological control in communities and who will clean
14 that up. And what the staff doesn't address and what
15 NYPA doesn't address is how -- or Entergy addresses --
16 is what safeguards will be put in check, not just to
17 provide financial security but a commitment to the
18 community that this waste will be accounted, and in
19 fact it will have the money to be cleaned up. And
20 that's the issue we're raising.
21 JUDGE BECHHOEFER: Are those commitments
22 appropriate to consider in this type of a transfer
23 proceeding or should it be left to any proceeding
24 governing, for instance, an LTP?
25 MS. KATZ: I think this is the one moment

1 in history that it has to be addressed. Because what
2 Entergy is also asking for is to create an anomalous
3 situation in terms of holding onto the decommissioning
4 fund, in which NYPA will hold onto the fund and
5 Entergy will access it. And what it raises is this
6 opportunity for the Commission to address this issue.
7 By the time of the License Termination Plan, there is
8 the potential for former licensees to not even exist
9 anymore.
10 And if this isn't clarified, in terms of
11 what is going to happen to the waste and who is going
12 to be accountable to it, and that's the NRC's mandate,
13 in terms of providing health and safety, and also
14 confidence that the people can have that the NRC is
15 going to do its job, in terms of being able to have
16 authority over present and, in this case, potentially
17 former licensees.
18 It creates a really difficult and troubled
19 situation. And I don't know where else it can be
20 addressed, because by the time of License Termination
21 Plans, a lot of times there isn't even historical
22 records that exist. I mean we're seeing that in the
23 Haddam Neck case; we saw it in the Yankee Row case in
24 which there aren't records. There were hot particles
25 that left the site repeatedly. There was contaminated

1 soil that wound up at a day care center in
2 Connecticut.
3 I mean these are issues that need to be
4 addressed, and I actually don't -- we don't know where
5 else it can be addressed if we don't attempt to gain
6 some control over it here. And that's why we asked
7 this to be addressed, to look at this. If you've got
8 a better suggestion about where we can bring it, we'll
9 try. It's not even directly involved with Entergy and
10 NYPA, but it's about an issue of accountability that
11 were made to communities about cleanup.
12 MR. SILBERG: Judge Bechhoefer, I agree
13 that it's not directly involved with Entergy or NYPA.
14 It's not involved with them indirectly, I believe,
15 either. But to the extent that CAN has a concern with
16 this, they've raised what they say is a generic
17 concern. They've cited to Yankee, they've cited to
18 Connecticut Yankee. This is a generic problem. Let
19 them raise it in a generic forum. File a petition for
20 rulemaking. File a 2206 petition. This is clearly
21 not a license renewal issue.
22 Aside from the fact that the factual
23 underpinning for this issue is, I think,
24 inappropriate, as we pointed out in our initial brief,
25 even the documents that they cited did not allege that

1 there was any violation of any NRC regulatory
2 limitation on discharges of radioactive material.
3 With respect to orphaned waste, we know of
4 none in this case. Perhaps somewhere down the road
5 there may be one from some other plant. The Superfund
6 law exists for that purpose. But this is clearly not
7 a license transfer issue. The issue would be the same
8 whether or not NYPA retained the decommissioning fund
9 or whether it transferred the decommissioning trust
10 fund. In fact, with NYPA holding the decommissioning
11 trust fund, you would think there would be more
12 likelihood that if NYPA needed the money to
13 decommission and somehow didn't fall within somebody's
14 narrow view of what was appropriate, they're better
15 off having the money than not having the money.
16 With respect to no historic records, there
17 are NRC regulations currently on the books that
18 require any off-site or on-site spills to be tracked.
19 Again, this is a generic issue. It's certainly not a
20 license transfer issue.
21 JUDGE BECHHOEFER: Ms. Katz?
22 MS. KATZ: Well, I don't think the NRC
23 would like the EPA to wind up doing its business. I
24 don't think that's a good position for the Commission
25 to be in, basically abdicating its responsibility by

1 letting the EPA deal with contamination that
2 eventually winds up, because it's become orphaned by
3 the NRC. And what we're asking for is for conditions
4 to be set. If what Entergy and NYPA are willing to do
5 is put conditions in terms of holding a certain amount
6 of the fund available for site remediation, for
7 contamination that has been incurred by NYPA before
8 the license transfer, that would in fact be helpful in
9 terms of setting a kind of standard and criteria for
10 cleanup.
11 MR. SILBERG: Well, the short answer is
12 there is no such contamination for which a fund needs
13 to be set aside. If it in fact is contamination that
14 exists at the plant, that will be cleaned up as part
15 of decommissioning. If there is some off-site
16 contamination that is in violation of NRC regulatory
17 requirements, let CAN come forward and make that case,
18 file a 2006 petition. Those kinds of contamination
19 ought to be cleaned up on an ongoing basis and are
20 required to be cleaned up on an ongoing basis.
21 If you're worried about orphaned waste,
22 Maxi Flats, which is probably the best case for that,
23 is a Superfund site and is being handled accordingly.
24 This is just a non-issue and certainly not an issue
25 for license transfer.

1 MR. JUDSON: Your Honor, it needs to be
2 reiterated, I think, in regard to what Mr. Silberg is
3 saying, that the Commission asked parties to address
4 this issue, and that whether the implications of it
5 are generic or not, they wanted to know about it in
6 this case. And they didn't set it up and what they
7 didn't ask for was for us to do some sort of discovery
8 and fact finding. Well, we proved that NYPA was going
9 to have X number of decommissioning or remediation
10 responsibilities, but they wanted to know, in a legal
11 sense, whether the NRC would lose regulatory authority
12 over NYPA. Should it emerge that they have
13 remediation responsibilities, whether off-site or on-
14 site, for whatever reason.
15 What we've raised is that, in fact, that
16 the reason this is really imminent and important in
17 this situation is because there are indications that
18 there may in fact be substantial remediation
19 responsibilities that NYPA would have, and that's why
20 it's important in this case. But what the Commission
21 asked us to address was a legal question of whether
22 they would lose regulatory authority over NYPA. And
23 that's what we're -- and that's the reason for us
24 addressing it, in terms of addressing the deficiencies
25 in the applicant's and the staff's briefs.

1 JUDGE BECHHOEFER: Yes. Well, the staff's
2 recent briefs, the one they just filed, seem to say
3 that, both through inherent authority plus contractual
4 provisions, the staff retains authority, which would
5 appear, at least to me, to answer at least your
6 general question.
7 MR. JUDSON: Well, again, it's the same
8 situation, as with the holding of the fund. It's a
9 question of the fact that when the NRC has usually --
10 I mean when it's usually emerged in other
11 decommissioning cases, that there has been substantial
12 off-site contamination that's needed to be remediated.
13 That has happened through a decommissioning plan in a
14 license termination process.
15 Essentially, what's possible to have
16 happen through a license transfer is that NYPA retains
17 remediation responsibilities that normally would be
18 dealt with through a license termination process, that
19 the NRC doesn't have any way to oversee anymore. That
20 in fact, you know, should it emerge down the road,
21 that because people are becoming sick in the community
22 as a result of some waste that might have been dumped
23 somewhere, that the NRC would then become aware of it
24 and then act to enforce it. But that's really past
25 the point of harm.

1 And we believe that so long as it's
2 acknowledged that there's the possibility for there to
3 be remediation responsibilities that NYPA retains
4 following this license transfer, that the Commission
5 should in fact have a process for pursuing those. And
6 in fact we believe that under this circumstance, it's
7 not clear how the NRC would oversee such a situation
8 with the same degree of regulatory authority that they
9 have under a license termination process because of
10 the fact that NYPA would no longer be a licensee.
11 MR. SILBERG: Judge, Bechhoefer, if I
12 might just make a --
13 JUDGE BECHHOEFER: I was going to say, I
14 would like, on this point, to hear something from the
15 staff.
16 MR. SILBERG: Okay. Could I just make two
17 quick points? First, there are no indications of
18 substantial off-site remediation responsibilities.
19 That's a total red herring. There's nothing in the
20 record to support that. There's nothing in the real
21 world to support that.
22 Second, if this were any other license
23 transfer where essentially the same kinds of sharing,
24 of shifting of responsibilities occur, the seller
25 would still be retaining these kinds of

1 responsibilities and transferring others. So the fact
2 that the decommissioning funds are being retained,
3 again, is a non-issue.
4 In any commercial deal, there's always an
5 allocation of responsibilities. And the kind of
6 allocation of remediation responsibilities in this
7 transaction is not substantially different than that
8 in many other transactions that I've been involved
9 with. And so I think we're really dealing with non-
10 issues. Maybe there's a philosophical point buried
11 somewhere. I'm not sure I've seen it, but if it is,
12 it ought to be dealt with generically and not part of
13 this proceeding.
14 JUDGE BECHHOEFER: Well, I have a couple
15 of questions. I'd like to ask the staff to address
16 the latest -- the cite remediation responsibilities,
17 and would the NRC -- this is the same question you
18 answered in your brief, but you may want to elaborate
19 a little bit -- would the NRC retain sufficient
20 authority to deal with site remediation?
21 And my other question is also, has the
22 staff ever approved a transaction similar to the one
23 before us now? None of them are going to be precisely
24 the same, but has the staff ever formerly approved
25 similar arrangements?

1 MR. HOM: Let me see if I can take it --

2 JUDGE BECHHOEFER: Two different

3 questions.

4 MR. HOM: First comment is, with respect

5 to the February 26 brief we filed, that was directly

6 in response to your order --

7 JUDGE BECHHOEFER: That's correct.

8 MR. HOM: -- of February 8th, in

9 particular the issue -- and I'll quote it again; it's

10 quoted in the brief -- "Specifically, the NRC's

11 authority to control decommissioning expenditures of

12 PASNY subsequent to a divestiture of the plants." So

13 we responded to that specific question in your

14 February order and no more than that. If there's an

15 issue that goes beyond that, this brief does not

16 directly address that issue. There may be analyses in

17 the brief that would cover the issue that's coming up,

18 but quite honestly, this brief was not intended to

19 address what I hear are the issues being raised in the

20 last ten minutes.

21 There is something within the NRC's

22 jurisdiction, and I think that, at some point, the

23 staff witnesses may be better equipped to interpret

24 the regulations for you as to what the regulations

25 cover and do not cover. But from legal counsel's

1 standpoint, there's something in the NRC regulations
2 over which the NRC clearly has jurisdiction. I would
3 believe that under the analyses in this brief, or
4 otherwise, we would have authority over NYPA or PASNY,
5 whether or not they are nominally listed on the
6 license. But my understanding thus far has been that
7 the issues that are being discussed are not issues
8 that I know of or that are within the scope of the
9 NRC's jurisdiction.
10 JUDGE BECHHOEFER: Well, to the extent
11 that the site remediation activities would be part of
12 decommissioning.
13 MR. HOM: If it's a site remediation and
14 it comes within the scope of 50.75 --
15 JUDGE BECHHOEFER: Yes.
16 MR. HOM: -- and NYPA is somehow
17 regulatorally responsible for that, which I do not
18 believe is the case here. The license transfer was
19 based on the Entergy LLCs becoming the licensees and
20 becoming fully responsible for decommissioning
21 activities of the site as a licensee. And if we're
22 talking about something off-site or something that
23 does not come within the scope of our decommissioning
24 regulations, then --
25 JUDGE BECHHOEFER: I'm assuming right now

1 it does come within the scope of the decommissioning
2 regulation.
3 MR. SILBERG: I'm sorry. What is it that
4 --
5 JUDGE BECHHOEFER: I'm assuming for the
6 moment that whatever the off-site expenditures being
7 talked about are would come in within the scope of the
8 Commission's decommissioning or LTP regulations,
9 something that the Commission would have under its
10 authority.
11 MR. HOM: Your Honor, I'm just not sure
12 it's beneficial, because I don't know if I understand
13 the specific hypothetical that we're talking about,
14 and I'm not sure if it's beneficial or wise for me to
15 respond, not knowing exactly what scenario we might be
16 talking about. If something that's not what the facts
17 show in this case, and that is something that NYPA's
18 retaining responsibility for an NRC matter coming
19 clearly within our regulations, I didn't know that to
20 be the case in this license transfer. And if that --
21 maybe for a point of clarification, is that the
22 hypothetical we're talking about?
23 JUDGE BECHHOEFER: It may be, but what I
24 was assuming is that whatever the site remediation
25 expenses being talked about would be encompassed by

1 NRC regulations.

2 MR. HOM: Well, the expenses in the trust

3 fund that we were discussing in this brief, my

4 understanding was that those expenses were expenses

5 relevant to decommissioning within our regulations,

6 within the scope of our regulations. And therefore

7 our control over NYPA, with respect to those funds,

8 we've set forth in this brief.

9 MR. SILBERG: Judge Bechhoefer, if I

10 might. It was just pointed out to me that the

11 Commission's decision, CLI-0022, page 35, says that

12 the funds -- the decommissioning trust funds are set

13 aside in a trust specifically and exclusively

14 dedicated to the purpose of decommissioning the plant

15 sites. The trust cannot be used for off-site

16 remediation. The Commission has spoken on this. They

17 really, I think, are into a generic issue. It may be

18 that CAN doesn't like the generic resolution, but

19 that's the law.

20 JUDGE BECHHOEFER: Well, if what they

21 define as off-site remediation -- it may not be within

22 the scope of this proceeding or this transfer but

23 would -- if the Commission should, at some point,

24 divine that there should be some off-site remediation,

25 perhaps as defined as on-site remediation if glued,

1 for instance, to a stream flowing directly from the
2 site. I don't know whether any such exist, but would
3 Entergy then assume the responsibilities for such
4 remediation, assuming the Commission found it
5 appropriate?
6 MR. SILBERG: If you assume that the
7 Commission assumes jurisdiction, then I guess you
8 assume the Commission assumes jurisdiction.
9 JUDGE BECHHOEFER: Yes.
10 MR. SILBERG: If you assume that there are
11 facts that shows there's off-site contamination that
12 needs to be remediated and the Commission assumes
13 jurisdiction, I guess we've assumed away the question.
14 JUDGE BECHHOEFER: But does Entergy
15 inherit that responsibility?
16 MR. SILBERG: I'm sorry?
17 JUDGE BECHHOEFER: Would Entergy then be
18 responsible for, out of whatever funds it has, to --
19 MR. SILBERG: If the Commission says it's
20 within their jurisdiction relating to the plant,
21 Entergy is the licensee.
22 JUDGE BECHHOEFER: Okay.
23 MR. SILBERG: Frankly, I think that this
24 is somewhat equivalent to the "if pigs had wings"
25 problem. I mean we can speculate a lot, but I don't

1 think there are any pigs with wings that are flying.
2 I think we're talking about hypothetical situations
3 that really don't belong in the license transfer case.
4 Mr. Judson, doesn't the ruling in CLI-0022
5 on Environmental Impact Statements preclude your
6 suggestion that the NRC issue an EIS in connection
7 with these license transfers?
8 MR. JUDSON: We realize that the
9 Commission has made a generic determination for
10 Subpart M proceedings and license transfers. But they
11 didn't perceive any necessity for Environmental Impact
12 Statements or NYPA investigations under Subpart M.
13 But what we believe is that there is -- that this is
14 a special circumstance where there is acknowledged and
15 documented deliberate release of radiological
16 materials off-site, which perhaps the -- Mr. Silberg
17 is engaging in semantics again. We haven't alleged
18 that those levels are illegal. We're saying that it
19 needs to be assessed whether there's a need for
20 remediation.
21 And we believe that because of the
22 circumstances of this transaction and because of the
23 known concerns that may exist, that the only way for
24 the NRC to effectively regulate in this situation, as
25 far as we understand it -- if there is a better

1 suggestion that would clarify this ambiguity, which is
2 what the Commission is asking us to do in footnote 25
3 -- is for there to be a NYPA investigation to
4 determine what NYPA's responsibilities may in fact be
5 and to enable the NRC to continue to regulate the
6 control of radiological materials, which is its
7 mandate.
8 JUDGE BECHHOEFER: Well, are you claiming,
9 then, to reiterate, that the circumstances of the
10 transfer, which is all of the transfer, I guess,
11 that's happening, are such that it would remove these
12 facilities from the generic EIS? Are they different
13 enough that the Commission could say that these
14 facilities shouldn't be covered by the generic EIS?
15 MR. JUDSON: Your Honor, what we believe
16 -- and it may be that this hasn't come up in another
17 license transfer proceeding; maybe this is the first
18 time the Commission has had to deal with it in a
19 license transfer proceeding -- is that, because we've
20 only been involved in potentially one other where we
21 weren't granted a hearing, but that it seems to us
22 that there's a circumstance evolving under -- at least
23 it seems to exist in the circumstance of this license
24 transfer, where there is an arrangement being created
25 through the transfer of ownership of the facility,

1 where the previous owner, who may have been
2 responsible for release of radiological materials that
3 would normally be the licensee's responsibility to
4 remediate under the NRC's requirements, that now those
5 licensees are transferring the licenses to new owners
6 who, under legal terms, under their Purchase and Sale
7 Agreement, aren't accepting responsibility for the
8 harm that the previous licensee may have caused.
9 And in so far as the NRC is allowing the
10 Power Authority out of its license, transferring that
11 license to Entergy and NYPA will no longer be a
12 licensed entity by the NRC, that that is something
13 that needs to be addressed, at least in this
14 circumstance.
15 And it may be a generic issue, we're not
16 sure. We haven't actually been involved in very many
17 -- we haven't been involved in any proceedings on this
18 matter. But, in fact, in this case, it's certainly an
19 issue, and it's one the Commission asked us to
20 address.
21 MS. KATZ: And it asked us to address it
22 in terms of the loss of NRC authority, the ability to
23 deal and regulate site remediation and the monies
24 available for site remediation by someone who's no
25 longer a license holder.

1 MR. JUDSON: In fact, in terms of the
2 issue of accessing monies, what the Commission
3 clarified later in CLI-0022, I believe it's on page 35
4 where the Applicants referred to just now, they
5 clarified that there have been cases where licensees
6 have use decommissioning funds for remediation
7 activities even though they aren't strictly approved
8 as decommissioning activities under their license or
9 under the NRC regulations. But in fact licensees have
10 set up a separate part of their decommissioning trust
11 fund above and beyond what the NRC requires under
12 50.75 to ensure that there are sufficient funds for
13 remediation responsibilities, such as unrestricted
14 site release, which we believe --
15 MS. KATZ: Is a condition.
16 MR. JUDSON: Right. And that the
17 licensees have been able to set up those funds for the
18 purpose of remediation under their decommissioning
19 trust fund because they're licensed by the NRC as
20 engaging in decommissioning activities. And in so far
21 as NYPA is not going to be a licensed entity under the
22 NRC anymore, it may not have the ability to set up a
23 trust fund to fund its remediation responsibilities.
24 So the ability of NYPA to plan financially for
25 remediation could be compromised unless the NRC

1 retains some regulatory authority to ensure that they
2 complete remediation that they may have to do.
3 JUDGE BECHHOEFER: Well, couldn't the NRC
4 proceed against Entergy then if these expenditures
5 become required?
6 MR. JUDSON: They could, as easily as they
7 could -- well, I'm not sure if it's more easier or not
8 in terms of NYPA -- maybe the staff can answer that
9 question -- but the NRC might have difficulty, because
10 Entergy has stated clearly in the Purchase and Sale
11 Agreement that they aren't accepting responsibility
12 for remediation responsibilities that NYPA would
13 retain, particularly those off-site. And that the
14 NRC, unless they deal with this question now, if the
15 NRC did have to bring action against Entergy later,
16 would be in a compromised position of having approved
17 the license transfer without dealing with this issue
18 up-front, without putting a condition, for instance,
19 that Entergy -- you know, if there are remediation
20 responsibilities that occurred under NYPA's ownership,
21 that the only way for the NRC to ensure that they get
22 done is through forcing Entergy to do it, then the NRC
23 should put a condition on the license that says so.
24 MR. SILBERG: Mr. Bechhoefer, the real
25 problem we have here is that CAN is not willing to

1 accept the NRC's jurisdiction. The NRC specifically
2 has said in CLI-0022 that its jurisdiction does not
3 extend to the kinds of things that CAN is now worried
4 about. NRC's jurisdiction does not extend to
5 greenfielding, for instance. It may be something that
6 is important. It may be something that in fact
7 Entergy has committed to do and NYPA has committed to
8 fund. But it's not part of NRC responsibility.
9 And for us to be discussing here whether
10 we ought to change the NRC -- in essence, change the
11 NRC regulations to require someone to establish a fund
12 for something that doesn't exist because CAN is
13 concerned that maybe there are some facts that might
14 appear 20 years from now, it's an interesting
15 philosophical argument. I think it's dead wrong, but
16 it just doesn't belong in this proceeding. And I
17 think --
18 JUDGE BECHHOEFER: Well, let me ask you,
19 You just said NRC jurisdiction doesn't extend to
20 greenfielding. It certainly -- doesn't it? It's one
21 of the two forms of decommissioning.
22 MR. SILBERG: No, it is not, not within
23 NRC's scope. NRC's space, the decommissioning deals
24 only with radiological decommissioning. Greenfielding
25 means removing all traces, radiological and --

1 JUDGE BECHHOEFER: I would define
2 greenfielding as the unrestricted --
3 MR. SILBERG: Unrestricted use is a term
4 that deals only with radiological decommissioning. It
5 does not deal with non-radiological decommissioning.
6 Greenfielding has nothing to do with release for
7 unrestricted use.
8 JUDGE BECHHOEFER: I see.
9 MR. SILBERG: Greenfielding has to do with
10 restoring the site to a pristine condition, what it
11 was before the Native Americans sold Indian Point to
12 --
13 JUDGE BECHHOEFER: Oh, I was not defining
14 it in that sense. I was defining it as unrestricted
15 as distinguished from one of the restricted --
16 MR. SILBERG: Oh, certainly release for
17 unrestricted use isn't part of the NRC decommissioning
18 responsibility. That is one of the two options. Of
19 course, you have --
20 JUDGE BECHHOEFER: That's correct.
21 MR. SILBERG: -- the option under NRC
22 regulations to release for restricted use. We're not
23 talking about that here. The issue here is whether
24 you go beyond radiological decommissioning of the site
25 and deal either with non-radiological decommissioning

1 or alleged off-site accumulations of contamination
2 that somehow we have never reported and the NRC has
3 never found and don't exist, and we should be setting
4 up a fund for that. Well, that may be an interesting
5 approach to life, but it's not the NRC's current
6 regulatory structure.
7 JUDGE BECHHOEFER: Well, let me, again,
8 try to clarify. When you were referring to
9 greenfielding, were you referring to both radiological
10 and non-radiological discharges --
11 MS. KATZ: No.
12 JUDGE BECHHOEFER: -- or only
13 radiological?
14 MS. KATZ: No, only radiological. I mean
15 it's a term at least that's used in the Northeast in
16 terms of decommissioning nuclear reactors. It may be
17 different for Mr. Silberg, but in the Northeast that's
18 the terminology they're using at different sites, in
19 terms of greenfielding, which in fact means the 25
20 milirem above background radiation standard.
21 JUDGE BECHHOEFER: Did you, Mr. Judson or
22 Ms. Katz, as the case may be, discuss the relevancy or
23 concerns about either PASNY or NYPA's financial
24 strength in your Statement of Position, at page 7. In
25 light of the fact that the decommissioning fund is

1 held by the Bank of New York rather than PASNY or NYPA
2 and that the funds for the trust have already been
3 deposited with the Bank, could you discuss that? Does
4 that satisfy your concerns?
5 MR. JUDSON: Well, no, it doesn't. In
6 fact, what we're concerned about in this is that the
7 NRC very clearly, in terms of its rulemakings on
8 financial assurance for decommissioning and I believe
9 it's the Financial Assurance Regulatory Guide that we
10 reference, that what the Applicants are arguing is
11 that their decommissioning funding arrangement is
12 equivalent to prepayment. And, in fact, the
13 assumption in prepayment is that the NRC retains
14 direct regulatory authority over the holder of the
15 decommissioning fund through the license. And, in
16 fact, the staff cited this as something that
17 compromises the ability of this arrangement to satisfy
18 the same standard as prepayment.
19 On page 10 of the Indian Point 3 Safety
20 Evaluation report, "Although the staff is not aware of
21 any specific plans on the part of Entergy at Nuclear
22 IP-3, it is possible that if a deferred dismantlement
23 for decommissioning is chosen and if the IP-3 license
24 is extended, the Authority could potentially hold a
25 trust fund for 75 years even without considering

1 license renewal. This fact increases uncertainty in
2 a situation in which the NRC would not retain the same
3 type of direct regulatory authority over the Authority
4 that the NRC would have if the Authority remained a
5 licensee. In addition, although the proposal contains
6 certain similarities to a third party guarantee, the
7 Authority is not regulated or licensed as a surety
8 company."
9 Now, this whole -- the issue of the Bank
10 of New York holding the trust -- being the trustee as
11 opposed to NYPA, clearly the decommissioning trust
12 fund is in the name of the Power Authority of the
13 State of New York, and the Bank of New York is holding
14 it. What you have now is a situation where it seems
15 that the concern the staff raised in here is that the
16 NRC, in terms of financial assurance, wants to have
17 regulatory authority -- at least this is in terms of
18 the regulations that already exist -- wanted to have
19 regulatory authority over the holder of these kinds of
20 funds to make sure that they were dispersed
21 appropriately and to make sure that the licensees, in
22 fact, had direct access to the monies that they would
23 need to fund decommissioning.
24 And so the question is now that the
25 Entergy Companies not only have to have their

1 decommissioning activities approved by the NRC but
2 then that they also have to go to NYPA in order to be
3 reimbursed for them. And while there may be a degree
4 of assurance in this, in terms of there being money
5 for decommissioning, that this doesn't satisfy the
6 standard of prepayment in the NRC's regulations.
7 That's our concern is that essentially what you have
8 throughout the proposed license transfer is a series
9 of legal firewalls between the Entergy Companies and
10 responsibilities for things that they may need to
11 incur.
12 MR. SILBERG: Judge Bechhoefer, if I might
13 reply to that.
14 JUDGE BECHHOEFER: Yes. I was also going
15 to ask the staff to comment on the statement on pages
16 10 and 11 of the SER, whether that remains a problem,
17 and you may need your witnesses, I don't know.
18 MR. HOM: What would you like a response
19 to?
20 JUDGE BECHHOEFER: Well --
21 MR. HOM: The equivalency between --
22 JUDGE BECHHOEFER: No, no, no. I asked
23 that question before, and I still want to get that
24 answered.
25 MR. SILBERG: Do you want me to comment on

1 that before the staff responds or how would you like
2 to proceed?
3 JUDGE BECHHOEFER: Yes. Why don't you
4 comment on it?
5 MR. SILBERG: Okay. First --
6 JUDGE BECHHOEFER: And we're referring to
7 pages 10 and 11 of the SER.
8 MR. SILBERG: If one reads the
9 regulations, which CAN says in prepayment assume that
10 the licensee holds the trust fund, one can read the
11 regulations a hundred times and find nothing in there
12 that says that. 50.75-E1(i), defines prepayment as
13 "The deposit made preceding the start of operation
14 into an account segregated from licensee assets and
15 outside the licensee's administrative control of cash
16 or liquid assets, such that the amount of funds would
17 be sufficient to pay decommissioning costs at the time
18 termination of operation is expected. Prepayment may
19 be in the form of a trust, escrow account, government
20 fund, certification of deposit, deposit of government
21 securities or other payment acceptable to the NRC. A
22 licensee may take credit for protected earnings on the
23 prepaid fund up to two percent, et cetera, et cetera."
24 There's nothing in that definition that
25 says the licensee must hold the fund -- nothing. So

1 the assumption that CAN is making that somehow we're
2 not equivalent, assuming, as CAN does, that equivalent
3 must mean identical to, which in and of itself is
4 incorrect, is totally without basis.
5 With respect to the point that there's
6 additional uncertainty because you might wind up
7 holding the fund for 75 years, that could happen
8 whether there's a transfer or not. If the funds were
9 transferred to Entergy, Entergy might be holding the
10 funds for 75 years. The fact really becomes whether
11 the NRC staff, which said that they needed additional
12 assurances, now believes that it has those additional
13 assurances. We've heard nothing from CAN that
14 explains why the additional assurances that the staff
15 has imposed are inadequate.
16 One other point: With respect to NYPA not
17 being licensed as a trustee and somehow that
18 invalidates the equivalence, NYPA never has to be
19 licensed as a trustee under any set of circumstances.
20 The licensee is not a trustee. The trustee is the
21 trustee, and the Bank of New York is the trustee, and
22 they are properly licensed as a trustee. So the
23 equivalence between E1(iii) as a method for holding
24 the funds and our equivalent method in E1-6 really
25 fits quite well. That's all I have to say on that.

1 JUDGE BECHHOEFER: Before I go to staff,
2 Mr. Judson, one clarification. Did you address
3 PASNY's financial strength as distinguished from the
4 Bank of New York or Entergy's? Do you have views on
5 PASNY's or NYPA's, either one, financial strength?
6 MR. JUDSON: I believe the argument that
7 the Applicants referred to, in terms of what we said
8 in our brief, was that one of the arguments being used
9 to justify NYPA holding the funds is they're comparing
10 this to, I believe, it's 50.75-E1(iii), the surety
11 method, insurance or other guaranteed method. And one
12 of the arguments that was made on the behalf of both
13 the staff and the licensees was that NYPA's bond
14 ratings were so strong that essentially they were as
15 strong as most investment companies and license surety
16 entities.
17 And what we were raising is that that may
18 be true now. But in terms of the possibility that the
19 staff raised of NYPA remaining the holder of the
20 decommissioning fund for 75 years, that the
21 deregulation of the energy industry has already
22 destroyed the bond ratings of some very, very strong
23 companies in a very short period of time. And in fact
24 to speculate that NYPA's bond ratings are going to
25 remain so strong in the future is purely speculation.

1 There's nothing to indicate that engaging in the
2 really unstable market situation that's being created
3 under deregulation is going enable NYPA, five, ten
4 years from now, to be in the same stable situation it
5 is now.
6 And that what we're saying is that -- the
7 comparison we made is that these licensed surety
8 entities engage in more conservative business
9 practices than what NYPA's going to be forced to enter
10 into deregulation. And that, in fact, they're not a
11 licensed surety agency. It's just simply -- I mean
12 there's just simply no way under 50.75-E1(iii) that
13 NYPA qualifies or is equivalent to a licensed surety
14 entity.
15 JUDGE BECHHOEFER: Does the staff have any
16 -- well, first, is this -- what I asked before -- is
17 this the first transaction of its type that the staff
18 has approved where the funds are held by, essentially,
19 the selling body and the responsibility is passed to
20 the purchaser?
21 MR. HOM: There's one clear example
22 previously involving Crystal River where I believe a
23 municipality minority owner transferred its interests
24 in Crystal River to the majority licensee. And the
25 minority transferor retained decommissioning funds

1 that it had accumulated. However, factually, the
2 majority owner transferee, at least I believe in the
3 staff's safety analysis, was analyzed to be able to
4 handle the percentage increase in decommissioning
5 responsibilities that was transferred from the
6 minority owner. But that is one example where
7 permanently there was a transfer of interest in the
8 license to a transferee without the transfer of the
9 related decommissioning trust fund.
10 There were two other instances where on a,
11 essentially, temporary basis the funds were held by
12 the transferor. In one transfer involving PSE&G
13 Nuclear, I believe, there was a clear one-year limit
14 to allow a transition period and tax ruling on the
15 decommissioning trust fund transfer. And there was
16 another situation involving TMI One where the staff
17 basis for approval was -- the arrangement was
18 essentially a temporary arrangement, or at least
19 presented that way, pending a tax ruling, which was to
20 be, I believe, the first tax ruling in this area. But
21 as a matter of what in fact unfolded, the transfer
22 occurred with the transfer of decommissioning funds to
23 the transferee. So that instance there was no
24 retention by the transferor of the funds.
25 Crystal River is the clearest example of

1 a direct transfer of an interest in a license with a
2 permanent retention by the transferor of the funds.
3 JUDGE BECHHOEFER: We could have a fairly
4 brief break. Maybe we should do that. Let's have a
5 ten-minute break.
6 (Whereupon, the foregoing matter went off
7 the record at 3:10 p.m. and went back on
8 the record at 3:25 p.m.)
9 JUDGE BECHHOEFER: Back on the record. I
10 believe -- had you finished answering the question
11 that I had posed to you?
12 MR. HOM: I think you had several
13 questions, Your Honor, and I wasn't sure which
14 question we were on at this point. Were you satisfied
15 with the answer on other examples of transfers?
16 JUDGE BECHHOEFER: Right. Well, the other
17 one was a follow-up on some statements that had been
18 made by one of the two intervenors.
19 MR. HOM: Well, I have in my notes an
20 issue about prepayment and whether the proposed
21 arrangement that we're discussing now --
22 JUDGE BECHHOEFER: Yes, yes. I think that
23 was --
24 MR. HOM: -- is equivalent to a
25 prepayment. I would agree with Mr. Silberg that it is

1 not an identical arrangement. Certainly, if it were
2 an identical arrangement, we would have said it
3 essentially meets 50.75-E1 as a prepayment. It does
4 not specifically meet 50.75-E1; however, it is a
5 prepayment in the sense that there are funds actually
6 in an account, as opposed to let's, for example,
7 promise to pay funds. And in that sense, the staff
8 was analogizing it, at least, in terms of providing
9 some equivalent measure to a prepayment, in the sense
10 that there are funds in an account.
11 And I do agree with Mr. Silberg. Although
12 it is probably contemplated that the 50.75 regulation
13 applies to our licensees, there is nothing specific in
14 the regulation that says anything about exactly who is
15 holding this account. If it says anything, it says
16 outside the administrative control of the licensee.
17 MR. JUDSON: Your Honor, we have a couple
18 of other points that we'd like to address in terms of
19 this. The first, which I'll cover and then I'll hand
20 it over to Deb, is that if this arrangement were
21 really equivalent to prepayment, then the staff --
22 then we're wondering why the staff would have had to
23 impose conditions on the license transfer. The staff,
24 through imposing conditions, we believe, is an
25 acknowledgement that standing alone this arrangement

1 wouldn't be the equivalent of prepayment.

2 And we have concerns about the

3 effectiveness of conditions, at least on the license

4 transfer, of actually effecting -- making up the

5 difference between what's been proposed and what the

6 regulations require, based on the fact that,

7 especially in terms of the staff's brief in talking

8 about what action the staff could take against NYPA if

9 in fact it defaults on the conditions that have been

10 proposed and put on the license, is that the issue of

11 having to then -- I mean as it says, I believe, on --

12 where's the staff's brief? Is it this one?

13 This is on page 8 of the staff's brief.

14 "In such a case, were PASNY to disregard the substance

15 of the conditions once embodied in the trust

16 agreement, PASNY would effectively be failing or would

17 have failed to comply with the conditions of the

18 transfer approvals in the staff's view. Accordingly,

19 the approvals will become null and void, and PASNY

20 would revert to being the licensee for Fitzpatrick and

21 Indian Point 3, subject to the NRC's usual authority

22 over licensees."

23 And while legally that may be true, that

24 the staff could impose that sort of a situation on

25 NYPA, it begs the question of what would then happen

1 to the reactors themselves, especially if this happens
2 before the end of the license life. What happens to
3 the fact that Entergy is now the licensed operator?
4 Upon approval of the applications, Entergy would be
5 the licensed operator. But the notion that the staff
6 would then take an action to revert control of the
7 licenses to NYPA from Entergy really seems improbable
8 that that would actually be used as a course of
9 action.
10 And so what happens is that the NRC is in
11 a position where even its regulatory actions, as
12 described by the staff, we believe, would be
13 disadvantageous. I mean destabilizing the operation
14 of a reactor by reverting the license to the old owner
15 in the middle of the operation of it seems really
16 unlikely and really unnecessary, when the NRC could
17 clarify the situation at no risk to the availability
18 of adequate funds for decommissioning to require that,
19 at least in terms of the inflation-adjusted cost
20 amount of decommissioning within the fund, be
21 transferred to Entergy or the Entergy Companies, the
22 licensees as a condition on this license transfer.
23 It would be a much more satisfactory way
24 of ensuring that the Commission's requirements are met
25 than what's been proposed and maintains the

1 Commission's authority much more directly and more
2 clearly than the kind of situation that's being
3 created in the existing approval.
4 MR. HOM: Your Honor, I would like to
5 respond to that, if I may?
6 JUDGE BECHHOEFER: Yes, you may.
7 MR. HOM: The brief that we filed, the
8 intention was to lay out essentially the possible
9 legal theories that we believe we have to rely on to
10 address the question that you raised in the February
11 8th order. And there are essentially three theories
12 in this brief.
13 The remedy that Mr. Judson is referring to
14 certainly is one of the three; however, there are
15 caveats, particularly in footnote 12 on page 9. The
16 staff does recognize that, as a practical matter,
17 there could be some problems. It is -- certainly as
18 time goes forward, it may become an impossibility, in
19 essence. It may not be an impossibility to bring
20 PASNY or NYPA back onto the license. I don't know if
21 we're saying in this brief that we would go to the
22 status quo ante, but certainly I think we would have
23 the authority to argue that we could bring PASNY back
24 on the license without necessarily taking Entergy off
25 the license. And before any such action like that

1 were to occur, obviously the practical limitations and
2 implications would be considered by the staff and the
3 Commission.
4 The principal theories in this brief are
5 under Section 161 of the Atomic Energy Act, and that
6 is that NYPA engaging in activities over which the
7 Commission has jurisdiction would give us our direct
8 authority to issue an order to NYPA or PASNY in
9 connection with any action on the decommissioning
10 funds that they retained.
11 The second major theory are the
12 contractual provisions in the trust agreement
13 themselves, that we believe that we could take an
14 action in a court of law to enforce the agreement
15 itself.
16 So with those first two remedies available
17 to us, we would not think it would even be likely that
18 we would reach the third remedy, which Mr. Judson has
19 been focusing on today.
20 But I will note that even in the
21 regulations that govern this proceeding and the
22 Commission's decision of the license transfer, that
23 there is potentially contemplated by the Commission
24 that we may have to undo the transfer at some point.
25 And this was merely referenced as a possible theory

1 that we could use to address your issue that you've
2 raised in your order.
3 MR. SILBERG: Judge Bechhoefer, if I could
4 just add one apostrophe to that statement by Mr. Hom.
5 This is really all based on the assumption, as stated
6 in the staff's brief, that were PASNY to disregard the
7 substance of the conditions, this is again a
8 theoretical possibility that NYPA will deliberately
9 violate conditions.
10 And while I agree that there are these
11 three options out there, I think, a, there's no basis
12 for assuming that the Authority would indeed disregard
13 the substance of the conditions. And, second, there's
14 no basis for assuming that the first two regulatory
15 options that Mr. Hom outlined would not bear fruit.
16 I think the third is, from the staff's view, perhaps
17 a theoretical option. But from a practical
18 standpoint, I think it has no bearing whatsoever in
19 this case.
20 JUDGE BECHHOEFER: I think I have only one
21 further question on Contention 2, and this is a
22 hypothetical; it may or may not happen. But assuming
23 that during decommissioning or concerning an LTP there
24 were to be a requirement that -- and this is an
25 undecided -- I gather is an undecided question at the

1 moment -- whether EPA water quality standards would
2 govern, at least with respect to drinking water
3 sources, would the fund, as now defined, be sufficient
4 to finance the extra cost beyond compliances with
5 NRC's current whole body dose requirements of such
6 compliance? I ask both the staff and the licensee.
7 MR. SILBERG: I certainly don't have a
8 clue whether there would be any change. We don't have
9 the right people here to answer that off the top of
10 our heads. It's clearly not relevant to this
11 proceeding, because that is again posing costs over
12 and above the NRC minimum. But I don't know the
13 answer.
14 JUDGE BECHHOEFER: Well, it's my
15 understanding that currently there's some dispute as
16 to whether EPA's drinking water standards should apply
17 in lieu of NRC's whole body dose standard, only with
18 respect to drinking water.
19 MR. SILBERG: Yes. I don't know whether
20 there's a dispute or not.
21 JUDGE BECHHOEFER: And I don't know
22 whether there will be drinking --
23 MR. SILBERG: But what I don't have any
24 clue as to whether that would make a difference in the
25 cost of decommissioning a site.

1 JUDGE BECHHOEFER: Yes. That I have no
2 idea about.
3 MR. SILBERG: But I think, again, it's not
4 relevant here.
5 JUDGE BECHHOEFER: Well, I'm not sure it
6 isn't relevant, but so be it. Could the staff address
7 the same question? Mr. Hom?
8 MR. HOM: I don't know the answer to your
9 question. I think that the staff, when they appear as
10 witnesses, may be able to shed some background
11 information for you on that.
12 JUDGE BECHHOEFER: Okay. Well, we can
13 hold till that.
14 Do you know offhand whether there's been
15 any progress in resolving whether NRC's whole body
16 standards will replace any of the other standards,
17 such as EPA drinking water standards, which I
18 understand are much lower, but the numbers are not
19 exactly comparable?
20 MR. SILBERG: It was announced that
21 Chairman Mizerv and Administrator Whitman are supposed
22 to get together and try to air these difficulties on
23 not only this but presumably the Yaki Mountain
24 standard where EPA and NRC have been dueling back and
25 forth for quite a long time. We now have new blood in

1 the EPA, new blood in the NRC chairmanship, of recent
2 months at least, and perhaps these will be resolved,
3 but they have announced that they plan to get
4 together. But I guess this is not --
5 JUDGE BECHHOEFER: I guess nobody can
6 really know.
7 MR. SILBERG: -- this is of academic
8 interest, certainly, but --
9 MR. HOM: And the staff available here
10 cannot respond to your question, but there may be
11 other staff that could give you more information, but
12 none here.
13 MR. SILBERG: Well, it's reported in
14 "Inside NRC" of March 12 that they're supposed to meet
15 on March 15, so this is real-time kind of discussions.
16 JUDGE BECHHOEFER: Right, right. Well, I
17 just wasn't sure if I had all the information before
18 me on that subject. Mr. Judson?
19 MR. JUDSON: Your Honor, in terms of -- we
20 don't actually have a response to this issue. I'm not
21 sure that we understand it quite either. But we had
22 another issue that we responded to that the Applicants
23 had raised earlier, so at your convenience, we'd be
24 willing to resume our presentation.
25 JUDGE BECHHOEFER: Concerning Contention

1 2 --

2 MR. JUDSON: That's right.

3 JUDGE BECHHOEFER: -- or 3? Because we'll

4 get to 3.

5 MS. KATZ: We're almost there.

6 JUDGE BECHHOEFER: We're almost at 3. I'd

7 like to try to round up 2 first.

8 MS. KATZ: I mean, we just wanted to

9 raise, because Mr. Silberg presented a wonderful

10 picture about why entities shouldn't have to pay tax

11 consequences on certain of the decommissioning trust

12 funds, which is what this is all about in a lot of

13 ways. It may not be the capital gains tax, but it's

14 in terms of tax consequences.

15 And he made it sound like it was so

16 painful that some of the decommissioning money would

17 go to pay the federal government, that it really took

18 me over for a moment, and I had to agree with him.

19 But, you know, we all pay taxes, and corporations are

20 supposed to pay taxes; that's the job.

21 And to set up a situation in which one

22 company is basically protecting another company from

23 paying tax consequences for buying the reactor I don't

24 think is the NRC's job, and I don't think the NRC

25 should be in the business of helping Entergy avoid tax

1 consequences on whatever part of the decommissioning
2 trust fund that it would affect. And what they would
3 then have to do are make up the decommissioning trust
4 funds on their own, which is what their job is to do.
5 But it's not the job of the NRC to keep
6 Entergy from having to pay taxes. And all of this
7 discussion about setting this up and the consequences
8 of taking this back and putting the licensee back, all
9 of this is being set up, all of this rigmarole is just
10 so Entergy doesn't have to pay its tax obligations
11 under part of the decommissioning trust fund. And we
12 think this is not the NRC's job, and the NRC shouldn't
13 be in this business.
14 Its business is to protect the public
15 health and safety, it's to provide, assure the public
16 in fact, that it's doing its job in terms of that and
17 the public can have confidence that the NRC's major
18 concern is health and safety. And in fact it's
19 Entergy's job to show that it has the financial surety
20 to do it.
21 And if what Entergy is raising is that --
22 until now it hasn't raised -- is that there are tax
23 consequences that may in fact make it harder for it to
24 in fact pay off its debt, run the reactor, and avoid
25 penalties from NYPA, in terms of power output, then

1 that's something that may need to be discussed. But
2 we don't think the NRC should help NYPA not pay --
3 Entergy not pay taxes and allow NYPA just to sort of
4 be a shill in this situation.
5 When NYPA talks about the benefits that
6 their ratepayers are going to get, they're not making
7 it clear to us either that when they say benefits,
8 they mean that they're going to return that money to
9 the ratepayer, because that money is ratepayer money.
10 And what we're talking about is close to $800 million
11 that's sitting in excess at this point in the
12 decommissioning trust fund.
13 MR. JUDSON: Well, to clarify, it's not
14 $800 million right now.
15 MS. KATZ: Right, right.
16 MR. JUDSON: But when this deal -- when
17 the sale of these reactors to Entergy was first
18 announced, a NYPA spokesperson quoted to the press
19 that by the time the licenses -- the current operating
20 license expires, that the decommissioning fund that
21 we're talking about would be worth approximately $1.9
22 billion, was the number they were estimating. And in
23 terms of what the Entergy's and NYPA's witnesses have
24 quoted before us in their testimony, in terms of what
25 the estimated cost inflation -- inflation-adjusted

1 cost of decommissioning is for these two reactors, is
2 closer to $1.1 billion.
3 And so what is being created is a
4 situation where NYPA could potentially see a windfall
5 of $800 million, in so far as their liability for
6 paying Entergy for decommissioning expenses is limited
7 to what the NRC requires as opposed to the amount
8 that's in the fund.
9 JUDGE BECHHOEFER: Well, I have one
10 further question, which will go to the licensees.
11 This is another hypothetical. Are funds for
12 decommissioning adequate if either NYPA or Entergy
13 should decide to decommission the plants prior to the
14 end of the license term or even renewal, such as what
15 happened to Rancho Seco? If they decide to terminate
16 early, would there be sufficient funding to -- if the
17 plants prove not to be profitable or face technical
18 problems, need significant upgrades for some reason or
19 another and they decide to just give it up and
20 decommission it. And I think that's what Rancho Seco
21 did. Maybe that was wise, and maybe it wasn't given
22 current history.
23 MR. SILBERG: We can ask Mr. Smelnof since
24 he was involved in making sure that Rancho Seco shut
25 down. I suspect California today would like to have

1 its megawatts.

2 JUDGE BECHHOEFER: Well, I would think so

3 too, but who knows. Anyway, if subsequently that

4 arose.

5 MR. SILBERG: There are really two points

6 to that. One, if the plant were shut down early, it

7 does not necessarily need to be decommissioned early.

8 In fact, if Indian Point 2 continued to run, I suspect

9 people would probably want to decommission that site

10 all at once. So you would not necessarily

11 decommission the plant early. The funds would

12 continue to accumulate earnings and grow.

13 In terms of at what point would the fund

14 have enough current dollars to decommission, I don't

15 know the answer to that off the top of my head. And

16 I don't know if we have that answer here right now.

17 None of the people here know that answer off the top

18 of their head.

19 MR. JUDSON: Your Honor?

20 JUDGE BECHHOEFER: Yes.

21 MR. JUDSON: If it's helpful, we have a

22 copy of the newspaper article that ran where the NYPA

23 representative was quoted with that figure that we can

24 make available to the Commission and to the panel if

25 they wish.

1 MR. SILBERG: I'm not sure what the
2 relevance of newspaper articles is at this point in
3 the proceeding.
4 JUDGE BECHHOEFER: It's likely to be --
5 well, it is heresy. We can perhaps look at it for
6 what it's worth, but I'm not sure that would be too
7 helpful.
8 MR. SILBERG: I would object to taking yet
9 more evidence into the record at this point, long
10 after the filing deadlines have passed. I just think
11 it's setting a terrible precedent.
12 JUDGE BECHHOEFER: Well, that would be a
13 response to a question, but be that as it may, I don't
14 think it will be necessary. I posed a hypothetical
15 question, but if the answer is people don't know and
16 people here don't know, I think that's where we'll
17 leave it.
18 But I think we ought to be going on to the
19 next contention. And I guess the witnesses for
20 Contention 2 are excused.
21 In going into Contention 3, Contention 3,
22 of course, involves a good bit of proprietary
23 information. I guess we could -- well, I think we
24 should probably start by having the SER introduced
25 into the record, which the staff has its witnesses

1 here to do.

2 MR. SILBERG: Although I presume they're

3 going to introduce the proprietary version into the

4 record.

5 JUDGE BECHHOEFER: Well, I assume they'll

6 introduce both.

7 MR. SILBERG: Okay. But if they introduce

8 the proprietary, then we ought to go onto a

9 proprietary transcript so it's clear. I assume that's

10 going to be incorporated into the transcript as if

11 read too, but only to be incorporated in the

12 proprietary transcript.

13 JUDGE BECHHOEFER: Well, I'm not sure

14 about the SERs. They're a bit lengthy to incorporate

15 into the transcript.

16 MR. SILBERG: No, they're not that

17 lengthy.

18 JUDGE BECHHOEFER: Well, you know, maybe

19 you're right. I thought they were a bit lengthy and

20 we would put those in as an exhibit.

21 MR. SILBERG: Okay.

22 MR. HOM: Your Honor, I have maybe some

23 procedural questions on that.

24 JUDGE BECHHOEFER: Yes, okay.

25 MR. HOM: The cover letter, order, and SER

1 and conforming amendment, I believe, were served to
2 the parties and yourself and also our -- I can have
3 the witnesses verify this, of course -- but our Agency
4 records at this point in time they're in the ADAMS
5 system, at least the non-proprietary versions are
6 accessible. The order was published in the --
7 JUDGE BECHHOEFER: I might add, we've
8 looked for the SER, couldn't find it.
9 MR. HOM: We have an accession number, do
10 we not?
11 JUDGE BECHHOEFER: Be that as it may, we
12 circulated that preliminary certification, and we
13 couldn't find that one.
14 MR. HOM: What I was leading up to was
15 what your expectations were in terms of actually
16 introducing these documents into evidence or did you
17 need that? I would have the witnesses do that if you
18 require that. Otherwise, if they're able to testify
19 as an official Agency record at this point, I won't go
20 through that line of questioning for them.
21 JUDGE BECHHOEFER: I think the Commission
22 anticipated that the staff would introduce the SER in
23 evidence. That's my reading. It's in the record
24 someplace.
25 MR. SILBERG: From our standpoint, I don't

1 believe we need witnesses to do that. I would
2 certainly stipulate to the authenticity of the
3 documents and let them come in. I assume CAN would
4 likewise.
5 MR. JUDSON: We have no objection to that.
6 JUDGE BECHHOEFER: Well, but I would think
7 that it would be introduced as an exhibit, maybe two
8 versions. I don't know if you want to introduce both
9 versions.
10 MR. HOM: Both meaning the Fitzpatrick and
11 Indian Point 3 or you're talking the proprietary
12 versus non-proprietary?
13 JUDGE BECHHOEFER: Proprietary versus non-
14 proprietary, the SER for each and both versions.
15 MR. HOM: Well, we can certainly introduce
16 both versions into the record at this point, if that's
17 what --
18 JUDGE BECHHOEFER: Yes. I believe that we
19 don't -- well, and if we don't bind it into the record
20 as if read, there won't be proprietary information in
21 the public transcript. It will be as an exhibit. It
22 won't be bound as if read.
23 MR. HOM: Right.
24 JUDGE BECHHOEFER: And I think, generally,
25 for the SER that would be preferable. We will need a

1 separate transcript for matters that are proprietary,
2 but I don't know that introducing the documents as
3 such, accepting them into the record, will involve any
4 reference to proprietary data. It's just
5 identification of the particular documents that are
6 being introduced. I think it would be appropriate to
7 introduce them into the record.
8 MR. HOM: The complete document, at least
9 as served on the Applicants and the other parties,
10 consists of a cover letter and order, the conforming
11 amendment, which is rather voluminous, and then the
12 safety evaluations. Would you require the complete
13 document to be introduced at this point?
14 MR. SILBERG: The regulations only refer
15 to introducing into the evidence the SER.
16 JUDGE BECHHOEFER: I read the rules as not
17 requiring the license transfer documents to be
18 introduced, but I think the rules require the SER to
19 be introduced.
20 MR. HOM: Just the SER?
21 JUDGE BECHHOEFER: Just the SER. But I
22 would think that both versions, both proprietary and
23 non-proprietary, should be introduced, with the non-
24 proprietary one being referable by any member of the
25 public.

1 Yes, off the record for a minute.

2 (Whereupon, the foregoing matter went off

3 the record at 3:57 p.m. and went back on

4 the record at 3:59 p.m.)

5 JUDGE BECHHOEFER: Could you explain that

6 again, because we were basically off the record.

7 MR. HOM: Unfortunately, both versions

8 that were issued by the staff, the proprietary

9 versions and the non-proprietary versions, have

10 legends at the bottom that indicate that the document

11 may contain proprietary information. That legend is

12 also on the non-proprietary version.

13 So what I'm doing to make sure we have the

14 documents in the appropriate places, I've marked in

15 handwriting "Prop" on the upper right-hand corner of

16 the proprietary versions of each of the SEs for the

17 Fitzpatrick and the IP-3 transfer. The copies that

18 are non-proprietary do not have any handwritten

19 indication in the upper right-hand corner.

20 And I just want to show also the documents

21 -- these are the non-proprietary version.

22 MR. SILBERG: The non-proprietary?

23 MR. HOM: Yes. And I'm going to show

24 these same documents to CAN representatives. You're

25 not objecting?

1 MR. JUDSON: We're not objecting.

2 MR. HOM: Your Honor, would you like these

3 further marked for identification or can I proceed to

4 move these in evidence?

5 JUDGE BECHHOEFER: Yes. I think I want to

6 move them as Staff Exhibits 1, 2, 3, 4 or something

7 like that.

8 MR. SILBERG: Excuse me. Steve, if we're

9 going to bind these into the transcript --

10 JUDGE BECHHOEFER: No, we're not. I don't

11 think -- well, it depends. Do you think that --

12 MR. SILBERG: Well, ours, which were

13 exhibits, were bound into the transcript. But if we

14 are going to do that, then we ought to introduce the

15 non-proprietary ones and then go into proprietary

16 session, so we'll start to create a proprietary

17 transcript.

18 JUDGE BECHHOEFER: Yes. I agree with you

19 on that. Now, how many pages are they?

20 MR. HOM: So you'd like me to introduce

21 the non-proprietary versions first?

22 JUDGE BECHHOEFER: Yes. They are

23 essentially 18 pages each.

24 MR. HOM: I believe so.

25 JUDGE BECHHOEFER: If they're bound into

1 the record, they won't need exhibit numbers.

2 MR. SILBERG: But you were doing that with

3 ours. Ours were bound into the record, and you gave

4 them exhibit numbers.

5 JUDGE BECHHOEFER: Oh, okay. We'll give

6 them exhibit numbers. That would be helpful.

7 MR. SILBERG: The regulations don't say

8 these need to be exhibits, unlike the testimony. This

9 just says evidence.

10 MR. HOM: If there's not objection from

11 the parties, then I move Staff Exhibits 1 and 2 into

12 evidence.

13 JUDGE BECHHOEFER: Just to explain, Staff

14 Exhibit 1 is which reactor?

15 MR. HOM: Staff Exhibit 1 will be the

16 safety evaluation for the Fitzpatrick Reactor. Staff

17 Exhibit 2 will be the safety evaluation for the Indian

18 Point 3 Reactor.

19 MR. SILBERG: The non-proprietary version.

20 MR. HOM: The non-proprietary version.

21 JUDGE BECHHOEFER: These are non-

22 proprietary, yes. Without objection, those documents

23 will be admitted into evidence.

24 (Whereupon, the above-referred

25 to documents were marked and

1 admitted into evidence as Staff
2 Exhibit Nos. 1 and 2 for
3 identification.)
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TRANSFER OF FACILITY OPERATING LICENSE

FROM THE POWER AUTHORITY OF THE STATE OF NEW YORK

TO ENTERGY NUCLEAR FITZPATRICK AND ENTERGY NUCLEAR OPERATIONS, INC.

AND CONFORMING AMENDMENT

DOCKET NO. 50-333

JAMES A. FITZPATRICK NUCLEAR POWER PLANT

1.0 INTRODUCTION

By application submitted under cover letters dated May 11 and May 12, 2000, as supplemented by letters dated June 13, June 16, July 14, September 21, October 26, and November 3, 2000, the Power Authority of the State of New York (the Authority), Entergy Nuclear FitzPatrick, LLC (Entergy Nuclear FitzPatrick), and Entergy Nuclear Operations, Inc. (ENO) requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the transfer of Facility Operating License DPR-59 for the James A. FitzPatrick Nuclear Power Plant (FitzPatrick) from the Authority to Entergy Nuclear FitzPatrick, to possess and use, and ENO to possess, use, and operate FitzPatrick. The application also requested the approval of a conforming license amendment to reflect the proposed transfer.

As a result of the ongoing restructuring of the electric utility industry, the Authority has made the decision to exit from the business of owning and operating nuclear generating facilities. The Purchase and Sale Agreement signed by the Authority and Entergy Nuclear FitzPatrick on March 28, 2000, also includes the purchase of the Indian Point Nuclear Generating Unit No. 3 (IP3) by Entergy Nuclear Indian Point 3, LLC, and also certain assets at the White Plains Nuclear Headquarters Offices. A separate license transfer application for IP3 was submitted and is being reviewed in a separate safety evaluation.

The application was filed pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (AEA), and Sections 50.80 and 50.90 of Title 10 of the Code of Federal Regulations. The supplements to the initial application that were not specifically referenced in the Federal Register notice of the transfer and amendment request did not expand the application beyond the scope of the notice.

THIS DOCUMENT CONTAINS PROPRIETARY INFORMATION INDICATED BY SHADED TEXT ON PAGES 4, 5, AND 6.

EXHIBIT
STAFF
1

2.0 BACKGROUND

FitzPatrick is a single unit boiling water reactor owned and operated by the Authority, a corporate municipal instrumentality and political subdivision of the State of New York. The operating license was granted in 1974 and commercial operation began in July 1975. After completion of the proposed transfer, Entergy Nuclear FitzPatrick will own FitzPatrick, and ENO will operate FitzPatrick as agent for Entergy Nuclear FitzPatrick, pursuant to an operating agreement between the parties (see Enclosure 6 of the May 12, 2000 application).

Entergy Nuclear FitzPatrick and ENO are newly formed entities. Entergy Nuclear FitzPatrick is engaged principally in the business of owning all or part of one or more generating facilities and selling electric energy in the wholesale market. ENO is engaged principally in the business of operating eligible nuclear facilities. Entergy Nuclear FitzPatrick is an indirect wholly owned subsidiary of Entergy Corporation, and an indirect wholly owned subsidiary of Entergy Nuclear Holding Company #1, with its principal office located in White Plains, New York. ENO is an indirect wholly owned subsidiary of Entergy Corporation, and a direct wholly owned subsidiary of Entergy Nuclear Holding Company #2, with its principal place of business to be located in White Plains, New York. Organization charts are shown in Enclosure 7 of the May 12, 2000 application.

Entergy Corporation, with headquarters located in New Orleans, Louisiana, is a global energy company that owns, manages, or invests in power plants generating approximately 30,000 megawatts of electricity worldwide. Through its subsidiaries Entergy Corporation owns and operates six nuclear power plants at five sites - Arkansas Nuclear One Units 1 and 2, Grand Gulf Nuclear Station, River Bend Station, Waterford 3 Steam Electric Station, and the Pilgrim Nuclear Power Station.

The applicants state that upon closing of the transaction, the following events will occur, as disclosed in the Purchase and Sale Agreement (Enclosure 4 of the May 12, 2000 application):

(1) Entergy Nuclear FitzPatrick will assume title to the facility (including all equipment, spare parts, fixtures, inventory, and other property necessary for the operation and maintenance of FitzPatrick), will take title to all used and spent nuclear fuel and other licensed materials at FitzPatrick, and through its authorized agent, ENO, will assume all responsibility for the operation and maintenance of the plant.

(2) All employees within the Authority's Nuclear Generation Department, and certain other employees supporting the Nuclear Generation Department, will become employees of ENO.

(3) As part of the transaction, the Authority has entered into power purchase agreements through 2004 with Entergy Nuclear FitzPatrick where the Authority will purchase capacity and energy from FitzPatrick at pre-established rates and schedules.

(4) As of closing, the Authority will maintain the FitzPatrick decommissioning trust fund and will make the funds available for the radiological decommissioning of FitzPatrick, in accordance with a Decommissioning Agreement (Exhibit O-1 to Enclosure 4 of the May 12, 2000 application). Any additional amounts required to be contributed to the trust to meet

NRC minimum funding requirements will be the responsibility of Entergy Nuclear FitzPatrick. The Authority may elect to transfer its interest in the trust fund to Entergy Nuclear FitzPatrick at the end of the license, upon dismantlement of the unit, or if the fund becomes taxable to the Authority. In the event the Authority does not elect to transfer the trust, Entergy Nuclear Inc., an affiliate of Entergy Nuclear FitzPatrick, has agreed to decommission the plant for the lesser of the agreed upon amount or the amount in the trust.

Pursuant to 10 CFR 50.80, no license shall be transferred, directly or indirectly, through the transfer of control of a license, unless the Commission shall give its consent in writing. Such action is contingent upon the Commission's determination that the transferee is qualified to hold the license, and that the transfer is otherwise consistent with applicable provisions of law, regulations, and orders of the Commission.

3.0 FINANCIAL QUALIFICATIONS ANALYSIS

Entergy Nuclear FitzPatrick does not qualify as an electric utility under 10 CFR 50.2. However, the staff has determined that Entergy Nuclear FitzPatrick meets the financial qualifications requirements for a non-electric utility pursuant to 10 CFR 50.33(f).

A non-electric utility applicant must provide information sufficient to demonstrate its financial qualifications to carry out the activities for which the license is being sought, consistent with 10 CFR 50.33(f). The information must show the following:

(1) The applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operating costs for the period of the license. The applicant must submit estimated total annual operating costs for the first 5 years of facility operations and indicate the source of funds to cover these costs.

(2) In the case of a newly formed entity organized primarily for the purpose of operating nuclear power plants, the information must show: (a) the legal and financial relationships the applicant has or proposes to have with its stockholders or owners; (b) its financial ability to meet any contractual obligation to the entity which they have incurred or propose to incur; and (c) any information considered necessary by the Commission to enable it to determine the applicant's financial qualification.

Also, 10 CFR 50.33(k)(1) requires that Entergy Nuclear FitzPatrick must provide information as described in 10 CFR 50.75 indicating there is reasonable assurance that funds will be available to decommission FitzPatrick. The applicants' proposal for decommissioning funding assurance is discussed in Section 4.0 of this Safety Evaluation.

In the application, Entergy Nuclear FitzPatrick states that it has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for FitzPatrick for the period of the license. Entergy Nuclear FitzPatrick and the Authority signed power purchase agreements (see Exhibit K to the May 12, 2000 application) on March 28, 2000, under which Entergy Nuclear

FitzPatrick will sell 100% of the total output from FitzPatrick at fixed prices, "take or pay," through 2003, and 31% of the total output through 2004. For the remaining output in 2004 and for the full output after 2004, Entergy Nuclear FitzPatrick will pursue other firm contracts or sell any uncommitted power on the market in New York.

The following table summarizes the terms of the power purchase agreement and Entergy Nuclear FitzPatrick's expected market prices for uncommitted power, as stated in the license transfer application:

TABLE 1
Expected Market Prices for Uncommited Power

Year	Output to Contract %	Contract Price ($/Mwh)	Output to Contract %	Contract Price ($/Mwh)	Market Price ($/Mwh)
2000	45	32.00	55	29.00	N/A
2001	44	32.00	56	29.00	N/A
2002	37	32.00	63	29.00	N/A
2003	31	32.00	69	29.00	N/A
2004	31	32.00	0	N/A	[ ]
2005	0	N/A	0	N/A	[ ]

(Shaded area contains proprietary information.)

The application states that FitzPatrick is expected to be operated at an average annual capacity factor of 85%, with the sale of power expected to cover the expected operating costs with a margin of additional income over and above operating costs. (By way of comparison, FitzPatrick has had capacity factors in 1997 to 1999 of 94.7%, 73.2%, and 93.9%, respectively. This represents an average capacity factor over the last 3 years of 87.3%.) In support of the claim that there is reasonable assurance of obtaining the necessary funds to operate FitzPatrick following the sale to Entergy Nuclear FitzPatrick, the applicants have provided a proprietary FitzPatrick projected income and expenses statement for the period from 2000 to 2005.

TABLE 2
Projected Income and Expenses 2000 - 2005

($000)	2000	2001	2002	2003	2004	2005
Contract Power Sales	[ ]	[ ]	[ ]	[ ]	[ ]	0
Market Power Sales	0	0	0	0	[ ]	[ ]
Total Revenue:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
O & M *	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Fuel	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Depreciation & Amortization	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Admin & Other	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Total Oper. Expenses:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Operating Profit/(Loss):	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Interest Expense:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Income Taxes:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Net Income/(Loss):	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

Note: Assumes 9/7/00 Close (Shaded area contains proprietary information.)

The applicants have also included the following estimate of total and fixed operating expenses:

TABLE 3
Estimate of Total and Fixed Operating Expenses

($000s)	2000	2001	2002	2003	2004	2005
Total Op. Expenses	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Fixed Op. Expenses	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(6 months)	N/A					

Note: Assumes 9/7/00 Close (Shaded area contains proprietary information.)

The NRC staff conducted sensitivity analyses on the projected income statement provided by the applicants in order to judge the financial resiliency of Entergy Nuclear FitzPatrick to weaker than projected revenue. Although expense projections are the domain of the applicants, the

staff believes that the applicants' assumptions are reasonable. For example, based on the Authority's annual reports for 1994 through 1997, these projected expenses fall in line with historical trends. However, the revenue projections are sensitive to the unit's capacity factor, and projected market prices in the year 2004 and beyond.

One set of sensitivity analyses adopted the assumption that capacity factors dropped by 10 percentage points below those assumed by the applicants. With all other assumptions held constant, the staff found that Entergy Nuclear FitzPatrick, notwithstanding such assumed reduced revenues over the 5½-year projection period submitted (2000 to 2005), would have the financial capability of maintaining the unit in a safe manner.

In another set of sensitivity analyses, projected revenues for the years 2001 through 2005 were assumed to be substantially less than projected by the applicant. With all other assumptions held constant, the results showed that Entergy Nuclear FitzPatrick would be capable of sustaining a drop of 12% in revenue and still break even. However, this staff assumption, for sensitivity purposes only, seems to be unlikely given the North American Electric Reliability Council (NERC) Reliability Assessment for 1998 through 2007, dated October 1998. In the Reliability Assessment report, NERC predicts that the Northeast Power Coordinating Council (United States) (NPCC(US)), which includes FitzPatrick, will see generating capacity margins dropping from 17.3% in 1998 to 5.0% in 2007. Such a trend would indicate that market prices are subject to upward pricing pressure. Therefore, the staff finds that the applicants' assumptions for market prices are reasonable, as shrinking generating capacity margins should cause market prices of electricity to increase in the area, assuming other factors remaining equal.

Although these sensitivity analyses indicate lower earnings for Entergy Nuclear FitzPatrick if lower capacity or lower market prices are experienced compared to their forecast, Entergy Nuclear FitzPatrick should still be able to remain financially stable through the use of retained earnings. In addition, Entergy Nuclear FitzPatrick would have as an additional source of funds certain credit lines discussed later in this section.

The staff assessed how reasonable or probable these changes in rates may be for the period 2001-2005. Forecasts of electric rates in competitive markets are subject to many factors that make such predictions speculative; however, the reasonableness of various growth rates may be assessed by considering various factors that could provide some indication of future electricity prices. For example, recent trends in electricity prices can provide inferences on how such prices may continue to change in the more competitive environment expected in the electric power industry.

Data on United States retail electricity prices from the Energy Information Administration indicate that the overall price (all sales categories) has declined from its highest level in 1993 (at 6.93 cents per kWh) to 6.81 cents per kWh by 1998. The average retail price for the industrial category declined from 4.85 cents per kWh in 1993 to 4.52 cents per kWh in 1998. Considering this recent downward trend in retail prices and increasing competition in the electric power industry, the general trend of electricity prices at the retail level may continue downward in the near future. However, recent dramatic price increases in some United States electricity markets suggest that future prices may, on the contrary, increase. Thus, it is difficult to predict the direction of prices likely to be paid for FitzPatrick power in its market area. The recent downward trend in United States retail prices may not necessarily produce a significant downward influence on future FitzPatrick market prices.

The staff concludes that attempting to forecast the growth rate, or even the direction of change, for market-based prices in the FitzPatrick market area is too speculative, given the uncertainty of deregulation, and other unknown factors potentially affecting electricity capacity or prices, to be useful for its contingency analysis. But the staff's most important conclusion from this analysis is that, even if prices for FitzPatrick power were to increase at an average annual rate much lower than anticipated by Entergy Nuclear FitzPatrick, this would not preclude Entergy Nuclear FitzPatrick from operating and maintaining FitzPatrick in a manner that would protect the public health and safety.

On the basis of information contained in the application as cited above providing 5 year cost estimates and indicating the source of funds to cover these costs, the NRC staff concludes that Entergy Nuclear FitzPatrick has provided assurance of being able to obtain the funds necessary to cover the estimated operating costs for the period of the facility license in accordance with 10 CFR 50.33(f)(2). The NRC staff also finds that Entergy Nuclear FitzPatrick, as a newly-formed entity, has provided the information required by 10 CFR 50.33(f)(3), and, in summary, has demonstrated that it is financially qualified to hold the license for FitzPatrick.

At the closing of the FitzPatrick purchase, Entergy Nuclear FitzPatrick and ENO will have access to an established line of credit of $20 million from an affiliate, Entergy Global Investments, Inc. This line of credit will provide working capital, if necessary, for the operation and maintenance of FitzPatrick. In addition, up to $50 million will be provided through a line of credit from another affiliate, Entergy International Ltd. LLC. Entergy Nuclear FitzPatrick and ENO will notify the NRC if any of this $50 million line of credit is called upon to pay for costs associated with the safe operation and maintenance of FitzPatrick, including the costs of nuclear property damage insurance and any retrospective premium pursuant to 10 CFR 140.21. Enclosure 9 of the May 12, 2000 application provides financial statements for Entergy International, Ltd. LLC and Entergy Global Investments, Inc. The staff has reviewed these financial statements and concludes that these companies should be capable financially to meet their commitments to Entergy Nuclear FitzPatrick and ENO as specified in the application.

To ensure that these additional funds are available as might be necessary, the staff believes that the commitment stated in the application of lines of credit of up to $70 million for FitzPatrick should be the subject of a condition of approval of the transfer of the operating license and a corresponding condition in the license itself, essentially as follows:

> Entergy Nuclear FitzPatrick and ENO shall take no action to cause Entergy Global Investments, Inc. or Entergy International Ltd. LLC, or their parent companies, to void, cancel, or modify the $70 million contingency commitment to provide funding for the FitzPatrick plant as represented in the application for approval of the transfer of the FitzPatrick License from the Power Authority of the State of New York to Entergy Nuclear FitzPatrick and ENO, without the prior written consent of the Director, Office of Nuclear Reactor Regulation.

ENO, the proposed operator of FitzPatrick, is not seeking any ownership interest in the facility. According to the application, Entergy Nuclear FitzPatrick, as the proposed owner of FitzPatrick, has committed to assume full financial responsibility for funding the safe operation of the plant. The application states that ENO will operate FitzPatrick at cost and Entergy Nuclear FitzPatrick will reimburse ENO for its costs of operation under the terms of an Operating Agreement (see draft agreement included as Enclosure 6 to the May 12, 2000 application). Since the NRC staff has determined above that Entergy Nuclear FitzPatrick is financially qualified under

10 CFR 50.33(f) to hold the license for the FitzPatrick plant, the staff concludes that ENO has satisfied applicable financial qualification requirements and that there is no problematical financial qualifications issue with regard to ENO.

4.0 DECOMMISSIONING FUNDING ASSURANCE

The Commission has determined that decommissioning funding assurance is necessary to protect public health and safety. The applicants propose in the May 12, 2000, application, that the master decommissioning trust for FitzPatrick[1] continue to be held for the benefit of the Authority until FitzPatrick is decommissioned. The master decommissioning trust would continue to be held by the current trustee, The Bank of New York, on behalf of the Authority. The Authority also requests that it be removed as a named licensee from the FitzPatrick license at the time that the sale of FitzPatrick occurs. Thus, the Authority proposes to retain responsibilities for holding and disbursing decommissioning funds as a non-licensee that would normally be held by a licensee.

The applicants state that, although the Authority would continue to hold the decommissioning trust, "...the regulatory responsibility for the decommissioning of FitzPatrick... will always reside with Entergy Nuclear FitzPatrick." The application also states that, under the master decommissioning trust, the Authority's interest in the trust may be transferred only to the licensed owner of FitzPatrick responsible for decommissioning, and is not subject to the claims of creditors of the Authority. (See the Authority's response, dated June 13, 2000, to a staff request for additional information [Question 4].) Applicants further state that, pursuant to the Decommissioning Agreements attached to the Purchase and Sale Agreement for FitzPatrick, the Authority will retain the contractual obligation to decommission the plant. However, this obligation is limited to an amount equal to the lesser of the inflation-adjusted cost amount based on the formulas in 10 CFR 50.75(c) or the actual amount in the decommissioning fund at the time decommissioning commences. At the time decommissioning commences for the plant, the Authority would direct the trustee to disburse the funds from the trust to pay for decommissioning activities.[2]

The applicants have proffered several reasons why they believe that the Authority's continued holding of the decommissioning trust provides an adequate level of assurance, despite its not remaining a licensee. First, the applicants have agreed to amend the master decommissioning trust agreement covering FitzPatrick with the following provisions:

(1) Use of assets in the trust, in the first instance, shall be limited to the expenses related to decommissioning of FitzPatrick as defined by the NRC in its regulations

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[1] The master decommissioning trust agreement covers both the IP3 and FitzPatrick plants, with separate sub-trusts covering each plant.

[2] The provisions in the various documents appended to the license transfer application relating to the buyer's and seller's respective responsibilities for decommissioning are complex. Based on a review of the provisions in their entirety, the staff concludes that their effect is to limit the Authority's responsibilities to holding and disbursing decommissioning trust funds with the apparent purpose of attempting to limit any adverse Federal income tax consequences to the decommissioning funds.

and issuances, and as provided in the FitzPatrick license and any amendments thereto.

(2) No contribution to the trust that consists of property other than liquid assets shall be permitted.

(3) Investments in the securities or other obligations of the Authority, Entergy Corporation, Entergy Nuclear Indian Point 3, Entergy Nuclear FitzPatrick, ENO, or affiliates thereof, or their successors or assigns, shall be prohibited. Except for investments that replicate the composition of market indices or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear plants is prohibited.

(4) No disbursements or payments from the trust shall be made by the trustee until the trustee has first given the NRC 30 days' notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director of the Office of Nuclear Reactor Regulation.

(5) The trust agreement shall not be modified in any material respect without the prior written consent of the Director of the Office of Nuclear Reactor Regulation.

Second, the applicants believe that The Bank of New York, as trustee, has fiduciary duties that require it to hold and expend the funds for the purpose of decommissioning FitzPatrick. These fiduciary duties would be further strengthened by the five additional conditions previously discussed. In addition, the Authority, as a political subdivision and corporate municipal instrumentality of New York, is required to ensure that the public interest of the State of New York in the safe and complete decommissioning of FitzPatrick is carried out.

Third, the applicants believe that the proposed funding mechanism provides assurance equivalent to the mechanisms described in 10 CFR 50.75(e)(1)(iii) because it is comparable to a parent-company guarantee, a third-party guarantee, or a surety. Applicants state, "Having a fully funded decommissioning trust fund provides at least as much financial assurance as relying upon a parent company or third party guarantor (even one meeting the NRC's financial tests) or the issuer of a surety bond, line of credit or letter of credit, to adhere to its commitments years in the future."

Finally, the applicants believe that their proposal would comply with 10 CFR 50.75(e)(1)(vi), which essentially allows other funding mechanisms that the NRC determines, upon review, to provide a level of assurance that is equivalent to the other stated mechanisms.

As indicated in the application, the decommissioning trust fund for FitzPatrick as of March 31, 2000, is $336.6 million. The amount of the decommissioning trust fund meets the requirements of the "prepayment" decommissioning funding assurance mechanism in 10 CFR 50.75(e)(1)(i) using the generic formulas in 10 CFR 50.75(c). For FitzPatrick, the current amount required under 10 CFR 50.75(c) is approximately $345 million, assuming that vendor services for low-level waste disposal are used, in accordance with NUREG-1307, Revision 8, "Report on Waste Burial Charges." In addition, pursuant to the "prepayment" assurance option, a licensee or an applicant is allowed to take a 2-percent credit in real dollar terms for future earnings on its decommissioning trust fund. The proposed transferee of FitzPatrick meets the requirements of

10 CFR 50.75 if it takes the 2-percent credit. The transferee would be responsible for decommissioning costs above those not covered by the initial deposits plus future earnings.

In this case, the applicants contemplate that a non-licensee may hold decommissioning funds throughout the term of the license and the decommissioning period. As described below, the staff has concluded that reasonable assurance will be provided by requiring certain additional modifications to the trust agreement and other conditions beyond those offered by the applicants. With the addition of such conditions, the staff believes that the requirements of 10 CFR 50.75(e)(1)(vi) will be met -- namely, an assurance mechanism that "provides, as determined by the NRC upon its evaluation of the specific circumstances of each licensee submittal, assurance of decommissioning funding equivalent to that provided by the mechanisms specified in paragraphs (e)(1)(i) through (v) of this section."

In some ways, a trust held by the Authority could provide more assurance than one held by an investor-owned utility. The Authority was initially formed to develop the hydroelectric and navigational resources of those portions of the Niagara and Saint Lawrence Rivers within New York State boundaries and, subsequently, to provide baseload electric generating capacity for the benefit of the residents of New York State. Although the Authority has decided to sell its nuclear plants, it will continue to serve in the capacity for which it was originally created. As provided under New York State law, the Authority is a "corporate municipal instrumentality" of New York State and is "a political subdivision of the state, exercising governmental and public powers, perpetual in duration." (Section 1000.1 of Chapter 519, Laws of New York, 1992.) In addition, although New York State does not explicitly guarantee the Authority's bonds and other financial issuances, New York State has pledged not to limit or alter the rights it has vested in the Authority until the Authority fully performs under the contracts to which it is a party.[3] In addition, the Authority generally has maintained a bond rating of AA or equivalent from major rating agencies. This is a strong rating that reduces the potential for long-term default on the decommissioning trust funds.

On the other hand, the Authority is proposing to hold the decommissioning trust at least until 2015, when the IP3 operating license expires. (The FitzPatrick license expires in 2014.) Although the staff is not aware of any specific plans on the part of Entergy Nuclear FitzPatrick, it

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[3] Section 1011.1 of Chapter 519, Laws of New York, 1992, states--

> The state of New York does hereby pledge to and agree with the holders of any obligations issued under this title, and with those parties who may enter into contracts with the authority [NYPA] pursuant to the provisions in sub-paragraph five or six of section one thousand five above, that the state will not limit or alter the rights hereby vested in the authority until such obligations together with the interest thereon are fully met and discharged and/or such contracts are fully performed on the part of the authority, provided that nothing herein contained shall preclude such limitation or alteration if and when adequate provision shall be made by law for the protection of the holders of such obligations of the authority or those entering into such contracts with the authority. The authority as agent for the state is authorized to include this pledge and undertaking for the state in such obligations or contracts.

is possible that, if a deferred dismantlement for decommissioning is chosen and if the FitzPatrick license is extended, the Authority could potentially hold the trust fund for 75 years even without considering license renewal. This fact increases uncertainty in a situation in which the NRC would not retain the same type of direct regulatory authority over the Authority that the NRC would have, if the Authority remained a licensee. In addition, although the proposal contains certain similarities to a third party guarantee, the Authority is not regulated or licensed as a surety company.

On balance, the staff believes that, given the specific factual situation involved in the proposed license transfer and the imposition of certain conditions in addition to and beyond those proposed in the application, the applicants' proposal will meet the standard for other assurance mechanisms as specified in 10 CFR 50.75(e)(1)(vi). These additional conditions include the Authority making the following two modifications to the decommissioning trust agreement no later than the date of the license transfer to the proposed transferees:

(1) consistent with the November 3, 2000, supplement to the application, incorporate a provision that states that the provisions or purpose of the trust agreement may be enforced by the NRC against the Authority and the trustee with respect to the disbursement of the trust funds to the extent necessary to ensure compliance with or satisfaction of the NRC's decommissioning requirements. The NRC shall not be a beneficiary of the trust or of any of the trust funds, unless required by law to be so for the sole purpose of enforcing the provisions or purpose of the trust agreement as set forth above.

(2) revise Article VI to require that, notwithstanding the provision of Section 6.01(ii)(a) of the current trust agreement, the Authority may not terminate any fund established under the Master Trust except after requesting and obtaining written consent from the Director, Office of Nuclear Reactor Regulation or Director, Office of Nuclear Materials Safety and Safeguards, as appropriate. In the event of such request, the Authority shall, in addition to any other information, provide full information with respect to the intended disposition of any funds remaining in the trust.

In addition, to ensure compliance with the Commission's decommissioning requirements, the Authority has agreed in writing (supplement dated September 21, 2000 to the application) to the following two provisions (the first of which the staff will incorporate as a condition of approval of the license transfer):

(1) The Authority waives any right to deny, contest or challenge the Commission's jurisdiction over the Authority with respect to the FitzPatrick plant to the extent that there may arise in the future any matter warranting action by the Commission to ensure compliance with the Commission's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust funds and retained by the Authority.

(2) Upon the transfer of the FitzPatrick plant, and pursuant to Section 7 of the Decommissioning Agreements between Entergy Nuclear FitzPatrick, LLC, Entergy Nuclear, Inc. (the Entergy Companies), and the Authority (Exhibit O-1 and O-2 to the Purchase and Sale Agreement), Entergy Nuclear FitzPatrick will

have the sole discretion to permanently cease operations of FitzPatrick. For purposes of compliance with NRC requirements, by operation of the transfer, the Entergy companies will have sole responsibility for decommissioning FitzPatrick, and the Authority's responsibility under Commission jurisdiction with respect to FitzPatrick will be limited solely to the holding and disbursement of funds for the decommissioning of the facility. The Entergy companies will have control over all physical decommissioning activities. The above waiver and description of the Authority's responsibility only applies until the Authority transfers the decommissioning trust funds to Entergy Nuclear FitzPatrick, LLC, or until the decommissioning of FitzPatrick has been completed in accordance with NRC regulations and guidance, whichever shall first occur.

The staff believes that there are also other considerations that, when considered with the above conditions, add to a finding of reasonable assurance. First, the fiduciary duties of the trustee, the fact that decommissioning is essentially prefunded, and the existence of certain similarities to a third-party guarantee provide additional assurance that necessary funds will remain available for decommissioning when needed. For example, were Entergy Nuclear FitzPatrick to secure a surety bond as a means of demonstrating decommissioning funding assurance, the surety would be based on a contractual agreement between Entergy Nuclear FitzPatrick and the surety company. (Although The Bank of New York, as trustee, is an additional party to the applicants' proposal that would not typically be present in a surety arrangement, the staff believes that modifications to the trust as described previously will enhance the assurance of the trust agreement and make such assurance reasonably equivalent to a surety bond.) However, unlike a surety company, in which the bond is based on a promise to pay at some future time if Entergy Nuclear FitzPatrick were to default, in this situation the money would already be set aside in trust. On the other hand, surety companies are regulated by the Federal and State governments. However, the Authority's size and financial strength as an "AA"- rated company is equivalent to surety companies that are on the U.S. Department of the Treasury's "Circular 570" and thus acceptable to the NRC. Thus, the applicants' proposal in many ways provides assurance equivalent to a surety bond.

The Authority's status as a political subdivision of New York State and New York's pledge not to limit or alter the rights of the Authority until the Authority's contractual obligations are satisfied also provides reasonable assurance that the contracts between the Authority and Entergy Nuclear FitzPatrick will remain in force. The Authority's status and New York's pledge offset the possible adverse impacts on assurance potentially resulting from the long time period during which the Authority may hold the trust.

Accordingly, the staff concludes that reasonable assurance of decommissioning funding will be provided if The Bank of New York continues to hold the decommissioning trust under the current management with the Authority, provided that the Order approving the license transfer for FitzPatrick contains essentially the following conditions, with those conditions that apply to the proposed licensees also being added as conforming license conditions:

(1) For purposes of ensuring public health and safety, Entergy Nuclear FitzPatrick shall provide decommissioning funding assurance for FitzPatrick by the prepayment or equivalent method, to be held in a decommissioning trust fund for the facility, of no less than the amount required under NRC regulations at 10 CFR 50.75. Any amount held in any decommissioning trust maintained by the

Authority for FitzPatrick after the transfer of the FitzPatrick license to Entergy Nuclear FitzPatrick may be credited towards the amounts required under this paragraph.

(2) If the assets of any decommissioning trust maintained by the Authority for FitzPatrick are retained in such trust following the transfer of the FitzPatrick license to Entergy Nuclear FitzPatrick and ENO instead of being transferred to any trust established by Entergy Nuclear FitzPatrick, the Authority shall maintain the assets as retained in such trust in accordance with the application for the transfer of the FitzPatrick license.

(3) The Authority shall waive any right to deny, contest or challenge the NRC's jurisdiction over the Authority with respect to FitzPatrick to the extent that there may arise in the future any matter warranting action by the NRC to ensure compliance with the NRC's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust fund and retained by the Authority, and remain subject to the Commission's jurisdiction under Section 161 of the Atomic Energy Act to issue orders to protect health and to minimize danger to life or property regarding any and all matters concerning compliance with the Commission's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust fund and retained by the Authority, until such time as the Authority transfers the decommissioning trust fund to Entergy Nuclear FitzPatrick or the decommissioning of FitzPatrick has been completed in accordance with NRC regulations and guidance, whichever occurs first.

(4) Entergy Nuclear FitzPatrick shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for the transfer of the license for FitzPatrick and the requirements of the order approving the transfer, and consistent with this safety evaluation.

(5) Entergy Nuclear FitzPatrick, or its successors or assigns, shall take no action that would adversely affect any contract between it and the Authority for the Authority's eventual payment of decommissioning funds from the trust.

(6) Entergy Nuclear FitzPatrick, or its successors or assigns, shall inform the NRC within 30 days of any adverse developments with respect to the Authority's ownership of the decommissioning trust that could reasonably be expected to lead to a significant diminution of funds available for decommissioning FitzPatnck.

(7) The decommissioning trust agreement for FitzPatrick shall provide that:

a. The use of assets in the fund, in the first instance, shall be limited to the expenses related to decommissioning FitzPatrick as defined by the NRC in its regulations and issuances, and as provided in the FitzPatrick license and any amendments thereto.

b. No contribution to the fund that consists of property other than liquid assets shall be permitted.

c. Investments in the securities or other obligations of the Authority, Entergy Corporation, Entergy Nuclear FitzPatrick, Entergy Nuclear IP3, LLC, ENO, or affiliates thereof, or their successors or assigns, shall be prohibited. Except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

d. No disbursements or payments from the trust, other than for ordinary administrative expenses, shall be made by the trustee until the trustee has first given the NRC 30 days prior written notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation.

e. The trust agreement shall not be modified in any material respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation.

f. The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations.

g. The U.S. Nuclear Regulatory Commission may enforce the provisions or purpose of the trust agreement as discussed above.

h. The Authority may not terminate any fund established under the Master Trust for FitzPatrick except after requesting and obtaining written consent from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Materials Safety and Safeguards, as appropriate.

5.0 ANTITRUST REVIEW

The Atomic Energy Act does not require or authorize antitrust reviews of post-operating license transfer applications. Kansas Gas and Electric Co., et al. (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441 (1999). Therefore, since the transfer application postdates the issuance of the operating license for FitzPatrick, no antitrust review is required or authorized.

6.0 FOREIGN OWNERSHIP, CONTROL, OR DOMINATION

Sections 103d and 104d of the Atomic Energy Act prohibit the Commission from issuing a license for a nuclear power plant to "any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government." The Commission's regulations at 10 CFR 50.38 contain virtually identical language to implement this prohibition.

The May 12, 2000, application states that both Entergy Nuclear FitzPatrick, LLC, and ENO are newly formed companies, are Delaware corporations, have principal offices in White Plains, New York, and are indirect wholly owned subsidiaries of Entergy Corporation. Entergy Nuclear

FitzPatrick is wholly owned indirect subsidiary of Entergy Nuclear Holding Company #1 (under Entergy Nuclear New York Investment Company #2). ENO is a direct wholly owned subsidiary of Entergy Nuclear Holding Company #2. Entergy Corporation's stock will continue to be widely held and traded on the New York Stock Exchange.

The application gives the names of the principal officers and directors of Entergy Nuclear FitzPatrick and ENO and represents that all are citizens of the United States. The application also represents that neither Entergy Nuclear FitzPatrick nor ENO are owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, nor are they acting as agents or representatives of another entity. The NRC staff does not know or have reason to believe otherwise.

7.0 NUCLEAR INSURANCE AND INDEMNITY

The provisions of the Price-Anderson Act (Section 170 of the AEA) and the Commission's regulations at 10 CFR Part 140 require that the current indemnity agreement be modified to reflect Entergy Nuclear FitzPatrick and ENO as the new owner and operator of FitzPatrick.

In accordance with the Price-Anderson Act, the new licensees will also be required to provide primary insurance and participate in the secondary retrospective insurance pool. They will also be required to maintain property insurance as specified in 10 CFR 50.54(w). The information provided in the application concerning financial qualifications demonstrates that Entergy Nuclear FitzPatrick, the owner, will be able to satisfy applicable insurance requirements for itself and ENO.

Consistent with NRC practice, the staff will require Entergy Nuclear FitzPatrick and ENO to provide satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations, prior to the issuance of the amended licenses reflecting the new licensees. Because the issuance of the amended license is directly tied to the consummation of the proposed transfer, the order approving the transfer will be conditioned essentially as follows:

> Before the completion of the transfer of the facility, Entergy Nuclear FitzPatrick and ENO shall provide the Director, Office of Nuclear Reactor Regulation, satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations.

8.0 TECHNICAL QUALIFICATIONS

According to the application, all employees within the Authority's Nuclear Generation Department, which includes the onsite operating organization, will become employees of ENO. The existing plant staff will remain technically qualified after the license transfer. The application states that all groups responsible for implementation of technical support for Operation of Fitzpatrick will be maintained by ENO as currently described in the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TSs). These groups include those responsible for various functions such as maintenance, operations and engineering. The application proposes no change to the TSs concerning any matter related to plant operations of the FitzPatrick facility. The applicants further state that currently all plant departments (e.g.,

Operations, Maintenance, Chemistry, Radiation Protection, etc.) report to the Site Executive Officer, and with the purchase of FitzPatrick, and operation of it by ENO, this reporting relationship is to remain the same.

The July 14, 2000, submittal provided an organization chart and a description of part of the Entergy Corporation organization depicting the reporting and communication relationships ENO officers responsible for FitzPatrick will have within the Entergy Corporation corporate structure. This description of the reporting and communication relationships differs slightly from and supercedes the description provided in the May 12, 2000, submittal. The operational organization chart shows that the Site Executive Officer of the site reports to the Senior Vice President and Chief Operating Officer of ENO, who in turn reports to the President and Chief Executive Officer (CEO) of ENO. Upon closing of the sale, the President and CEO will also become the Chief Nuclear Officer (CNO) responsible for the safe and reliable operation of the ENO operated nuclear power plants and has no responsibility for ancillary businesses that would detract his attention from nuclear safety matters. Thus, clear management control and clear lines of authority exist at the corporate level and a corporate officer is clearly responsible for nuclear activities.

The October 26, 2000 submittal stated that the President, CEO and CNO of ENO is, in addition to being the CEO of ENO (IP3 and FitzPatrick), is also the CEO of Entergy Operations, Inc. (Waterford, River Bend, Grand Gulf and Arkansas Nuclear 1 and 2), Entergy Nuclear Generation Company (Pilgrim), and Entergy Nuclear, Inc. (Maine Yankee and Millstone Unit 1 decommissioning). As CEO of these companies, he is responsible for the safe and reliable operation of the nuclear power plants and has no responsibility for ancillary businesses that would detract his attention from nuclear safety matters. The application describes the CNO position as being, "... responsible for providing top level direction of all activities associated with the safe and reliable operation of nuclear sites ..." The resume of the individual to be the CNO provided by the applicants indicates technical and management qualifications far exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The Senior Vice President and Chief Operating Officer, "... is responsible for the implementation of all activities associated with the safe and reliable operation of nuclear sites ..." The resume for that position also indicates qualifications exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The application states that the responsibilities of the FitzPatrick Site Executive Officer include, "... direct responsibility for the day-to-day activities required for the safe, efficient and reliable operation of the nuclear facilities." The resume of the individual for this position indicates qualifications exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The applicant's submittals adequately address the relevant requirements of 10 CFR 50.40(b) and 10 CFR 50.80, as applicable. The applicant has described the proposed organization and personnel qualifications for the management of, and means for providing technical support to the plant staff for the operation of FitzPatrick after the transfer of the facility operating license from the Authority to ENO. The management and technical support organization has been reviewed and the staff concludes that ENO will have an acceptable corporate organization and adequate resources to provide technical support for the safe operation of FitzPatrick under both normal and off-normal conditions after the license transfer. The staff has reviewed the operating

organization and concludes that it will continue to provide for the integrated management of operation and maintenance activities at the site after the license transfer. The staff concludes that the ENO management and technical support organizations and the operating organization proposed for FitzPatrick after the license transfer meet the relevant criteria and, therefore, are acceptable. Accordingly, the staff finds ENO is technically qualified to be the holder of the FitzPatrick license with respect to the authority to operate FitzPatrick.

9.0 CONFORMING AMENDMENTS

In connection with the application for license transfer, the Authority, Entergy Nuclear FitzPatrick and ENO requested a conforming amendment to the license, including the TSs, that would remove references to the Authority and replace them with references to Entergy Nuclear FitzPatrick or ENO, as appropriate. No physical or operating changes to FitzPatrick are requested. Supplemental information received that was not specifically referenced in the initial Federal Register notice did not affect the applicability of the Commission's generic no significant hazards consideration determination set forth in 10 CFR 2.1315.

The changes to be made to the Operating License and TSs do no more than accurately reflect the approved transfer action, which is subject to certain conditions set forth in the Order approving the transfer that were identified and discussed earlier in this Safety Evaluation. The staff made modifications to the amendment as proposed to clarify the qualifications of the transferees and their authorizations stated in the Operating License. The Amendment involves no safety questions and is administrative in nature. Accordingly, the proposed amendment is acceptable.

9.1 Conclusion with Respect to the Conforming Amendments

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

10.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment for FitzPatrick. The State official had no comments.

11.0 ENVIRONMENTAL CONSIDERATION

The subject application is for approval of the transfer of a license issued by the NRC and approval of a conforming amendment. Accordingly, the actions involved meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with approval of the application.

12.0 CONCLUSIONS

In view of the foregoing discussion, and based upon the information and representations contained in the application, the NRC staff concludes that with the appropriate conditions discussed above, Entergy Nuclear FitzPatrick and ENO are qualified to be the license holders for FitzPatrick to the extent requested, and that the transfer of the license to Entergy Nuclear FitzPatrick and ENO is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

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Date: November 9, 2000

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TRANSFER OF FACILITY OPERATING LICENSE

FROM THE POWER AUTHORITY OF THE STATE OF NEW YORK TO

ENTERGY NUCLEAR INDIAN POINT 3, LLC, AND ENTERGY NUCLEAR OPERATIONS, INC.

AND CONFORMING AMENDMENT

DOCKET NO. 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NO. 3

1.0 INTRODUCTION

By application submitted under cover letters dated May 11 and May 12, 2000, as supplemented by letters dated June 13, June 16, July 14, September 21, October 26, and November 3, 2000, the Power Authority of the State of New York (the Authority), Entergy Nuclear Indian Point 3, LLC (Entergy Nuclear IP3), and Entergy Nuclear Operations, Inc. (ENO), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the transfer of Facility Operating License DPR-64 for the Indian Point Nuclear Generating Unit No. 3 (IP3) from the Authority to Entergy Nuclear IP3 to possess and use, and ENO to possess, use, and operate IP3. The application also requested the approval of a conforming license amendment to reflect the proposed transfer.

As a result of the ongoing restructuring of the electric utility industry, the Authority has made the decision to exit from the business of owning and operating nuclear generating facilities. The Purchase and Sale Agreement signed by the Authority and Entergy Nuclear IP3 on March 28, 2000, also includes the purchase of the James A. FitzPatrick Nuclear Power Plant (FitzPatrick) by Entergy Nuclear FitzPatrick, LLC, and also certain assets at the White Plains Nuclear Headquarters Offices. A separate license transfer application for FitzPatrick was submitted and is being reviewed in a separate safety evaluation.

The application was filed pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (AEA), and Sections 50.80 and 50.90 of Title 10 of the Code of Federal Regulations. The supplements to the initial application that were not specifically referenced in the Federal Register notice of the transfer and amendment request did not expand the application beyond the scope of the notice.

2.0 BACKGROUND

IP3 is a single unit pressurized-water reactor owned and operated by the Authority, a corporate municipal instrumentality and political subdivision of the State of New York. The unit was constructed by the Consolidated Edison Company of New York, Inc. and completed in 1976. On March 10, 1978, the Authority became the owner and operator of the facility. After

NOTE: THIS DOCUMENT CONTAINS PROPRIETARY INFORMATION INDICATED B SHADED TEXT ON PAGES 4 AND 5.

EXHIBIT
STAFF
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completion of the proposed transfer, Entergy Nuclear IP3 will own IP3, and ENO will operate IP3 as agent for Entergy Nuclear IP3, pursuant to an operating agreement between the parties (see Enclosure 6 of the May 12, 2000 application).

Entergy Nuclear IP3 and ENO are newly formed entities. Entergy Nuclear IP3 is engaged principally in the business of owning all or part of one or more generating facilities and selling electric energy in the wholesale market. ENO is engaged principally in the business of operating eligible nuclear facilities. Entergy Nuclear IP3 is an indirect wholly owned subsidiary of Entergy Corporation, and an indirect wholly owned subsidiary of Entergy Nuclear Holding Company #1, with its principal office located in White Plains, New York. ENO is an indirect wholly owned subsidiary of Entergy Corporation, and a direct wholly owned subsidiary of Entergy Nuclear Holding Company #2, with its principal place of business to be located in White Plains, New York. Organization charts are shown in Enclosure 7 of the May 12, 2000 application package.

Entergy Corporation, with headquarters located in New Orleans, Louisiana, is a global energy company that owns, manages, or invests in power plants generating approximately 30,000 megawatts of electricity worldwide. Through its subsidiaries Entergy Corporation owns and operates six nuclear power plants at five sites - Arkansas Nuclear One Units 1 and 2, Grand Gulf Nuclear Station, River Bend Station, Waterford 3 Steam Electric Station, and the Pilgrim Nuclear Power Station.

The applicants state that upon closing of the transaction, the following events will occur, as disclosed in the Purchase and Sale Agreement (Enclosure 4 of the May 12, 2000 application package):

(1) Entergy Nuclear IP3 will assume title to the facility (including all equipment, spare parts, fixtures, inventory, and other property necessary for the operation and maintenance of IP3), will take title to all used and spent nuclear fuel and other licensed materials at IP3, and through its authorized agent, ENO, will assume all responsibility for the operation and maintenance of the plant.

(2) All employees within the Authority's Nuclear Generation Department, and certain other employees supporting the Nuclear Generation Department, will become employees of ENO.

(3) As part of the transaction, the Authority has entered into power purchase agreements through 2004 with Entergy Nuclear IP3 where the Authority will purchase capacity and energy from IP3 at pre-established rates and schedules.

(4) As of closing, the Authority will maintain the IP3 decommissioning trust fund and will make the funds available for the radiological decommissioning of IP3, in accordance with a Decommissioning Agreement (Exhibit O-2 to Enclosure 4 of the May 12, 2000 application). Any additional amounts required to be contributed to the trust to meet NRC minimum funding requirements will be the responsibility of Entergy Nuclear IP3. The Authority may elect to transfer its interest in the trust fund to Entergy Nuclear IP3 at the end of the license, upon dismantlement of the unit, or if the fund becomes taxable to the Authority. In the event the Authority does not elect to transfer the trust, Entergy Nuclear Inc., an

affiliate of Entergy Nuclear IP3, has agreed to decommission the plant for the lesser of the agreed upon amount or the amount in the trust.

Pursuant to 10 CFR 50.80, no license shall be transferred, directly or indirectly, through the transfer of control of a license, unless the Commission shall give its consent in writing. Such action is contingent upon the Commission's determination that the transferee is qualified to hold the license, and that the transfer is otherwise consistent with applicable provisions of law, regulations, and orders of the Commission.

3.0 FINANCIAL QUALIFICATIONS ANALYSIS

Entergy Nuclear IP3 does not qualify as an electric utility under 10 CFR 50.2. However, the staff has determined that Entergy Nuclear IP3 meets the financial qualifications requirements for a non-electric utility pursuant to 10 CFR 50.33(f). A non-electric utility applicant must provide information sufficient to demonstrate its financial qualifications to carry out the activities for which the license is being sought, consistent with 10 CFR 50.33(f). The information must show the following:

(1) The applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operating costs for the period of the license. The applicant must submit estimated total annual operating costs for the first 5 years of facility operations and indicate the source of funds to cover these costs.

(2) In the case of a newly formed entity organized primarily for the purpose of operating nuclear power plants, the information must show: (a) the legal and financial relationships the applicant has or proposes to have with its stockholders or owners; (b) its financial ability to meet any contractual obligation to the entity which they have incurred or propose to incur; and (c) any information considered necessary by the Commission to enable it to determine the applicant's financial qualification.

Also, 10 CFR 50.33(k)(1) requires that Entergy Nuclear IP3 must provide information as described in 10 CFR 50.75 indicating there is reasonable assurance that funds will be available to decommission IP3. The applicants' proposal for decommissioning funding assurance is discussed in Section 4.0 of this Safety Evaluation.

In the application Entergy Nuclear IP3 states that it has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for IP3 for the period of the license. Entergy Nuclear IP3 and the Authority signed power purchase agreements (see Exhibit K to the May 12, 2000 application) on March 28, 2000, under which Entergy Nuclear IP3 will sell 100% of the total output from IP3 at fixed prices, "take or pay," through 2004. After 2004, Entergy Nuclear IP3 will pursue other firm contracts or sell any uncommitted power on the market in New York.

The following table summarizes the terms of the power purchase agreement and Entergy Nuclear IP3's expected market prices for uncommitted power, as stated in the license transfer application:

TABLE 1
Expected Market Prices for Uncommitted Power

Year	Output to Contract %	Contract Price ($/Mwh)	Market Price ($/Mwh)
2000	100	36.00	N/A
2001	100	36.00	N/A
2002	100	36.00	N/A
2003	100	36.00	N/A
2004	100	36.00	N/A
2005	0	N/A	[ ]

(Shaded area contains proprietary information.)

The application states that IP3 is expected to be operating at an average annual capacity factor of 85%, with the sale of power expected to cover the expected operating costs with a margin of additional income over and above operating costs. (By way of comparison, IP3 has had capacity factors in 1997 to 1999 of 51.3%, 89.8%, and 85.99% respectively. This represents an average capacity factor over the last 3 years of 75.7%, although the past 2 years have been above the stated goal of 85%.) In support of the claim that there is reasonable assurance of obtaining the necessary funds to operate IP3 following the sale to Entergy Nuclear IP3, the applicants have provided a proprietary IP3 projected income and expenses statement for the period from 2000 to 2005.

TABLE 2
Projected Income and Expenses 2000 - 2005

($000)	2000	2001	2002	2003	2004	2005
Contract Power Sales	[ ]	[ ]	[ ]	[ ]	[ ]	0
Market Power Sales	0	0	0	0	0	[ ]
Total Revenue:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
O & M	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Fuel	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Depreciation & Amortization	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Admin & Other	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Total Oper. Expenses:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Operating Profit/(Loss):	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Interest Expense:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Income Taxes:	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Net Income/(Loss):	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

Note: Assumes 9/7/00 Close *(Shaded area contains proprietary information.)*

The applicants have also included the following estimate of total and fixed operating expenses:

TABLE 3
Estimate of Total and Fixed Operating Expenses

($000s)	2000	2001	2002	2003	2004	2005
Total Op. Expenses	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Fixed Op. Expenses	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(6 months)	N/A	[ ]	[ ]	[ ]	[ ]	[ ]

Note: Assumes 9/7/00 Close *(Shaded area contains proprietary information.)*

SHADED AREAS CONTAIN PROPRIETARY INFORMATION

The NRC staff conducted sensitivity analyses on the projected income statement provided by the applicants in order to judge the financial resiliency of Entergy Nuclear IP3 to weaker than projected revenue. Although expense projections are the domain of the applicants, the staff believes that the applicants' assumptions are reasonable. For example, based on the Authority's annual reports for 1994 through 1997, these projected expenses fall in line with historical trends. However, the revenue projections are sensitive to the unit's capacity factor, and projected market prices in the year 2005 and beyond.

One set of sensitivity analyses adopted the assumption that capacity factors dropped by 10 percentage points below those assumed by the applicants. With all other assumptions held constant, the staff found that Entergy Nuclear IP3, notwithstanding such assumed reduced revenues over the 5½-year projection period submitted (2000 to 2005), would have the financial capability of maintaining the unit in a safe manner.

In another set of sensitivity analyses, projected revenues for the years 2001 through 2005 were assumed to be substantially less than projected by the applicant. With all other assumptions held constant, the results showed that Entergy Nuclear IP3 would be capable of sustaining a drop of 17% in revenue and still break even. However, this staff assumption, for sensitivity purposes only, seems to be unlikely given the North American Electric Reliability Council (NERC) Reliability Assessment for 1998 through 2007, dated October 1998. In the Reliability Assessment report, NERC predicts that the Northeast Power Coordinating Council (United States) (NPCC(US)), which includes IP3, will see generating capacity margins dropping from 17.3% in 1998 to 5.0% in 2007. Such a trend would indicate that market prices are subject to upward pricing pressure. Therefore, the staff finds that the applicants' assumptions for market prices are reasonable, as shrinking generating capacity margins should cause market prices of electricity to increase in the area, assuming other factors remaining equal.

Although these sensitivity analyses indicate lower earnings for Entergy Nuclear IP3 if lower capacity or lower market prices are experienced compared to their forecast, Entergy Nuclear IP3 should still be able to remain financially stable through the use of retained earnings. In addition, Entergy Nuclear IP3 would have, as an additional source of funds, certain credit lines discussed later in this section.

The staff assessed how reasonable or probable these changes in rates may be for the period 2001-2005. Forecasts of electric rates in competitive markets are subject to many factors that make such predictions speculative; however, the reasonableness of various growth rates may be assessed by considering various factors that could provide some indication of future electricity prices. For example, recent trends in electricity prices can provide inferences on how such prices may continue to change in the more competitive environment expected in the electric power industry.

Data on U.S. retail electricity prices from the Energy Information Administration indicate that the overall price (all sales categories) has declined from its highest level in 1993 (at 6.93 cents per kWh) to 6.81 cents per kWh by 1998. The average retail price for the industrial category declined from 4.85 cents per kWh in 1993 to 4.52 cents per kWh in 1998. Considering this recent downward trend in retail prices and increasing competition in the electric power industry, the general trend of electricity prices at the retail level may continue downward in the near future. However, recent dramatic price increases in some U.S. electricity markets suggest that future prices may, on the contrary, increase. Thus, it is difficult to predict the direction of prices likely to be paid for IP3 power in its market area. The recent downward trend in U.S. retail

prices may not necessarily produce a significant downward influence on future IP3 market prices.

The staff concludes that attempting to forecast the growth rate, or even the direction of change, for market-based prices in the IP3 market area is too speculative, given the uncertainty of deregulation, and other unknown factors potentially affecting electricity capacity or prices, to be useful for its contingency analysis. But the staff's most important conclusion from this analysis is that, even if prices for IP3 power were to increase at an average annual rate much lower than anticipated by Entergy Nuclear IP3, this does not preclude Entergy Nuclear IP3 from operating and maintaining IP3 in a manner that would protect the public health and safety.

On the basis of information contained in the application as cited above providing 5-year cost estimates and indicating the source of funds to cover these costs, the NRC staff concludes that Entergy Nuclear IP3 has provided reasonable assurance of being able to obtain the funds necessary to cover the estimated operating costs for the period of the facility license in accordance with 10 CFR 50.33(f)(2). The staff also finds that Entergy Nuclear IP3, as a newly-formed entity, has provided the information required by 10 CFR 50.33(f)(3), and, in summary, has demonstrated that it is financially qualified to hold the license for IP3.

At the closing of the IP3 purchase, Entergy Nuclear IP3 and ENO will have access to an established line of credit of $20 million from an affiliate, Entergy Global Investments, Inc. This line of credit will provide working capital, if necessary, for the operation and maintenance of IP3. In addition, up to $50 million will be provided through a line of credit from another affiliate, Entergy International Ltd. LLC. Entergy Nuclear IP3 and ENO will notify the NRC if any of this $50 million line of credit is called upon to pay for costs associated with the safe operation and maintenance of IP3, including the costs of nuclear property damage insurance and any retrospective premium pursuant to 10 CFR 140.21. Enclosure 9 of the application provides financial statements for Entergy International, Ltd. LLC and Entergy Global Investments, Inc. The staff has reviewed these financial statements and concludes that these companies should be capable financially to meet their commitments to Entergy Nuclear IP3 and ENO as specified in the application.

To ensure that these additional funds are available as might be necessary, the staff believes that the commitment stated in the application of lines of credit of up to $70 million for IP3 should be the subject of a condition of approval of the transfer of the operating license and a corresponding condition in the operating license itself, essentially as follows:

> Entergy Nuclear IP3 and ENO shall take no action to cause Entergy Global Investments, Inc. or Entergy International Ltd. LLC, or their parent companies to void, cancel, or modify the $70 million contingency commitment to provide funding for the IP3 plant as represented in the application for approval of the transfer of the IP3 license from the Power Authority of the State of New York to Entergy Nuclear IP3 and ENO, without the prior written consent of the Director, Office of Nuclear Reactor Regulation.

ENO, the proposed operator of IP3, is not seeking any ownership interest in the facility. According to the application, Entergy Nuclear IP3, as the proposed owner of IP3, has committed to assume full financial responsibility for funding the safe operation of the plant. The application states that ENO will operate IP3 at cost and Entergy Nuclear IP3 will reimburse ENO for its costs of operation under the terms of an Operating Agreement (see draft agreement included as Enclosure 6 to the application). Since the NRC staff has determined

above that Entergy Nuclear IP3 is financially qualified under 10 CFR 50.33(f) to hold the license for the IP3 unit, the staff concludes that ENO has satisfied applicable financial qualifications requirements and that there is no problematical financial qualifications issue with regard to ENO.

4.0 DECOMMISSIONING FUNDING ASSURANCE

The Commission has determined that decommissioning funding assurance is necessary to protect public health and safety. The applicants propose in the May 12, 2000 application, that the master decommissioning trust for IP3[1] continue to be held for the benefit of the Authority until IP3 is decommissioned. The master decommissioning trust would continue to be held by the current trustee, The Bank of New York, on behalf of the Authority. The Authority also requests that it be removed as a named licensee from the IP3 license at the time that the sale of IP3 occurs. Thus, the Authority proposes to retain responsibilities for holding and disbursing decommissioning funds as a non-licensee that would normally be held by a licensee.

The applicants state that, although the Authority would continue to hold the decommissioning trust, "...the regulatory responsibility for the decommissioning of IP3... will always reside with [Entergy Nuclear Indian Point 3]." The applicants also state that, under the master decommissioning trust, the Authority's interest in the trust may be transferred only to the licensed owner of IP3 responsible for decommissioning, and is not subject to the claims of creditors of the Authority. (See the Authority's response, dated June 13, 2000, to a staff request for additional information [Question 4].) Applicants further state that, pursuant to the Decommissioning Agreements attached to the Purchase and Sale Agreement for IP3, the Authority will retain the contractual obligation to decommission the plant. However, this obligation is limited to an amount equal to the lesser of the inflation-adjusted cost amount based on the formulas in 10 CFR 50.75(c) or the actual amount in the decommissioning fund at the time decommissioning commences. At the time decommissioning commences for the plant, the Authority would direct the trustee to disburse the funds from the trust to pay for decommissioning activities.[2]

The applicants have proffered several reasons why they believe that the Authority's continued holding of the decommissioning trust provides an adequate level of assurance, despite its not remaining a licensee. First, the applicants have agreed to amend the master decommissioning trust agreement covering IP3 with the following provisions:

(1) Use of assets in the trust, in the first instance, shall be limited to the expenses related to decommissioning of IP3 as defined by the NRC in its regulations and issuances, and as provided in the IP3 license and any amendments thereto.

(2) No contribution to the trust that consists of property other than liquid assets shall be permitted.

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[1] The master decommissioning trust agreement covers both the IP3 and FitzPatrick plants, with separate sub-trusts covering each plant.

[2] The provisions in the various documents appended to the license transfer application relating to the buyer's and seller's respective responsibilities for decommissioning are complex. Based on a review of the provisions in their entirety, the staff concludes that their effect is to limit the Authority's responsibilities to holding and disbursing decommissioning trust funds with the apparent purpose of attempting to limit any adverse Federal income tax consequences to the decommissioning funds.

(3) Investments in the securities or other obligations of the Authority, Entergy Corporation, Entergy Nuclear IP3, Entergy Nuclear FitzPatrick, ENO, or affiliates thereof, or their successors or assigns, shall be prohibited. Except for investments that replicate the composition of market indices or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear plants is prohibited.

(4) No disbursements or payments from the trust shall be made by the trustee until the trustee has first given the NRC 30 days notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director of the Office of Nuclear Reactor Regulation.

(5) The trust agreement shall not be modified in any material respect without the prior written consent of the Director of the Office of Nuclear Reactor Regulation.

Second, the applicants believe that The Bank of New York, as trustee, has fiduciary duties that require it to hold and expend the funds for the purpose of decommissioning IP3. These fiduciary duties would be further strengthened by the five additional conditions previously discussed. In addition, the Authority, as a political subdivision and corporate municipal instrumentality of New York, is required to ensure that the public interest of the State of New York in the safe and complete decommissioning of IP3 is carried out.

Third, the applicants believe that the proposed funding mechanism provides assurance equivalent to the mechanisms described in 10 CFR 50.75(e)(1)(iii) because it is comparable to a parent-company guarantee, a third-party guarantee, or a surety. Applicants state, "Having a fully funded decommissioning trust fund provides at least as much financial assurance as relying upon a parent company or third party guarantor (even one meeting the NRC's financial tests) or the issuer of a surety bond, line of credit or letter of credit, to adhere to its commitments years in the future."

Finally, the applicants believe that their proposal would comply with 10 CFR 50.75(e)(1)(vi), which essentially allows other funding mechanisms that the NRC determines, upon review, to provide a level of assurance that is equivalent to the other stated mechanisms.

As indicated in the application, the decommissioning trust fund for IP3 as of March 31, 2000, is $308.4 million. The amount of the decommissioning trust fund meets the requirements of the "prepayment" decommissioning funding assurance mechanism in 10 CFR 50.75(e)(1)(i) using the generic formulas in 10 CFR 50.75(c). For IP3, the current amount required under 10 CFR 50.75(c) is approximately $280 million, assuming that vendor services for low-level waste disposal are used, in accordance with NUREG-1307, Revision 8, "Report on Waste Burial Charges." In addition, pursuant to the "prepayment" assurance option, a licensee or an applicant is allowed to take a 2-percent credit in real dollar terms for future earnings on its decommissioning trust fund. The proposed transferee of IP3 meets the requirements of 10 CFR 50.75 with respect to the amount of decommissioning funds without recourse to the 2-percent credit. The transferee would be responsible for decommissioning costs above those not covered by the initial deposits plus future earnings.

In this case, the applicants contemplate that a non-licensee may hold decommissioning funds throughout the term of the license and the decommissioning period. As described below, the staff has concluded that reasonable assurance will be provided by requiring certain additional modifications to the trust agreement and other conditions beyond those offered by the applicants. With the addition of such conditions, the staff believes that the requirements of 10 CFR 50.75(e)(1)(vi) will be met -- namely, an assurance mechanism that "provides, as determined by the NRC upon its evaluation of the specific circumstances of each licensee submittal, assurance of decommissioning funding equivalent to that provided by the mechanisms specified in paragraphs (e)(1)(i) through (v) of this section."

In some ways, a trust held by the Authority could provide more assurance than one held by an investor-owned utility. The Authority was initially formed to develop the hydroelectric and navigational resources of those portions of the Niagara and Saint Lawrence Rivers within New York State boundaries and, subsequently, to provide baseload electric generating capacity for the benefit of the residents of New York State. Although the Authority has decided to sell its nuclear plants, it will continue to serve in the capacity for which it was originally created. As provided under New York State law, the Authority is a "corporate municipal instrumentality" of New York State and is "a political subdivision of the state, exercising governmental and public powers, perpetual in duration." (Section 1000.1 of Chapter 519, Laws of New York, 1992.) In addition, although New York State does not explicitly guarantee the Authority's bonds and other financial issuances, New York State has pledged not to limit or alter the rights it has vested in the Authority until the Authority fully performs under the contracts to which it is a party.[3] In addition, the Authority generally has maintained a bond rating of AA or equivalent from major rating agencies. This is a strong rating that reduces the potential for long-term default on the decommissioning trust funds.

On the other hand, the Authority is proposing to hold the decommissioning trust at least until 2015, when the IP3 operating license expires. (The FitzPatrick license expires in 2014.) Although the staff is not aware of any specific plans on the part of Entergy Nuclear IP3, it is possible that, if a deferred dismantlement for decommissioning is chosen and if the IP3 license is extended, the Authority could potentially hold the trust fund for 75 years even without considering license renewal. This fact increases uncertainty in a situation in which the NRC would not retain the same type of direct regulatory authority over the Authority that the NRC

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[3] Section 1011.1 of Chapter 519, Laws of New York, 1992, states--

> The state of New York does hereby pledge to and agree with the holders of any obligations issued under this title, and with those parties who may enter into contracts with the authority [NYPA] pursuant to the provisions in sub-paragraph five or six of section one thousand five above, that the state will not limit or alter the rights hereby vested in the authority until such obligations together with the interest thereon are fully met and discharged and/or such contracts are fully performed on the part of the authority, provided that nothing herein contained shall preclude such limitation or alteration if and when adequate provision shall be made by law for the protection of the holders of such obligations of the authority or those entering into such contracts with the authority. The authority as agent for the state is authorized to include this pledge and undertaking for the state in such obligations or contracts.

would have, if the Authority remained a licensee. In addition, although the proposal contains certain similarities to a third party guarantee, the Authority is not regulated or licensed as a surety company.

On balance, the staff believes that, given the specific factual situation involved in the proposed license transfer and the imposition of certain conditions in addition to and beyond those proposed in the application, the applicants' proposal will meet the standard for other assurance mechanisms as specified in 10 CFR 50.75(e)(1)(vi). These conditions include the Authority making the following two modifications to the decommissioning trust agreement no later than the date of the license transfer to the proposed transferees:

(1) consistent with the November 3, 2000, supplement to the application, incorporate a provision that states that the provisions or purpose of the trust agreement may be enforced by the NRC against the Authority and the trustee with respect to the disbursement of the trust funds to the extent necessary to ensure compliance with or satisfaction of the NRC's decommissioning requirements. The NRC shall not be a beneficiary of the trust or of any of the trust funds, unless required by law to be so for the sole purpose of enforcing the provisions or purpose of the trust agreement as set forth above.

(2) revise Article VI to require that, notwithstanding the provision of Section 6.01(ii)(a) of the current trust agreement, the Authority may not terminate any fund established under the Master Trust except after requesting and obtaining written consent from the Director, Office of Nuclear Reactor Regulation or Director, Office of Nuclear Materials Safety and Safeguards, as appropriate. In the event of such request, the Authority shall, in addition to any other information, provide full information with respect to the intended disposition of any funds remaining in the trust.

In addition, to ensure compliance with the Commission's decommissioning requirements, the Authority has agreed in writing (supplement dated September 21, 2000, to the application) to the following two provisions (the first of which the staff will incorporate as a condition of approval of the license transfer):

(1) The Authority waives any right to deny, contest or challenge the Commission's jurisdiction over the Authority with respect to the IP3 plant to the extent that there may arise in the future any matter warranting action by the Commission to ensure compliance with the Commission's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust funds and retained by the Authority.

(2) Upon the transfer of the IP3 plant, and pursuant to Section 7 of the Decommissioning Agreements between Entergy Nuclear IP3, LLC, Entergy Nuclear Operations, Inc. (the Entergy companies), and the Authority (Exhibit O-1 and O-2 to the Purchase and Sale Agreement), Entergy Nuclear IP3 will have the sole discretion to permanently cease operations of IP3. For purposes of compliance with NRC requirements, by operation of the transfer, the Entergy companies will have sole responsibility for decommissioning IP3 and the Authority's responsibility under Commission jurisdiction with respect to IP3 will be

limited solely to the holding and disbursement of funds for the decommissioning of the facility. The Entergy companies will have control over all physical decommissioning activities. The above waiver and description of the Authority's responsibility only applies until the Authority transfers the decommissioning trust funds to Entergy Nuclear IP3, or until the decommissioning of IP3 has been completed in accordance with NRC regulations and guidance, whichever shall first occur.

The staff believes that there are also other considerations that, when considered with the above conditions, add to a finding of reasonable assurance. First, the fiduciary duties of the trustee, the fact that decommissioning is essentially prefunded, and the existence of certain similarities to a third-party guarantee provide additional assurance that necessary funds will remain available for decommissioning when needed. For example, were Entergy Nuclear IP3 to secure a surety bond as a means of demonstrating decommissioning funding assurance, the surety would be based on a contractual agreement between Entergy Nuclear IP3 and the surety company. (Although The Bank of New York, as trustee, is an additional party to the applicants' proposal that would not typically be present in a surety arrangement, the staff believes that modifications to the trust as described previously will enhance the assurance of the trust agreement and make such assurance reasonably equivalent to a surety bond.) However, unlike a surety company, in which the bond is based on a promise to pay at some future time if Entergy Nuclear IP3 were to default, in this situation the money would already be set aside in trust. On the other hand, surety companies are regulated by the Federal and State governments. However, the Authority's size and financial strength as an "AA"- rated company is equivalent to surety companies that are on the U.S. Department of the Treasury's "Circular 570" and thus acceptable to the NRC. Thus, the applicants' proposal in many ways provides assurance equivalent to a surety bond.

The Authority's status as a political subdivision of New York State and New York's pledge not to limit or alter the rights of the Authority until the Authority's contractual obligations are satisfied provide reasonable assurance that the contracts between the Authority and Entergy Nuclear IP3 will remain in force. The Authority's status and New York's pledge offset the possible adverse impacts on assurance potentially resulting from the long time period during which the Authority may hold the trust.

Accordingly, the staff concludes that reasonable assurance of decommissioning funding will be provided if The Bank of New York continues to hold the decommissioning trust under the current arrangement with the Authority, provided that the Order approving the license transfer for IP3 contains essentially the following conditions, with those conditions that apply to the proposed licensees also being added as conforming license conditions:

(1) For purposes of ensuring public health and safety, Entergy Nuclear IP3 shall provide decommissioning funding assurance for IP3 by the prepayment or equivalent method, to be held in a decommissioning trust fund for the facility, of no less than the amount required under NRC regulations at 10 CFR 50.75. Any amount held in any decommissioning trust maintained by the Authority for IP3 after the transfer of the IP3 license to Entergy Nuclear IP3 may be credited towards the amounts required under this paragraph.

(2) If the assets of any decommissioning trust maintained by the Authority for IP3 are retained in such trust following the transfer of the IP3 license to Entergy Nuclear IP3 and ENO instead of being transferred to any trust established by Entergy Nuclear IP3, the Authority shall maintain the assets as retained in such trust in accordance with the application for the transfer of the IP3 license.

(3) The Authority shall waive any right to deny, contest or challenge the NRC's jurisdiction over the Authority with respect to IP3 to the extent that there may arise in the future any matter warranting action by the NRC to ensure compliance with the NRC's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust fund and retained by the Authority, and remain subject to the Commission's jurisdiction under Section 161 of the Atomic Energy Act to issue orders to protect health and to minimize danger to life or property regarding any and all matters concerning compliance with the Commission's decommissioning requirements regarding the disposition and use of the amounts accumulated in the decommissioning trust fund and retained by the Authority, until such time as the Authority transfers the decommissioning trust fund to Entergy Nuclear IP3 or the decommissioning of IP3 has been completed in accordance with NRC regulations and guidance, whichever occurs first.

(4) Entergy Nuclear IP3 shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for the transfer of the license for IP3 and the requirements of the order approving the transfer, and consistent with this safety evaluation.

(5) Entergy Nuclear IP3, or its successors or assigns, shall take no action that would adversely affect any contract between it and the Authority for the Authority's eventual payment of decommissioning funds from the trust.

(6) Entergy Nuclear IP3, or its successors or assigns, shall inform the NRC within 30 days of any adverse developments with respect to the Authority's ownership of the decommissioning trust that could reasonably be expected to lead to a significant diminution of funds available for decommissioning IP3.

(7) The decommissioning trust agreement for IP3 shall provide that:

a. The use of assets in the fund, in the first instance, shall be limited to the expenses related to decommissioning IP3 as defined by the NRC in its regulations and issuances, and as provided in the IP3 license and any amendments thereto.

b. No contribution to the fund that consists of property other than liquid assets shall be permitted.

c. Investments in the securities or other obligations of the Authority, Entergy Corporation, Entergy Nuclear IP3, Entergy Nuclear FitzPatrick, LLC, ENO, or affiliates thereof, or their successors or assigns, shall be prohibited. Except for investments tied to market indexes or other non-

nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

d. No disbursements or payments from the trust, other than for ordinary administrative expenses, shall be made by the trustee until the trustee has first given the NRC 30 days prior written notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation.

e. The trust agreement shall not be modified in any material respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation.

f. The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations.

g. The U.S. Nuclear Regulatory Commission may enforce the provisions or purpose of the trust agreement as discussed above.

h. The Authority may not terminate any fund established under the Master Trust for IP3 except after requesting and obtaining written consent from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Materials Safety and Safeguards, as appropriate.

5.0 ANTITRUST REVIEW

The Atomic Energy Act does not require or authorize antitrust reviews of post-operating license transfer applications. Kansas Gas and Electric Co., et al. (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441 (1999). Therefore, since the transfer application postdates the issuance of the operating license for IP3, no antitrust review is required or authorized.

6.0 FOREIGN OWNERSHIP, CONTROL, OR DOMINATION

Sections 103d and 104d of the Atomic Energy Act prohibit the Commission from issuing a license for a nuclear power plant to "any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government." The Commission's regulations at 10 CFR 50.38 contain virtually identical language to implement this prohibition.

The May 12, 2000, application states that both Entergy Nuclear IP3 and ENO are newly formed companies, are Delaware corporations, have principal offices in White Plains, New York, and are indirect wholly-owned subsidiaries of Entergy Corporation. Entergy Nuclear IP3 is a wholly-owned indirect subsidiary of Entergy Nuclear Holding Company #1 (under Entergy Nuclear New York Investment Company #1). ENO is a direct wholly-owned subsidiary of Entergy Nuclear Holding Company #2. Entergy Corporation's stock will continue to be widely held and traded on the New York Stock Exchange.

The application gives the names of the principal officers and directors of Entergy Nuclear IP3 and ENO and represents that all are citizens of the United States. The application also states that neither Entergy Nuclear IP3 nor ENO are owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, nor are they acting as agents or representatives of another entity. The NRC staff does not know or have reason to believe otherwise.

7.0 NUCLEAR INSURANCE AND INDEMNITY

The provisions of the Price-Anderson Act (Section 170 of the AEA) and the Commission's regulations at 10 CFR Part 140 require that the current indemnity agreement be modified to reflect Entergy Nuclear IP3 and ENO as the new owner and operator of IP3.

In accordance with the Price-Anderson Act, the new licensees will also be required to provide primary insurance and participate in the secondary retrospective insurance pool. They will also be required to maintain property insurance as specified in 10 CFR 50.54(w). The information provided in the application concerning financial qualifications demonstrates that Entergy Nuclear IP3, the owner, will be able to satisfy applicable insurance requirements for itself and ENO.

Consistent with NRC practice, the staff will require Entergy Nuclear IP3 and ENO to provide satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations, prior to the issuance of the amended licenses reflecting the new licensees. Because the issuance of the amended license is directly tied to the consummation of the proposed transfer, the order approving the transfer will be conditioned essentially as follows:

> Before the completion of the transfer of the facility, Entergy Nuclear IP3 and ENO shall provide the Director, Office of Nuclear Reactor Regulation, satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations.

8.0 TECHNICAL QUALIFICATIONS

According to the application, all employees within the Authority's Nuclear Generation Department, which includes the onsite operating organization, will become employees of ENO. The existing plant staff will remain technically qualified after the license transfer. The application states that all groups responsible for implementation of technical support for operation of IP3 will be maintained by ENO as currently described in the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TSs). These groups include those responsible for various functions such as maintenance, operations and engineering. The application proposes no change to the TSs concerning any matter related to operations of IP3. The applicants further state that currently all plant departments (e.g., Operations, Maintenance, Chemistry, Radiation Protection, etc.) report to the Site Executive Officer, and with the purchase of IP3 by Entergy Nuclear IP3 and operation of it by ENO, this reporting relationship is to remain the same.

The July 14, 2000, submittal provided an organization chart for ENO, and a description of part of the Entergy Corporation organization, depicting the reporting and communication

relationships ENO officers responsible for IP3 will have within the Entergy corporate structure. This description of the reporting and communication relationships differs slightly from and supercedes the description provided in the May 11 and May 12, 2000, submittals. The operational organization chart shows that the Site Executive Officer of the site reports to the Senior Vice President and Chief Operating Officer of ENO, who in turn reports to the President and Chief Executive Officer (CEO) of ENO. Upon closing of the sale, the President and CEO will also become the Chief Nuclear Officer (CNO) responsible for the safe and reliable operation of the ENO operated nuclear power plants and has no responsibility for ancillary business that would detract his attention from nuclear safety matters. Thus, clear management control and clear lines of authority exist at the corporate level and a corporate officer is clearly responsible for nuclear activities.

The October 26, 2000 submittal stated that the President, CEO and CNO of ENO is, in addition to being the CEO of ENO (IP3 and FitzPatrick), is also the CEO of Entergy Operations, Inc. (Waterford, Riverbend, Grand Gulf, and Arkansas Nuclear 1 and 2), Entergy Nuclear Generation Company (Pilgrim), and Entergy Nuclear, Inc. (Maine Yankee and Millstone Unit 1 decommissioning). As CEO of these companies, he is responsible for the safe and reliable operation of the nuclear power plants and has no responsibility for ancillary businesses that would detract his attention from nuclear safety matters. The application describes the CNO position as being, "... responsible for providing top level direction of all activities associated with the safe and reliable operation of nuclear sites ..." The resume of the individual to be the CNO, provided by the applicants, indicates technical and management qualifications far exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The Senior Vice President and Chief Operating Officer, "... is responsible for the implementation of all activities associated with the safe and reliable operation of nuclear sites ..." The resume of the individual for that position also indicates qualifications exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The application states that the responsibilities of the IP3 Site Executive Officer include, "... direct responsibility for the day-to-day activities required for the safe, efficient and reliable operation of the nuclear facilities." The resume of the individual for this position indicates qualifications exceeding the highest level manager qualifications endorsed by Regulatory Guide 1.8.

The applicant's submittals adequately address the relevant requirements of 10 CFR 50.40(b) and 10 CFR 50.80, as applicable. The applicant has described the proposed organization and personnel qualifications for the management of, and means for providing technical support to the plant staff for the operation of IP3 after the transfer of the facility operating license from the Authority to ENO. The management and technical support organization has been reviewed and the staff concludes that ENO will have an acceptable corporate organization and adequate resources to provide technical support for the safe operation of IP3 under both normal and off-normal conditions after the license transfer. The staff has reviewed the operating organization and concludes that it will continue to provide for the integrated management of operation and maintenance activities at the site after the license transfer. The staff concludes that the ENO management and technical support organizations and the operating organization proposed for IP3 after the license transfer meet the relevant criteria, and therefore, are acceptable. Accordingly, the staff finds ENO is technically qualified to be the holder of the IP3 license with respect to the authority to operate IP3.

9.0 CONFORMING AMENDMENTS

In connection with the application for license transfer, the Authority, Entergy Nuclear IP3 and ENO requested a conforming amendment to the license, including the TSs that would remove references to the Authority and replace them with references to Entergy Nuclear IP3 or ENO, as appropriate. No physical or operating changes to IP3 are requested. Supplemental information received that was specifically referenced in the initial Federal Register notice did not affect the applicability of the Commission's generic no significant hazards consideration determination set forth in 10 CFR 2.1315.

The changes to be made to the Operating License and TSs do no more than accurately reflect the approved transfer action, which is subject to certain conditions set forth in the Order approving the transfer that were identified and discussed earlier in this Safety Evaluation. The staff made modifications to the Amendment as proposed to clarify the qualifications of the transferees and their authorizations stated in the Operating License. The Amendment involves no safety questions and is administrative in nature. Accordingly, the proposed amendment is acceptable.

9.1 Conclusion with Respect to the Conforming Amendments

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

10.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment for IP3. The State official had no comments.

11.0 ENVIRONMENTAL CONSIDERATION

The subject application is for approval of the transfer of a license issued by the NRC and approval of a conforming amendment. Accordingly, the actions involved meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with approval of the application.

12.0 CONCLUSIONS

In view of the foregoing discussion, and based upon the information and representations contained in the application, the NRC staff concludes that with the appropriate conditions discussed above, Entergy Nuclear IP3 and ENO are qualified to be the license holders for IP3 to the extent requested, and that the transfer of the license to Entergy Nuclear IP3 and ENO is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

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D. Barss

Date: November 9, 2000

1 MR. HOM: Then I'm going to have the
2 reporter mark -- I'm not sure if we want this done at
3 this time or at some point in time later -- the
4 proprietary versions I have.
5 MR. SILBERG: Are we ready to go into
6 proprietary session?
7 JUDGE BECHHOEFER: Well, are all -- I'm
8 not sure all my questions are going to be proprietary,
9 but do you think it would be easier to do the entire
10 Issue 3 in proprietary session? Maybe that's less
11 confusing. Does everybody who's in the room, are they
12 all --
13 MR. SILBERG: Now, at this point, if we're
14 going to go to proprietary session, there are some
15 people, including our friends from the Power
16 Authority, who we would ask to leave, including
17 members of the press and CAN participants probably as
18 well.
19 JUDGE BECHHOEFER: We're now proceeding
20 into a proprietary session. Okay. Off the record.
21 (Whereupon, at 4:04 p.m., the NRC Hearing
22 went into Proprietary Session.)
23
24
25

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Port Authority of the State of New York and Entergy Nuclear Fitzpatrick, LLC

Docket Number: 50-333-LT et al.

Location: White Plains, New York

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

Jason Fabrikant
Official Reporter
Neal R. Gross & Co., Inc.