ACRST- 2006

ORIGINAL

OFFICIAL TRANSCRIPT OF PROCEEDINGS

O/I TR04 (ACRS)
RETURN ORIGINAL TO
B.J.WHITE, ACRS-P-315

THANKS! BARBARA JO
#27288

Agency: Nuclear Regulatory Commission
Advisory Committee on Reactor Safeguards

Title: 410th ACRS Meeting

Docket No.

LOCATION: Bethesda, Maryland

DATE: Friday, June 10, 1994 PAGES: 183 - 340

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PUBLIC NOTICE BY THE

UNITED STATES NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFECUARDS

DATE: June 10, 1994

The contents of this transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards, (date) June 10, 1994, as Reported herein, are a record of the discussions recorded at the meeting held on the above date.

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

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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410th ACRS Meeting

U.S. Nuclear Regulatory Commission

7920 Norfolk Avenue

Conference Room P-110

Bethesda, Maryland

Friday, June 10, 1994

The above-entitled proceedings commenced at 8:30 a.m., pursuant to notice, T. Kress, chairman, presiding.

MEMBERS PRESENT FOR THE ACRS FULL COMMITTEE:

Thomas S. Kress, Chairman

William J. Lindblad, Vice Chairman

James C. Carroll	Ivan Catton
Peter R. Davis	Robert L. Seale
William J. Shack	Charles J. Wylie
Dana A. Powers	Carlyle Michelson

DESIGNATED FEDERAL OFFICIAL: Sam Duraiswamy

P R O C E E D I N G S

[8:30 a.m.]

MR. KRESS: The meeting will now come to order, please.

This is the second day of the 410th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the committee will discuss and/or hear reports on the following:

(1) The valve operability program:

(2) Operating experience;

(3) Reconciliation of ACRS comments and recommendations;

(4) AEOD report on Potter & Brumfield motor-driven relay failures;

(5) Future ACRS activities;

(6) Strategic planning; and

(7) Proposed ACRS reports.

This meeting is being in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the Designed Federal Official for the initial portion of the meeting.

We have received no written statements or requests for time to make oral statements from members of the public regarding today's sessions.

A transcript of portions of the meeting is being kept and is requested that each speaker use one of the microphones, identify himself and speak with sufficient clarity and volume so that he can be readily heard.

I have no other items of interest.

Do any of the members have anything they want to bring up before we start?

MR. MICHELSON: I was reminded I have something to bring up. We discussed yesterday the enclosure that we were working on at one time for the boiling water reactor and it contained a number of items that now will be incorporated into Bill Lindblad's draft and I just want to bring to your attention there is a large blue package at your desk -- pardon me, a large pick package at your desk --

MR. LINDBLAD: It is a girl.

MR. MICHELSON: Right. It was a draft of the original closure and that could be your starting point to save yourself a little work or at least to see if it is of interest.

MR. KRESS: The members are aware we will finish up today.

MR. LINDBLAD: Mr. Chairman, there are a couple of us who are going to stay over on Saturday morning to read some classified submittals. The Staff is accommodating us on that.

MR. MICHELSON: We have somebody to open the safe?

MR. DURAISWAMY: Yes.

MR. KRESS: The naval reactors. The first topic of the morning is the valve operability program. Carlyle, I believe this is yours.

MR. MICHELSON: Thank you, Mr. Chairman. Just for a slight amount of history. We had a subcommittee meeting last October and in Tab 8 of your book is the minutes of the subcommittee meeting and some other background material for this subject.

After the subcommittee meeting I suggested to the full committee that they might like to get an updating on the status of the motor operated valve situation because it had been quite a while since we had heard last.

For one reason or another we had to keep kind of moving it out and then I asked that it be moved out even further to today because there was an international meeting in April in which there was an opportunity to see a large amount of foreign experience that I think we ought to hear about.

Tom Scarbrough, who will make the presentation, is going to talk to us today about an update on the situation and also the foreign experience. So, Tom?

MR. SCARBROUGH: Thank you. My name is Tom Scarbrough. I am in the Mechanical Engineering Branch of the Office of NRR and we have come down here periodically to brief you on our activities. We have quite a bit of activities ongoing to improve the performance in motor operated valves and I'll try to go through those today.

[Slide]

MR. SCARBROUGH: A little bit of background for you in terms of the regulatory bases for our activities.

We feel that the requirements for the valves to perform properly are very well founded in the NRC regulations. There's a requirement that components, safety-related components, be designed, manufactured, installed, tested and maintained to be able to perform their safety functions and examples of the applicable criteria in Appendix B to 10 CFR, Part 50 are Criterion III on design control, Criterion V on instructions, procedures and drawings, Criterion XI on test control, XII on control and measuring of test equipment, and XVI on corrective action, so these are the foundation requirements which we judge the performance of the Licensees by.

[Slide.]

MR. SCARBROUGH: A few years ago it was decided that there needed to be more activity in terms of motor operated valves than currently ongoing with those components in nuclear power plants. There was a number of failures, the Davis-Besse event.

There were some test results from Idaho National

Laboratory performed for the NRC which indicated that the stress requirements were much greater than the valve vendors had predicted and as a result of that and a bulletin, 85-03, the results of that bulletin which asked licensees to address certain high-pressure motor-operated valves, there was a development of Generic Letter 89-10 in June of 1989 which requested Licensees to establish programs that ensure the capability of all MOVs in safety-related systems to perform their safety functions.

There's five specific recommendations of the generic letter: Review and document the design basis for the operation of each valve; review and revise the methods for selecting and setting the MOV switches; test MOVs at design basis differential pressure and flow conditions where practicable and justify alternatives where such testing is not practicable; and verify the adequate torque switch settings periodically every five years or three outages and following maintenance; and finally analyze each MOVv failure, justify corrective action and trend results with a review every two years.

MR. MICHELSON: Tom, just to put this in the correct time sequence, when did the Wylie tests take place?

MR. SCARBROUGH: They were in 1988-89 timeframe.

MR. MICHELSON: And just to remind the committee, it was during the Wylie tests that we tested the reactor water cleanup valves to find out what they would do if you were to break a pipe downstream and I think that was the test that finally convinced people that there could be a potentially serious safety issue and then 89-10 cranked on it from there.

MR. SCARBROUGH: That's right. There was a Generic Issue 87 which the Office of Research was working on which had dealt with the reactor water cleanup valves where those tests originated.

[Slide.]

MR. SCARBROUGH: The schedule for the generic letter was five years or three refueling outages. That brings us to June 28th, 1994 or three outages, whichever is later, so we have a number of plants that are approaching completion of their program and I'll talk about those later as we get into the status where everybody is.

There's been numerous supplements to the generic letter, all of them for a reason but there have been many of them.

Supplement 1 provided the results of public workshops which were held right after the generic letter was issued back in 1989. There was numerous questions about what we meant by what was in the generic letter. It's a rather massive program to basically requalify or qualify in some cases for the first time motor operated valves in the power plants.

Numerous amounts of testing, evaluations and such that needed to take place so there was a lot of questions on the scope and the intent of the generic letter.

In Supplement 1 we answered those questions so we limited the scope of the generic letter to things like piping systems, eliminating the air ducting type systems.

We limited consideration of valve positioning, mispositioning to inadvertent operation from the control room. We discussed factors to be considered and limitations and justifying acceptability of alternatives to in situ testing. There was a lot of questions on that -- what would be acceptable in lieu of an in situ test under design basis conditions and emphasized the recommendation to follow a two-stage approach which came out of some of our discussions with ACRS in terms of the need to set up the valves the best you can if you were not able to do a design-basis test on the valve initially and justifying an alternative later.

Supplement 2 basically allowed additional time for Licensees to implement or incorporate all of that information into their programs and did not really impose any new requirements.

MR. MICHELSON: Wasn't this about the time in history when many Licensees began to appreciate that they really were not sure what the design basis even was for the valves and they had to go back and recreate it to make sure that the test was exemplifying what the design requirements should have been?

In many cases it simply was not specified.

MR. SCARBROUGH: That's right. There was a lot of review to go back and determine what the actual difference in pressure requirements were for these valves. In some cases Licensees took a very simplistic approach of assuming, like in the case of the Farley plant, the strength of the pipe. That was their DP that they were shooting for just for simplicity because to go back and recreate a DP evaluation was even more difficult, but other Licensees looked at more actual DP requirements.

Supplement 3 resulted directly from those tests performed on the HPCI, RCIC and RWCU valves.

[Slide.]

MR. SCARBROUGH: The high pressure coolant injection, the reactor core isolation cooling and the reactor water cleanup systems. This is a Generic Issue 87 testing that was undertaken for the NRC by INEL, the Idaho National Engineering Laboratory, and we reviewed the results of those tests.

There was a public workshop where we reviewed that information. We discussed it with the BWR Licensees which those valves are directly applicable and decided that it was appropriate for BWR Licensees to take an advance look at those specific valves in their programs in lieu of the five year schedule.

In response to Supplement 3 the BWR Licensees established criteria to determine whether deficiencies existed in those MOVs in those systems and identify valves where additional work or deficiencies were apparent.

The BWR Licensees had performed all those evaluations. We reviewed all of them. The net result of that kind of a count, we got a rough count from the Licensees as to how many valves were modified or such. Roughly half of the 200 valves from the scope were modified or adjusted in some fashion to improve their output capabilities so there was quite a bit of work.

MR. MICHELSON: 200 per plant.

MR. SCARBROUGH: 200 total because this was only six valves -- this is Supplement 3 valves.

MR. MICHELSON: Oh, these are just the Supplement 3, okay.

MR. SCARBROUGH: I should have made that more clear.

MR. MICHELSON: So the industry had 200 valves?

MR. SCARBROUGH: Right. It's kind of a coincidence but roughly it is about 200 valves per the BWR plants.

[Slide.]

MR. SCARBROUGH: That program is over with. We are pleased with the Licensees' response to Supplement 3 and we think it improved the safety quite a bit to get those valves taken care of, at least initially but there is always some follow-on work for those because they were using the best available information at the time to set up those valves and as more and more testings come in sometimes they have had to go back and readjust them, but we think the net result was a significant benefit to safety from Supplement 3.

Supplement 4 resulted from a request from the BWR Owners Group for the NRC Staff to reconsider that recommendation in Generic Letter 89-10 on the need to address inadvertent MOV operation from the control room.

As a result of that request the Staff contracted Brook Haven National Laboratory to do a study of core melt probability resulting from inadvertent operation of an MOV in a BWR plant and it resulted that it was decided that we could remove that recommendation of the generic letter, although we stated in Supplement 4 that we consider that such consideration would benefit safety, but we also emphasized that there were other aspects of mispositioning that may also need to be addressed.

For example, fire protection -- there's shorting and things like that that takes place, may take place during fires and such that need to be addressed and so that is an area we wanted to emphasize to them.

MR. DAVIS: Is that BNL study available? Did that turn out to be a NUREG report?

MR. SCARBROUGH: Yes. It was attached to a letter that went back to the BWR Owners Group, which is a public document so I don't think it was a NUREG. It was attached to a letter which was put in the PDR so it should be publicly available.

We can make sure you get a copy if you would like.

MR. DAVIS: I would appreciate that.

MR. CARROLL: What were the arguments in that situation? Why did the Owners Group believe that this was not an issue for BWRs?

MR. SCARBROUGH: There is a two-prong argument.

First, they considered that the original backfit analysis that the Staff did for Generic Letter 89-10 did not adequately address mispositioning, that it focused on actual failures of valves and the mispositioning was kind of an add-on so that was kind of a more legal argument. Their technical argument was that the redundancy in the boilers was such that there was a minimal or insignificant risk to public health and safety as a result of a mispositioning event because there was so much redundant system.

MR. CARROLL: And that same argument cannot be made for PWRs?

MR. SCARBROUGH: We are studying them right now. Brookhaven has done a study on them that Westinghouse Owners Group came in subsequent to the boiling water reactor request and asked for similar relief and there is a Brookhaven study ongoing right now which is complete and we are working on Supplement 7, which I will talk a little bit about, to try to address the results of that study.

[Slide.]

MR. SCARBROUGH: Next, just when everything was going well, we had Supplement 5, the MOV users group, commonly called MUG, developed a program to evaluate the accuracy of MOV diagnostic equipment. There was a significant amount of concern about the accuracy of equipment, particularly the spring pack displacement equipment, the equipment that relies on the movement of the torque fit spring pack to estimate thrust, which is a long way from the stem, but that's what the ITI-MOVATS equipment did.

As a result of that, the MUG group did some testing and asked vendors to come out to INEL and the office research supported INEL's equipment and manpower to help the MUG do this testing. And the MUG group produced a report which indicated that the equipment produced by IMPEL and

ITI-MOVATS which relied on spring pack displacement to estimate stem thrust did not meet the accuracy claims and it could be significant. It's 35 percent or so in some cases. So there was a significant error in that equipment.

We met with ITI-MOVATS in March '92, discussed the ITI-MOVATS validation program. They were developing an engineering report, 5.2, which would address that issue. NUMARC at that time also developed a guideline document to help licensees work through that.

So there was a significant amount of activity in early '92. Well then in later '92, the Liberty Technologies Group which produces equipment called VOTES, which measures the strain of the yoke and relates that to stem thrust, submitted a Part 21 notice which indicated that there was error based on possible improper use or assumptions regarding stem material constants and the failure to calculate for the torque effect when you are working in the threaded portion of the stem.

As a result of that, we issued information notice for that immediate concern.

In Supplement 5, we asked licensees to notify the Staff of their equipment and what their actions were being taken to address all this new information on accuracy of the diagnostic equipment. The licensees have all submitted their responses, we sent replies back, and during the generic letter 89-10 inspections, the inspectors asked about the status of that effort and looked for the implementation of the commitments that the licensees made in those letters.

For the most part, the licensees have addressed that, gone back and either to retest it or reanalyze a lot of the equipment that was set up, the MOVs that were set up with that MOVATS equipment or reanalyzed the VOTES data.

[Slide.]

MR. SCARBROUGH: Supplement 6 resulted from a public workshop we had, February '93, where we talked about the implementation of the generic letter and answered numerous questions from the public, from the licensees on the generic letter and the implementation. The primary part of Supplement 6 is the discussion of schedule extensions. There were a lot of requests about what does a licensee need to do to justify an extension to its 89-10 schedule.

In Supplement 6, we require a licensee of that plant to do that extension to submit certain information. And even though if the schedule is to be extended, licensees are expected to have MOVs set up using the best available data by their original completion date. So even though a plant may receive an extension for testing, the valves in the plant will be set up to the best available data, even though the testing may extend on beyond the original schedule.

So from our point of view, the main problems of MOVs should all be addressed by the five-year or three-item schedule. That was a key part of Supplement 6.

We have emphasized the licensees and it is emphasized right up front in that section of the generic letter. If the schedule is to be extended, the reporting requirements are they must tell us the completion status of the program and for each valve where the capability has not been verified by dynamic testing, either testing the valve directly or by some application of data from one valve to another, they have to provide us the valve-specific data and a capability measure such as an available valve factor or thrust capability, confirmation of the functionality using that best available information and the schedule for completing to testing and corrective action.

So we are currently reviewing a few. We have about five, I guess, in house right now requests for schedule extensions. We granted three or four over the past couple of months. But there hasn't been a deluge of extension requests. Most everyone is scheduled to complete this year or next year.

We also talked about the grouping of valves. One of the questions that came up was how do we accept grouping, what's the Staff's position on grouping. And in the original generic letter we said, test everything where practicable. However, there are lots of valves that you just cannot test. In a BWR plant, it is only practicable to test about 30 percent of their MOVs. In a PWR or pressurized water reactor, about 50 percent.

So even where you have the best intentions to test everything where practicable, you just can't do it in many cases. So we needed some guidance to the licensees on what would be an appropriate grouping methodology.

Some licensees like the Grand Gulf plant want to develop or have been developing a grouping methodology across the board for all their valves instead of the testing where practicable recommendation. So we needed some guidelines in that area for the Staff to consider and evaluate the acceptability of that grouping scheme.

MR. MICHELSON: Maybe it would be well to inform the Committee exactly what you mean by grouping.

MR. SCARBROUGH: Sure. Whenever you have valves of identical -- as identical as you can make them in terms of their size and their manufacture and their rating and things of that nature, their DP conditions, things like that, you can try to put them into a group or a family.

Then what you do, you decide -- you take a representative sample of those valves and test them under full DP conditions and then at that point you evaluate that information and then apply that data to the other valves and set them up in the same fashion. So that is a grouping.

MR. MICHELSON: That is not extrapolation, of course, then.

MR. SCARBROUGH: No.

MR. MICHELSON: You are requiring a member of each group, each size which is a group, to be tested?

MR. SCARBROUGH: Yes.

MR. MICHELSON: They have to do all of their threes, all of their sixes and all of their nines. They have to have one out of each of those at least?

MR. SCARBROUGH: Yes. It is a minimum of two per group or 30 percent. They have to do -- the guidelines are that they have to verify the design adequacy through analysis of industry and plant-specific data. They use data from a 30 percent sample and at least two of their valves per group.

MR. MICHELSON: Has your test program and results to date indicate that it is justifiable to consider a group of 20 or 30 valves and you pull two out and test them, that that will be representative of the performance of the 30?

MR. SCARBROUGH: They should be 30 percent.

MR. MICHELSON: You have to have 30 percent of the group?

MR. SCARBROUGH: Right.

MR. MICHELSON: A little better sample.

MR. CARROLL: Or at least two.

MR. LINDBLAD: Unless it is a unique valve.

MR. MICHELSON: From valve to valve, you've got galling problems and aging differences and a whole lot of things that are affecting it. But you can't test them all. It has got to have a reasonable program. This appears reasonable.

Thank you.

MR. SCARBROUGH: Okay, thank you.

And we try to get them to test the -- the highest priority valves, you know, get those tested so you have the most assurance on those. They need to validate all of their design basis assumptions. They need to consider all of the similarities and differences between the valves.

And then item 7 is very important. If the valve fails or shows inadvertent operation -- I'm sorry, improper operation, from the testing, you have to apply that information to all of the valves in the group.

MR. MICHELSON: One other clarification. The valves in a particular group might be performing break isolation functions, for instance. How many tests under those conditions must you have in deciding what the setup should be for the valves?

MR. SCARBROUGH: Those that have to isolate under breaks are not going to do it in the plant.

MR. MICHELSON: Obviously.

MR. SCARBROUGH: Those are purely impracticable to do. They need to obtain data. EPRI has been doing some testing of types of breaks and that data you can apply if you can find a valve that is applicable that EPRI has tested or EPRI also has a testing methodology.

MR. MICHELSON: With your approach, it looks like a valve from each of the groups has to be tested. If it is a break isolation valve, EPRI will have to test one from each of the groups to get some information with which to justify the rest of the group.

MR. SCARBROUGH: Right. Also what EPRI is trying to do is their methodology is to apply so that if you do not have a valve that looks identical to the one you have in the plant, the methodology is supposed to be bounding.

MR. MICHELSON: Are they trying to extrapolate from one size to another or just with any given size?

MR. SCARBROUGH: EPRI is trying to work it so they have different sizes and things of that nature. Their methodology is supposed to apply to your valve. to your size.

Now, Grand Gulf, their grouping methodology uses different sizes and we have concerns about that. They use a method that Siemens has developed over in Europe where they look internally at the valve and evaluate what the internal stresses are. So what their argument is, and we are still working with them on this, but their argument is that they can evaluate those differences even though the sizes of the valves are different by looking at the internal stresses. They break it down to a smaller scale. We are still working with them on that. They are still trying to convince us of that one.

MR. LINDBLAD: And when we are talking about MOVs, are we really talking about the lower valve structure? Are we talking about the valve and actuator?

MR. SCARBROUGH: Valve and actuator.

MR. LINDBLAD: Are we talking about valves in the as-designed, new, well-maintained condition or typical operating plant as-found conditions?

MR. SCARBROUGH: Both. In the plants themselves they are testing them in situ, as they have been there for years. So they are as-found.

The EPRI program has both. It has new valves that they have been using in plants and they obtained them from different sources. But also they have in situ data that they have collected from a number of plants and these are part of the methodology as well. They use them both.

MR. MICHELSON: For the break isolation tests, are they conditioning the valve before they test it? Or are they using it as received?

MR. SCARBROUGH: They are doing conditioning in terms of numerous stroking. One of the things that EPRI has found is that over-stroking when the valve is brand new, it has a very low thrust requirement. But as you stroke it just statically a number of times, maybe 100 times or so, you start to wear off that film and the thrust primer goes up and plateaux off.

MR. MICHELSON: They are conditioning the valves?

MR. SCARBROUGH: EPRI does that testing to reach that plateau. Other areas in Supplement 6, there is a whole enclosure that talks about a number of different aspects of the generic letter 89-10 program.

One is the use of PRA risk assessment. Basically it says, in Supplement 6, that PRAs are good for prioritizing your valves but not for eliminating valves from your program. All of the valves have to be evaluated. Safety-related valves, we talk about a report conducted or performed by KALSI Engineering, overthrust capability of the actuator. They have standard ratings for their actuators. There was a lot of interest in trying to raise that rate.

KALSI did testing on several different actuators from Limitorque and found that the thrust capability was higher -- overthrust capability, sort of stressed structural type of aspects are better than what Limitorque has said in their documentation and Limitorque has endorsed that. So they have raised the allowables on the actuators up because as they found so many valves need more thrust they have to raise their torque switches which you get a limit at the point of structural capability of your actuator.

The test acceptance criteria, that was one of the areas where we felt licensees needed more guidance in terms of what was appropriate for test acceptance criteria. And that, we provide that in Supplement 6.

For degraded voltage evaluations, one thing we found during 89-10 inspections is that everybody does their degraded voltage calculations differently and so we put in one way which -- one acceptable way which the Staff considered to be appropriate.

MR. MICHELSON: I imagine none of the licensees have a degraded voltage -- ability to apply degraded voltage. How do you justify that you really do know the performance at 80 percent voltage? What's the basis?

MR. SCARBROUGH: Actually, there have been some plants that -- the Wolf Creek plant does do degraded voltage, they lower their voltage down --

MR. MICHELSON: They do have an autotransformer or something --

MR. SCARBROUGH: They do the rheostat and lower it right down.

MR. MICHELSON: Okay, and what did they find when they did that? Any surprises or was it doing like they had -- EPRI thought it might?

MR. SCARBROUGH: Right. Now, they didn't. They found that, more or less, that it was producing what it should.

The Comanche Peak plant did a significant amount of testing on actuators looking at different voltage levels. And they found that it was about right, the output was about what you would expect. Which is interesting in the sense that the motor puts out a lot more than what the standard motor curve usually says. However, the actuator puts out -- in terms of its efficiencies are worse than what Limitorque predicts. So when you put them together it comes out about right.

MR. LINDBLAD: Were these all AC motors or some DC as well?

MR. SCARBROUGH: Some are DC as well.

And in pressure locking, thermal binding, that's an issue which has come to the forefront. AEOD produced a study and I will talk more about what we are doing in terms of a generic letter in that area. But in Supplement 6, we talk about some of the concerns regarding pressure locking and indicate that licensees -- there are regulatory requirements for determining that.

MR. MICHELSON: Did it surprise you that valves have a pressure locking and thermal binding problem? This has been known for 30 years.

MR. SCARBROUGH: No, it didn't surprise us.

MR. MICHELSON: And it shouldn't have been any surprise to anybody that you have to account for this. At one time, valve vendors used to even supply bleed-off taps and so forth on the bonnets. But they stopped doing it because I guess they began to think it was a nonproblem. But it's an old, established concern that you have to be -- you have to take into account when applying valves.

MR. SCARBROUGH: Right. It goes back to the mid-'60s, I think there was a --

MR. MICHELSON: It goes back at least that far. I go back that far.

MR. SCARBROUGH: Right. So it's an old problem. We have numerous information notices and during 89-10 inspections we were just finding licensees weren't addressing it. It just was something that -- a lot of times, their answer was they hadn't seen it at their plant so therefore it couldn't occur. And that wasn't appropriate because you may never see it until you need the valve.

[Slide.]

MR. DAVIS: Excuse me, Mr. Scarbrough. I think you said this applies to safety-related valves?

MR. SCARBROUGH: Yes, sir.

MR. DAVIS: I am wondering how you define that and what process was used to identify valves that were safety-related?

MR. SCARBROUGH: In the generic letter, we lay out the safety-related definition -- and bear with me a second.

MR. DAVIS: Let me just test you a little bit.

Does this include valves in, say, service water systems, component cooling water systems, auxiliary feedwater systems?

MR. SCARBROUGH: Only if they're classified safety-related per their FSAR.

MR. DAVIS: Oh, okay. It's not necessarily related to safety, but they are definition of safety-related?

MR. SCARBROUGH: Yes, sir. It's the kind of standard definition that you find in part 100. It's the protect against an accident. You know, protect against the release out to the public.

It's a relatively narrow scope. It's more narrow than the maintenance role. It's basically the safe-related, safety-grade, some people call them, but safety-related valves.

MR. DAVIS: Thank you.

MR. MICHELSON: You're supposed to go back to your design basis to find out. And that's when I began to realize going back to design basis wasn't always helpful because it wasn't clear in their -- two things you've got to worry about: Is it safety-related, and what are the requirements on it when performing a safety-related function?

And the requirements were pretty skimpy on many of these valves. The fact that it was safety-related was generally picked up, I think.

And if it's on the Q-list, for instance, it's safety-related.

MR. DAVIS: One of the more valuable insights we've gotten from all of our PRA work is systems that work and are not considered safety-related can become very important with respect to safety.

MR. MICHELSON: But that was not picked up here because it was not in the design basis. I think you've pretty well fallen back to design basis.

MR. SCARBROUGH: Exactly.

MR. MICHELSON: As the basis for saying it is safety-related.

MR. SCARBROUGH: The one area we went beyond design basis, and that was for the mispositioning valves that were like maintenance valves in safety-related systems that might be inadvertently changed position. At least for the boilers, they are still in the program -- I mean, I'm sorry. I mean, for PWRS -- boilers that were taken out.

But that's the only area that went beyond design basis.

MR. LINDBLAD: Mr. Scarbrough, let me go back a minute to the pressure locking that Karl was drawing attention to a minute ago.

Up until this past year, I would have thought pressure locking had something to do with the valve design itself, and the bonnet, and the like.

But, in this past year, there's been an episode in the plant on containment spray where a containment spray valve would not open from upstream pressure problems.

Is that a part of your definition of pressure locking? And is that what people are looking at?

MR. SCARBROUGH: Now, are you talking about the LaSalle? At LaSalle?

MR. LINDBLAD: It could well be that's the incident I'm talking about.

MR. SCARBROUGH: There was an event at LaSalle where they ended up having a pressure-locking event where the pressure -- the way these valve disk design for double disk or split wedge, they would relieve on one side and allow the pressure to enter into the bonnet.

And then, if you have pressure dropping on both sides, you now have pressure pushing out against the disks.

MR. LINDBLAD: Yes.

MR. SCARBROUGH: The valves are just not designed for that. They're only designed really for one disk.

You know, it's essentially doubling at least, and it could be even more if your temperature and your bonnet starts to increase and then go higher than that. So it's at least double.

And that's what we call pressure locking. Now what Carlisle was talking about was the vents and such. Some valves have them; many valves don't.

And that's where the concern lies. If that pressure does enter and build up, and then you have a drop on both sides, in some cases, you're just not going to be able to get the valves open.

MR. LINDBLAD: So you're saying that this recent surveillance test failure on a containment spray valve was because of that?

MR. SCARBROUGH: Yes. That's what LaSalle decided. Actually, it failed twice. It failed and they replaced a motor. And a couple of weeks later, it failed again.

MR. LINDBLAD: Okay.

MR. SCARBROUGH: At our public workshop we had in February of this year, Mark Dowd of Commonwealth Edison said that that valve failure has really concerned them. They have a very massive program to evaluate their valves at pressure-locking because of that event.

MR. MICHELSON: Earl, did you have something?

MR. BROWN: I'm Earl Brown. I'm with AEOD.

I think the event you're talking about on containment spray was at Waterford where a pump was started and a valve failed to operate.

That was a situation. It was not a motor-operated valve. It was an air-operated valve, for one thing. But, the situation was there was air in the system. This came about because of maintenance on a check valve.

And there was a significant increase in pressure over what the valve was designed to operate for. And it failed to operate.

But it was not an MOV. And it's a situation like it's a waterhammer like event that you got with a slug coming down. And this was trapped between the closed valve and an upstream check valve.

It was a wave that came down and the pressure increased and stayed high because of that situation.

MR. LINDBLAD: Fine, yes. You've refreshed my memory and that's what I was talking about. But, regardless of what the actuator was powered by, is that pressure-locking possibility considered in your valve program?

MR. SCARBROUGH: That is a new twist on it which, as we're developing the generic letter, we need to address in the generic letter, because it was a kind of a surprise to me that that --

MR. LINDBLAD: To me, as well, yes.

MR. SCARBROUGH: It kind of locked it up. And we've been working with Earl and AV on developing that in the generic letter.

MR. LINDBLAD: Okay.

MR. MICHELSON: They had good check valves, apparently. Good tight ones.

Laughter.]

MR. SCARBROUGH: The generic letter, itself, we developed a temporary instruction for the inspectors to evaluate the programs in the plants. The generic letter was rather unique in that it assigned the review process for the program to the regions, which is typically an NRR function.

Therefore, the T.I. had to be written in accord with sort of a special way. Part I involved a review of the program, itself, the development of the program. And the staff has conducted inspections of all the plants for part I, except for Millstone, which did a self-assessment, which we monitored.

And so all the part I inspections, all the program reviews, were all complete. There's some open items that need to be addressed. But, every plant has been inspected for that.

And the results of those part I inspections are summarized in information of this 92-17.

The part II of the T.I. involves the implementation inspections of the generic letter. And we've done about 30 of those so far. And we're still counting. We're doing them as we speak.

In April of last year, to provide more guidance for the inspections, there was a staff meeting, a management meeting, and a staff meeting to discuss guidance.

And approving that guidance.

And an April 30th memorandum, which is a rather thick document, provides a number of guidance tips to the regions in terms of the inspections. That was developed jointly between NRR and the regions, so they were on board with that document.

[Slide.]

MR. SCARBROUGH: Then, in June of last year, we went ahead and issued a revision to the T.I. so that we could implement or incorporate all of the results of the part I inspections, the workshops that we had among the inspectors, the management meeting that we had in April of that year. And we also referenced back to the April 30 memorandum and put that document in the PDR.

And Supplement 6 also provided guidance for the inspectors in that area.

And then, in 1995, which is about the time that T.I. expires, it's a two-year life, we intend to develop inspection procedure module that will address the entire MOV program.

So that's down the road.

[Slide.]

MR. MICHELSON: You have to monitor your time a little bit. We do have to finish by 10. We want to keep moving.

MR. SCARBROUGH: All right. That's fine.

The results of our inspection so far in terms of the scope, for the most part, we found it consistent with generic letter. They're identifying the valves that are safe-related. Most PWR licensees are deferring, mispositioning, awaiting the staff's review, and in completion of a proposed supplement that we're working on to address that for PWRs.

Design basis reviews, for the most part, we found that licensees are reviewing the appropriate documentation. In some cases, they weren't looking at all the parameters. Sometimes, they were ignoring flow. But they needed to make sure that the flow is at least reasonable in terms of a design basis to ensure that they have appropriate tests, or can use those results to reflect design basis capability.

We found a number of degraded voltage studies that needed updating. Licensees have been doing that over the past couple of years.

MR. LINDBLAD: What does that mean? Degraded voltage at the motor wasn't properly predicted, or that --

MR. SCARBROUGH: A lot of times, they didn't go down to that level where they would stop at the motor control center?

MR. LINDBLAD: Right.

MR. SCARBROUGH: They wouldn't go down --

MR. LINDBLAD: And so it was an electrical issue, not a system functional issue?

MR. SCARBROUGH: That's right. That's right. They just didn't have the information for us. A lot of times, it was just assumed to be 80 percent. But they hadn't checked it out yet. And they've been doing that.

MR. CARROLL: Back to the mispositioning issue, what did the staff want licensees to do about that?

MR. SCARBROUGH: What we wanted licensees to do is to assure that the valve would not be damaged if it was inadvertently operated. Or prevent that inadvertent operation.

So you could do one of two things. You could either size the torque switch settings so that it would trip early, or be able to complete that mispositioning stroke so that it wouldn't damage itself, wouldn' . burn out; or you could put in a feature in the control room to prevent that inadvertent operation. Key lock switches, or cover plates, or something to prevent the type of Davis Besse event where the guy just got in a hurry and just didn't think, and hit both buttons at the same time.

So there was two methods they could do with that.

MR. CARROLL: Smith cap spill.

MR. SCARBROUGH: -- that we talked about, the weakness we found in the pressure locking, the evaluation of the pressure locking in thermal binding.

In terms of the switch settings, some licensees were using updated valve factors. And a valve factor is just a simple way of equating the thrust requirement.

The old number was .3 where you multiplied a .3 times area of the disk times the difference of pressure. And then you add stem packing and rejection loads.

But that's the main component to get to your thrust. And we found that .3 was the old number which the vendors had used. And that old number, that old .3 was based on simple sliding friction in many cases of two pieces of metal sliding across each other, and it really didn't reflect what real life valves would do.

In some cases, licensees were updating their valve factors. Other ones were still using the .3. So we had some concerns in that area.

We saw that those assumptions for valve factor, stem friction coefficient, which is a measure of the friction between the stem nut, which how much torque from the actuator is converted into thrust, to move the valve up and down, that needed to be improved.

There were some simplistic assumptions there. And load sense of behavior, which is basically where under loaded conditions the torque switch may trip -- or will trip under the same torque that it tripped under a static or a no flow condition.

But, because of the interferences and the frictions and such, the thrust delivered by the actuator is less under dynamic conditions than under those static, no flow conditions.

So we call that rate of loading or load sense to behavior where that loss needs to be addressed.

MR. MICHELSON: Where are you addressing the valve tilt problem, the disk tilt problem?

MR. SCARBROUGH: The disk tilt in terms of -- that's in the valve factor assumption, where --

MR. MICHELSON: Yes. But, in order to have a feeling for what factor to use, you have to know the dimensions and the degree of tilt that can occur, and so forth.

How do you do that?

MR. SCARBROUGH: It's done in the gross fashion of when they do their dynamic testing, they back out the valve factor. And that valve factor will tell them what the net result was.

MR. MICHELSON: Well, this shows up as the break test, and they don't do that in the plant.

MR. SCARBROUGH: Well, when they do the testing, when EPRI has done the testing, or when licensee has done pump flow testing, they'll pick up that valve factor.

But, for blow-down type of conditions, they're going to need direct data where they've done blow-down.

MR. MICHELSON: The disk tilt that's apparently giving a great deal of a problem of having higher loads after you've backed off the seat, and so forth, and you had at the time you tried the breakaway.

And I was wondering how do people how what that tilt is for their valve, and so forth?

MR. SCARBROUGH: Now, what EPRI is doing, EPRI's program has blow-down data, and then they have valve factors or friction coefficients they backed out from that. The licensee, when they used EPRI methodology, may have used a bounding number, or they can go inside and measure a lot of those clearances and try to lessen that amount of bounding margin that they have to include.

MR. MICHELSON: Do you think that you can take a worst case tilt, so to speak, from the dimensioning that EPRI hash done, and use that --

MR. SCARBROUGH: Right, that's --

MR. MICHELSON: -- and use that as an assumption?

MR. SCARBROUGH: Right. And that's what they're doing because they worked out clean in valve factor, right.

MR. MICHELSON: That tilt angle is now in the calculation, isn't it?

MR. SCARBROUGH: No, it's not.

MR. MICHELSON: Not yet?

MR. SCARBROUGH: Not yet. They're still using the old --

MR. MICHELSON: They're using the old simple form.

MR. SCARBROUGH: Old, simple form.

MR. MICHELSON: Sort of like the --

MR. SCARBROUGH: That's right.

Okay. Let me go on to the next slide here.

[Slide.]

MR. SCARBROUGH: In terms of design basis testing, they found that many gate valves and some globe and butterflies required more thrust and torque to operate than produced by the vendors.

This I think has changed the minds of a lot of the licensees about the value of this program. I think they've been pretty shocked. I think they all thought that they'd find the old valve under a .3 valve factor. And they're finding much higher than that, all up to .8's and such, and in a few cases higher than that.

So they changed their own minds regarding the need to come up with some more appropriate valve factor numbers.

We have had some concerns with the lack of progress, with dynamic testing, weaknesses in the procedure and acceptance criteria, and lack of feedback of those test results.

But we've been emphasizing the licensee's need to do that. And I see some progress in that area.

In terms of other activities, needed improvement, justification for grouping, verification of extrapolation of the data because in some cases, or many cases, you can only reach maybe 60, 70 or 80 percent of your design basis difference of pressure.

And you need extrapolated information up to the design basis conditions.

A few licensees are doing multiple point tests at various different pressures, but most of them only really do one. And then they do a linear extrapolation.

And EPRI's looking at that and providing helpful guidance on that area. So they need to justify that.

More improvement in the valuation of anomalies and better involvement of the QA personnel.

Licensees need to pay more attention to regulatory requirements and tech spec requirements on reporting and responses with regard to the test results.

So those are some key areas of the testing

[Slide.]

MR. CARROLL: On the subject of testing, we have just, of course, completed our review of ABWR and System 80+.

Are you satisfied that those designs have provided testability to the maximum extent possible, or did you get involved in that at all?

MR. SCARBROUGH: One of the key areas of that is that we emphasize in those new designs that those valves have to be fully qualified before they are put in the plant, and I think that was the major weakness with the current plants out there.

So that is a key factor in all the documentation that we sent back to them, and looking at the testing processes and such, and then to have as much capability in-plant in situ to test as much flow as possible to periodically verify that capability.

So we have taken a lot of lessons learned from the current plants, and try to apply that to those new designs.

MR. MICHELSON: One of the lessons learned in the case of ABWR is that it really doesn't make any difference within reason how fast the valve closure might be. The problem is created in the plant while the valves are still trying to close. The problem being, of course, the adverse environment throughout secondary containment.

That throws a little different light than on other important aspects such as the environmental qualification of the powering to the valve, and the valve itself and so forth, which I think is outside of your problem --

MR. SCARBROUGH: Right.

MR. MICHELSON: -- but still important.

MR. CARROLL: I was thinking particularly of what I thought was a pretty clever combination of full flow testing in the 80+ design. They have done, it looks to me like, a good job there.

MR. SCARBROUGH: We were emphasizing the need for that so I am glad that they followed through.

In terms of the periodic verification and post maintenance testing aspects of generic letter, no utility had justified a method for periodic verification.

Calloway's, which is the first to complete its 89-10 program, does have a method, and I will talk a little bit about that in just a minute.

But most licensees were focusing on static testing alone with no dynamic at all, and we just did not feel that was going to be appropriate.

Post maintenance testing improvements, we have seen improvements in that area. Corrective action and trending --

MR. LINDBLAD: Maybe you will talk about maintenance later, but I am interested in the impact of maintenance done or not done, or done improperly on the existing as-found conditions.

When you say post-maintenance testing improvements, are people doing a pre-maintenance testing as well?

MR. SCARBROUGH: Typically, not a pre-maintenance. Now, they will do a --

MR. LINDBLAD: Can you really tell us if, in operation, the characteristics of the valve will change from completed maintenance until the next maintenance period?

MR. SCARBROUGH: One of the areas of 89-10 is that licensees develop margins that will accommodate degradation from one maintenance to another.

Now, for preventive maintenance, we have indicated licensees need to do some pre-maintenance testing because they need to evaluate how much degradation over time they had for, like, steam friction coefficients and things of that nature. So they are aware of the need to come up with a value for degradation.

MR. LINDBLAD: Can you characterize how much degradation there is in normal operation or non-operation?

MR. SCARBROUGH: Not -- I know licensees typically --

MR. LINDBLAD: Is there an aging effect, is what I am saying, on the valve?

MR. SCARBROUGH: It is interesting. From the data -- from the international meeting, Jerry Weidenhammer of the Office of Research has a study underway right now to look at that.

Their first study which came out just recently, their first results was based on -- I think it was like 18 months or a year. They took some samples and just did friction of a two pieces or metal, put it into a reactor or flow condition for a year or so and then raised it.

They had like a 200 percent increase in the friction, but that was from new to one year in.

They are going to do another after 18 more months and see what happens from this point to that point, so it should be interesting to see what happens over that time. But the pieces seem to be fitting together because EPRI found that new valves have a much better friction coefficient than if you stroke them a few times, and now research has found where if you have these two metals that are new, and you put them in a reactor for a year or so, they have increased friction. So the pieces seem to match. They seem to match.

But right now licensees are including -- the ones that have done this pre-maintenance type of testing -- 5 to 10 percent of margin for that degradation. But part of the periodic verification program is to ensure that that degradation does occur over time so that we don't end up losing the capability or the confidence in the capability of valves that we had a few years ago.

So that is kind of a key part that we are looking at right now. And there was a national meeting yesterday of NRR management in terms of how to go about ensuring that we maintain this confidence that we are gaining through 89-10, so we don't lose it five or ten years from now.

MR. LINDBLAD: Yes. Now, when you talk about a 5 or 10 percent allowance for degradation and surface, is that with the valve static or is that with the valve cycling?

MR. SCARBROUGH: It was cycling but static, under no-flow conditions. What we would call statically would be -- our nomenclature is static is no-flow, zero flow or zero DP.

MR. LINDBLAD: Excuse me. I meant always opened or always closed. Not operating, in other words. Not exercising the actuator during the operating period.

Earlier you said that new valves had to be preconditioned before they are tested because the surface performance is different from the brand new performance. That suggests to me that with every cycle of operation, somehow the valve performance changes.

So do you count months between maintenance or do you count operations before you need added additional maintenance?

MR. SCARBROUGH: Right now, licensees are counting months, like the 18 month PM, preventive maintenance frequency. But that may be something they get into later. This is a real new areas. We have spent, really, the last five years of our efforts just getting the valves qualified, and now we are into this next stage, but that's a good point because we haven't really talked -- most licensees just think about timeframe.

MR. MICHELSON: I would think they will find that's an indeterminant because depending on the nature of the corrosion occurring while it is in the static situation, the friction factor on the first cycle maybe quite different from the friction factor on the very next cycle done ten minutes later or whatever.

Oftentimes, the reason for maintenance is because you went and cycled the valve and it didn't work like you liked, so you decided to tear it down or whatever.

That measurement is not indicative. You know, it is hard to tell whether it is going to be more or less depending upon the corrosion product because the wiping occurs on that cycle; the next cycle see quite a bit different surface.

So it depends on what is happening and it works both way. I think even a lot of testing that was found, it works both ways.

MR. SCARBROUGH: That is true. Corrective action, we have emphasized a need to further improve that. Trending, the trending programs were all very brand new, and they just started getting into place. Training, we've seen significant improvements in training over the past five years. I have been very pleased with that. In terms of the schedule, we found some licensees had not made adequate progress.

[Slide.]

MR. SCARBROUGH: Let me briefly go through some of the examples of problems and causes. I will not go through all of these individual examples, but I want to focus on the causes and the overall types of problems.

In terms of design and qualification, one of the main problems is the underestimation of thrust and torque requirements. It is kind of a design qualification issue where valve friction for gate valves was underpredicted. There are a number of examples there where valves either failed during testing, and they found that the switch settings were too low or the actuators were undersized, or licensees found, based on the EPRI test data, that their valves might not work under the design basis conditions.

At Prairie Island -- you can see it as the fourth item there -- in September '93 reported that they had these Powell 8-inch and 10-inch skate valves which were seeing valve factors in the .49 and .93 range, which is quite a bit greater than the .3 which the valve vendor had indicated many years ago.

Then, most plants have not been doing as-found testing under 89-10 for design basis testing. That was a decision made back in 1989 that -- let's focus our energies on getting the valves fixed and not spend so much time testing them as found.

So a lot of licensees go in and do preventative maintenance, raise the torque switch settings, lubricate it, do everything they can to make it in the best possible condition and then they run the test.

Palo Verde was one plant which did not do that. They did as-found testing because they were curious how they would work as-found, and in November they submitted an LER which reported that a number of valves were questionable and might have been inoperable before the program. That is unusual for a plant to even have that information.

[Slide.]

MR. SCARBROUGH: On the next page --

MR. MICHELSON: I guess there is a message there, isn't there?

MR. LINDBLAD: Yes, that's what I was asking about earlier.

MR. MICHELSON: There is a message whether it was unusual or not. You must have thought it was unusual enough to look into it. And what is the agency doing about the fact that the real world of an accident sees the valves as found, not after being lubricated, tuned up and so forth, and then found to cooperate.

MR. SCARBROUGH: Exactly. That's the long-term program of 89-10, that they have to ensure --

MR. MICHELSON: The research or something?

MR. LINDBLAD: I think Pete is taking notes about it, so it will not show up on the PRAs.

MR. MICHELSON: A PRA does not know how to do any of this too well. PRA's use nominally loaded valve data collected over years on all kinds of situations, and not valves under duress.

MR. SCARBROUGH: Right.

MR. MICHELSON: Because we don't have much duress in a plant. That's what we call an accident, pipe breaks or something. Then we find out how well these things work.

MR. SCARBROUGH: That's right. In terms of some more examples, of these problems, I will not go through all of these. You can look at these in your leisure, but there have been a number of instances where the valve friction for the gate valves has been revealed to be underestimated.

[Slide.]

MR. SCARBROUGH: For globe valves, also. Everything kind of thought globe valves were all right. There was even a lot of effort to have us delete those from the 89-10 program back in early days, but we kind of kept them in there and we are glad we did because the EPRI program has found that some of the thrust requirements have been underestimated by the valve vendors as well. And Borg-Warner sent in a Part 21 this year on the sizing of their actuators for globe valves may be inadequate.

MR. LINDBLAD: Excuse me just a minute. You heading there speaks of valve friction and flow area. Have there been some surprises in the amounts of flow resistance in a globe valve or flow area?

MR. SCARBROUGH: What EPRI was finding was that when they use the standard disk area of the globe valve that their friction was being underestimated. There are a lot more thrust requirements than what would be predicted by using the difference or pressure and the area of the disk.

But what they found when they looked at it more closely was that in some cases the globe valves were controlled by the guide area as opposed to the disk area, so when EPRI plugged back in and used the guide area for these valves which showed the higher thrust requirements, it matched.

MR. LINDBLAD: Are you talking about the actuator loading or are you talking about the fluid resistance through the valve? I am worried about whether the valve will pass the flow.

MR. SCARBROUGH: I think we are talking about the fluid resistance through the flow -- through the valve because it is the thrust required to open or close that valve against that flow.

MR. LINDBLAD: I understand what your concern is. I am talking now from the fluid systems engineer's viewpoint. Were there any surprises on whether the valve itself will pass the flow.

MR. SCARBROUGH: I have not heard of it. I don't know if they have looked into that, but I have not heard. They have not reported that to us.

MR. LINDBLAD: Okay. Thank you.

MR. SCARBROUGH: We are having a meeting with them on June 28th and 29th. It is a public meeting. You are welcomed to have someone attend from ACRS if you would like.

In terms of steam friction coefficient, the old standard .15, which was used, didn't match. In some cases, a licensee had to go up to a .2 which seems like a small increase, but it is a significant amount in terms of the thrust requirement or torque requirement.

Also, for torque requirements for butterfly valves, EPRI has found mostly that the butterfly valves seem to match from their testing. However, there have been some problems with butterfly valves in the plants, valves failing to operate at Catawba, and then Byron found that some valves may not work properly.

So there is some concern for butterflies as well. That is kind of the next phase. Everybody is focused on gate valves, but butterfly valves also had their share of problems.

[Slide.]

MR. LINDBLAD: Did I understand earlier that your branch is divided in between motor operated people and air actuated people, and are the butterfly valve remarks you are making just limited to motor operated valves or do we see them on air piston operating valves as well?

MR. SCARBROUGH: We have been focusing on motor operated valves, but all this information is known to people in our branch that deal with air operated valves, so a valve is a valve. So I imagine information will have to be shared.

For differential pressure, there have been some underestimations of differential pressure over time, and we talked about that a little bit, overestimation of the motor output capability. We have had some concerns with design basis minimum voltage at the valves.

Motor brakes seemed to have had some problems. Either they do not hold well enough or they hold too much, so there is a lot of effort to take those out right now. So we had some events in that area.

[Slide.]

MR. SCARBROUGH: Other areas of degraded voltage concerns that have occurred, control voltage. In terms of 9-mile point, they had a concern where the starting contractor was not operating properly. They did not have enough volts for that. That was a different twist on that old degraded voltage problem.

Ambient temperature effects on motor output, as the motor heats up, its efficiency decreases and there is less output from the motor. Limitorque issued a Part 21 last May and they have -- licensees have been addressing that.

Load sensitive behavior, we talked about the output reduction over dynamic conditions, and that is being addressed to.

MR. MICHELSON: Just to keep all these various things in perspective, such as you find a particular valve is found to be inoperable, you have to ask how important is it.

To what extent does the Staff look -- going back now to really look as to how important some of these valves might be -- then again we take the example of reactor water clean up isolation, HPCI isolation and so forth.

If you break those high energy lines outside of containment, you've got a real problem. So when one of those valves fails to function, it ought to create a much higher level of excitement than when some of the other valves fail to operate which cannot result in the same kind of consequence.

Is somebody trying to develop an importance factor so you know which ones to worry about the minute you hear?

MR. SCARBROUGH: There is a lot of effort going on in the industry, NEI and the BWR interest group are looking at grading the different valves in terms of their priorities --

MR. MICHELSON: Now they are doing a PRA examination to try to determine the importance, but PRA doesn't reflect such things as the environment created in the building and so forth? It could, but the PRAs I have sen have not yet accounted for environmental coupling of components and the fact that you ruined the environment when the valve failed to function and, as a result, you have a problem, which is what happens when the reactor water clean-up lines break and the valves don't close. You ruin the environment and secondary containment.

Therefore, it has to be reflected in a PRA that shows how the engineered safety features are coming into play. That coupling is not in there. It could be, and that is the sorts of things that the agency ought to be thinking about.

MR. SCARBROUGH: Right. Our main concern is, by the time the program is over with, all their safety valves have to be set up adequately. If they have asked for an extension, then we get into the risk significance of those valves in particular. Like we would not expect them to ask for an extension for a reactor water clean-up valve. Those really need to be set up as early as possible.

Structural capability, we have found some problems with yoke cracking, motor pinion keys failing, a lot of this is a result of the higher thrust requirments that are imposed on the valves. Very recently a kind of a combination problem of roll pin in the torque switches, and there is an information notice that we are working on right now to alert licensees of that potential problem. Pressure locking thermal binding, we have talked about that, and that is the LaSalle event.

[Slide.]

MR. SCARBROUGH: Maintenance and training, I won't go through all of these, but --

MR. MICHELSON: How about the problems with lubrication wherein, if you don't lubricate it in the right way, or if you put too much grease in the spring, and so forth, then the valve won't work, how are you approaching that one?

MR. SCARBROUGH: A lot of that entraining and the maintenance to ensure that they have proper guidelines. I know Limitorque is putting out periodic technical updates, and maintenance updates in terms of just expressing to them how they need to make sure the valves are maintained properly. We alert licensees to these types of problems of maintenance and training type problems. There is a lot of feedback that we give them at the MUG meetings, and they have meetings themselves at these MUG meetings and committee meetings to talk about it.

MR. MICHELSON: If everybody is talking, then that is helpful.

MR. SCARBROUGH: So those are some of the areas there of problems.

[Slide.]

MR. SCARBROUGH: Then the last slide on problems, root cause and trending, that was an area that initially --

these are rather old events, but they really need to emphasize the need to determine the root cause and trend problems, and that has been a problem in the past with certain licensees.

MR. MICHELSON: The February '93 event at LaSalle on the RCIC steam line, can you tell me a little more about it?

MR. SCARBROUGH: What happened there was, on February 10th, the motor failed -- the valve failed to open and burned out the motor. I am not sure what they remember. I don't know if they called it a bad motor, or something, that is kind of a standard cause. So they replaced the motor and, two weeks later, on the 26th, the same thing happened, the same situation, it burned out again.

So they really didn't take a very careful look at what the root cause was on February 10th. Then on the 26th, when they had it again, they said, well maybe our root cause was wrong, and they went back and reassessed it. So this was emphasizing a need to really make sure you have nailed down the root cause.

MR. MICHELSON: What did they finally determine their root cause was?

MR. SCARBROUGH: Pressure locking.

MR. MICHELSON: I beg your pardon?

MR. SCARBROUGH: Pressure locking.

MR. LINDBLAD: Was the second test a surveillance test or was it required by operation?

MR. SCARBROUGH: You know, I don't remember. I don't remember on that.

MR. LINDBLAD: If it was RCIC, it sounds like it would have been.

MR. SCARBROUGH: Do you know what the second one was? I know the first one was surveillance. I don't remember it, I am sorry.

MR. LINDBLAD: But it was good they did the surveillance test to find out?

MR. SCARBROUGH: Right, or it wouldn't have worked when they needed it.

[Slide.]

MR. SCARBROUGH: We talked a little bit about the mispositioning. This is the proposed Supplement 7 that we are working on. The Brookhaven study is in. We have been working on preparing the supplement to determine the need for PWR plans to address mispositioning. We met with CRGR on May 10th. They had several questions and comments, and we have been working to resolve those. So we haven't really nailed that down. But we hope to have something out in the next month or so.

MR. CARROLL: Carl, why is it that we are not looking at these various supplements to the generic letter?

MR. MICHELSON: The committee hasn't indicated, at least to me, any dire compelling desire to see them. We have discussed them in our mechanical components subcommittee meeting, but we don't hold them very often any more because, basically, I think the feeling the part of at least myself and some of the other members was that it is an issue that was important at the time the subcommittee pushed it. It appears that it is being resolved, everything is going fine, and we find better things to do with our time.

I still have basically that feeling but once and a while we like to get it refreshed by hearing all the stuff that is going on.

MR. CARROLL: Are you looking at these?

MR. MICHELSON: I have copies of all the supplements.

MR. CARROLL: Are you looking at --

MR. MICHELSON: I don't have 7.

MR. LINDBLAD: Are you getting them contemporaneously?

MR. MICHELSON: Well, when Igne was here, he used to bring them to my attention because he would get them, whoever takes his place will do the same, I am sure.

MR. CARROLL: Al was getting them to you as they were being reviewed.

MR. MICHELSON: Yes, because he had a lot of interest. We have had a lot of communication with Tom and the others, we keep close to it, but not in terms of asking the committee to spend a lot of time on it.

Of course, if the committee is really interested, there is a lot of things we can talk about in this area. There are still a lot of unanswered questions that people are working on now, and it depends on the degree to which you want to follow it.

MR. SCARBROUGH: Let me talk a little bit about pressure lock, and I won't go through all this background here, but basically there was an AEOD study. We started to look at it, we had our public workshop in February of this year, and then we have started to develop this generic letter which will ask licensees to address power-operated valves, not only motor-operated valves but power-operated valves, air-operated, whatever type of valve that would be under a pressure locking type of situation would need to be addressed. So those are the areas that we are talking about.

I want to save some time and I am running out of time, I want to talk a little bit about the international meeting that we had.

MR. MICHELSON: Maybe before we get to that for just a moment, I would like to hear from you a summary statement as to the level of industry interest and cooperation on this program. I have sensed in the past that the industry is all aboard and has not been resisting, is that kind of still the case?

MR. SCARBROUGH: Yes. We met every year, or we have in the past three or four years with the BWR owners group in June, and we meet again with them on June 24th. Last year, during their presentation, they indicated that Generic Letter 89-10 has been worthwhile because of all the problems it has developed, and that is quite a change from 1989.

We present to the MUG group at their meetings all our activities. They try to relate to us what they are doing. They get us involved in that. The industry is very interested in this periodic verification aspects. Some of the O&M committee members want to take a more lead role in that to develop an appropriate long-term aging type of program for monitoring degradation, and we are anxious for them to take a role in that.

MR. MICHELSON: It would appear to me that the rest of the users of valves in this country or the world ought to be very much interested in the program because they finally are learning how the valves really work.

MR. SCARBROUGH: Yes, there is.

MR. LINDBLAD: I would like to pursue that. I gathered from what you said that you translated industry to mean licensees. How about the actuator vendors? There was a period of time where the actuator vendor had a very large share of all the actuator business, but nuclear was a small part of that, and he didn't seem to enjoy all the attention he was getting in that regard.

MR. SCARBROUGH: Yes, I think that is probably still the case because there is even more attention now. They don't turn -- the actuator vendor doesn't turn information around probably as fast as we would like but then, again, they have to make a careful decision before they put out information, but about every six months they will put out a technical update or maintenance update of different things that have come up. They meet with the MUG every meeting and have an hour discussion of all the questions that come up and they are very forthright in their answers. I don't think they enjoy being in that spotlight, but they do stand up there and answer those questions.

MR. LINDBLAD: So the situation has improved as time goes on?

MR. SCARBROUGH: Yes, I think so.

MR. LINDBLAD: Thank you.

MR. SCARBROUGH: The program status, Generic Letter 89-10, Callaway is complete. Their periodic verification program that they are proposing is that they do dynamic testing, a sampling at the next outage, and develop an amount of margin that they need to account for that degradation, and they are going to submit information after the next outage to support that margin that they are developing.

Fort Calhoun and Comanche Peak are ready for close-out and several others are approaching. I estimate about 70 units will be done in the next 18 months in terms of their current schedules. Then we will have maybe 25 or so left to deal with after that.

MR. DAVIS: Excuse me. Are RHR valves covered under this program?

MR. SCARBROUGH: Yes. If they are safety-related, right.

MR. DAVIS: One of the things that we see happening at some BWRs is, a void collapse in the system during shutdown causes a pressure surge which calls for isolation of the RHR system, so the valves close and then have to be reopened to reestablish the cooling. This happened at Cooper recently, and we are going to hear about that later this morning. This program covers that kind of an event?

MR. SCARBROUGH: They are supposed to cover normal operations, abnormal events, and accident type conditions.

MR. DAVIS: And shutdown.

MR. SCARBROUGH: Well, it depends on if they are a cold shutdown plant or a hot shutdown plant.

MR. MICHELSON: I don't think I can agree. You are not covering water hammer in this examination so far, are you?

MR. SCARBROUGH: Not water hammer.

MR. DAVIS: Water hammer I don't think will affect the valves.

MR. MICHELSON: No, but that is part of that RHR isolation.

MR. DAVIS: It causes the isolation, yes.

MR. MICHELSON: I think it is beyond the study and verification that is done here. This program confirms that if you have a closed valve it will open, or if you have an open valve it will close under normal or predicted dynamic conditions, but not unpredicted. It is not in there. That was an unpredicted event, I thought.

MR. DAVIS: But it has happened. It is certainly not an isolated incident.

MR. MICHELSON: I can give you a litany of things that this program doesn't cover that can happen, but this is an order of magnitude better situation than a few years ago just for where we are today, but it doesn't cover everything. It wasn't intended to cover anything of that sort.

MR. SCARBROUGH: Right, you just can't cover it.

In terms of the meeting we had in April over in Paris, the IAEA and NEA, Nuclear Energy Agency, coordinated this meeting of MOV specialists, and there were over 100 participants. We had countries represented, Belgium, Canada, Czech, Finland, France, Germany, Hungary, on and on going down to the United Kingdom and the U.S. There were five different sections on regulatory activities, operating experience, MOV improvement programs, research and development and testing and maintenance. Then also on the last day we also toured the EDF testing facility outside of Paris which was quite impressive.

Some of the highlights were that everybody had valve problems. The continue to incur around the world, and there was a tremendous interest in what problems other people had seen and what are people doing about it.

The regulatory authorities in various countries, Belgium, France, Germany, Spain, Sweden, the United Kingdom and us, and the U.S., have requested licensees to do verification activities of the valve's capability. In the U.S. it is Generic Letter 89-10. In Spain for the U.S. designed plants in Spain, they have to follow 89-10. France has a different type of program, but it is like Generic Letter 89-10, and Germany as well. So a lot of countries have programs similar to ours ongoing.

The French activities were very interesting because we weren't even aware that they were doing all of this on motor-operated valves. They have had a massive program underway. A few years ago they had a failure which --

MR. LINDBLAD: Excuse me, Mr. Scarbrough, as you are talking about these activities, are you talking about activities of regulators or activities of the plant operators?

MR. SCARBROUGH: Actually both. The regulators have requested licensees over at their plants to perform DP testing, to reevaluate their valves for capability.

MR. LINDBLAD: So it is both.

MR. SCARBROUGH: It is both, yes.

MR. LINDBLAD: Thank you.

MR. SCARBROUGH: The French had a program to do a number of testing of valves in their plants and they found several valves that they consider to be inoperable in all their 1,300 megawatt units and their safety injection systems, and their answer was that it was very fortuitous that they discovered this at the time.

In terms of pressure locking, France and Germany are really head of us in terms of addressing pressure locking. The French are installing release in their valves which could be susceptible, and the Germans have done that many years ago. At our public workshop on this, the speaker from Germany was surprised that we were still looking at it after all this time.

MR. LINDBLAD: You will remember Carl was surprised, too.

MR. SCARBROUGH: So that is something that we found that the French are ahead of us in that area. The discussion of research activities focused on the U.S., but the French have done quite a bit of testing, the Germans as well, and in the United Kingdom, just in the Sizewell plant, all of their plants in Sizewell will have to be tested under as much flow as possible as part of the start-up process for the Sizewell plant, so they are developing quite a bit of information there as well.

Everyone seems to be increasing the use of diagnostic systems. The Japanese talked about their systems that they are developing. It appears as though the U.S. is probably ahead of the other countries in terms of the sophistication of the diagnostic equipment, but there is a lot of effort to improve that elsewhere.

There was quite a bit of discussion of the need for improvement in the maintenance and periodic testing of valves, and everyone recognized we needed this improvement, but no one really had a standard best method that everyone would agree to. But there was as strong consensus that that was needed and that was an area of maybe future work.

MR. MICHELSON: This was the first international meeting of this sort that has been held on the valves.

MR. SCARBROUGH: Yes, of this magnitude. We have met with the British before and the Germans.

MR. MICHELSON: I mean the bringing together of a large number of experts in the variety of countries in one location to talk about it. This was, I think, the first time.

MR. SCARBROUGH: Yes, sir, it was the very first time. I think everyone was surprised. I know talking to the coordinators from NEA, they were very surprised that there was this massive interest out there which they had not been aware of. Efforts are being made to focus on the most safety-related valves. Everyone agreed, we needed to focus on those, but only in the U.S. is there an ongoing regulatory and industry evaluation program to look at risk based methods. For everyone else, it was more kind of hit and miss.

The conclusions I drew were MOV equipment may be different in the various plants. A torque switch may be here rather than here and things of that nature, but they all work basically the same way. And the problems and approaches to resolving those problems are all very similar at all the plant -- all the countries, even if it is not a U.S. designed type plant. So there was a lot of interest in that to continue to meet.

And NEA said at the end of the meeting that they would reconvene another meeting in a couple of years to see where we are and how we have developed this kind of periodic verification program. So there was a lot of interest to continue it as well.

We consider it to be a very successful meeting.

MR. MICHELSON: We have copies of all the papers from the meeting. I don't know who is -- you are the custodian of them now? And how many -- did all members get those or just some?

Any member who wants -- I found the papers to be very good. By and large they were very good. The depth of quality was varying a little, but they all were working on the right -- seemed to be working on the right kinds of problems.

MR. SCARBROUGH: Right. And the language was English. Everyone spoke in English, which was quite difficult for some of the members. But there was very good communication among all of the participants.

MR. CARROLL: The French permitted that.

MR. SCARBROUGH: Yes, that was a shock.

[Laughter.]

MR. MICHELSON: It wasn't really their meeting so they did not dictate the language.

MR. SCARBROUGH: Many of the gentlemen spoke English better than I did, so it worked out quite well.

In terms of EPRI, very quickly in my last two minutes, I want to let you know where EPRI is on its program. They have conducted -- most -- I think all of their testing basically is done, in terms of the flow loops and the gathering of the data from the plants. They are evaluating their test data right now. They have found many of the thrust requirements to be unpredicted. They -- we prepared an information notice, 93-88, which gave the status of the program and many licensees are starting to implement that data.

Commonwealth Edison just recently declared several valves inoperable based on that data alone. So there was a tremendous recognition that the data is very important among the licensees.

MR. LINDBLAD: When a valve vendor under-predicts the thrust required to operate the valve, does that only affect the actuator or does he have to go back and change the stem?

MR. SCARBROUGH: Usually, it would only affect the actuator itself.

MR. LINDBLAD: You spoke of some very large factors on some locations. Have any stems had to be changed for --

MR. SCARBROUGH: Some stems, some actuators, some internal parts of the actuators. There has been a --

MR. LINDBLAD: I'm talking about the valve now, the valve stem not the actuator stem.

MR. SCARBROUGH: Well, they're connected. Yes. There's quite a bit of modification --

MR. MICHELSON: Are they getting to where the bolting is no longer adequate? I've seen operators in the past tear the bolting right out because they are a little too hefty.

MR. SCARBROUGH: They do have to evaluate the bolting --

MR. MICHELSON: If you keep pushing them up, you're going to stress a new point and you wonder about pulling the bonnet off.

MR. SCARBROUGH: That's right. And all those weak links have to be addressed.

We're -- licensees have identified the immediate problems and we are meeting with the -- EPRI has submitted the top of the report, or at least the initial phase of it, and we are starting to review all of the reports that EPRI has prepared and we are meeting with -- meet with EPRI --

MR. MICHELSON: Are those available to the public yet or just to you?

MR. SCARBROUGH: They are submitted to, I guess, NRC but I don't see why they wouldn't be public documents.

MR. MICHELSON: We could get a copy of the EPRI reports.

MR. SCARBROUGH: We will check on that and see if there are any -- what the proprietary -- a lot of them are going to be proprietary so there would be that protection involved.

MR. MICHELSON: We can handle them with proprietary all right. I just wondered how widespread they were being disseminated so far.

[Slide.]

MR. SCARBROUGH: There are current activities. I think I kind of mentioned a lot of these as we kind of went along. Our Part 2 inspections, reviewing the closeout for those licensees that have completed their programs, reviewing schedule extensions, study mispositioning, the pressure locking, the top of the report from EPRI and the symposium that we are having July 18 to 21st here in Washington with ASME. If you all haven't heard about it, it's going to be a very good meeting. We have them about every other year and I think this one looks probably the best of all of them.

MR. MICHELSON: That's going to be held where?

MR. SCARBROUGH: The Hyatt Regency downtown. And you all should have received a brochure.

MR. MICHELSON: We have not seen the notice on it.

MR. SCARBROUGH: We will get brochures.

MR. MICHELSON: I have got another appointment at that time. I think we will dispense with the check valve discussion and move that on as an agenda item for some future meeting.

MR. SCARBROUGH: That's fine.

MR. MICHELSON: It is wrought with some of the same kinds of interesting things and it could precipitate a lot of good discussion. But with that, we will see if there are any final questions.

MR. CARROLL: I have an observation. MOVs or valves or power-operated valves or whatever we want to call these has turned into quite a can of worms. Thermo-Lag has turned into quite a can of worms.

Here are two examples of where the utilities and their AEs have taken at face value information that was provided by the suppliers of equipment.

Is anybody looking at other areas in the design of our operating nuclear power plants where these same things may -- same trap may have been fallen into? That is not very good English, is it?

[Laughter.]

MR. MICHELSON: Does anyone want to volunteer an answer?

MR. LINDBLAD: Mr. Carroll and I have the same background in the same industry and one of the characteristics of civilian power plant design and construction is that it has been weak in qualification testing of components whereas when we talk about some of the other large engineering projects in the world, when we talk about aircraft or space vehicles or things like that, extensive qualification testing of components goes on before they are incorporated into designs.

I believe the steam power plant business, which is at the roots of the nuclear industry believes that since it was formed in 1910 or something early like that, all of this plant experience has built up a volume of experience that does not require qualification testing in these components. But the point is well taken. I believe it is one of the things that we have to be alert to and aware of and as we look at particular components of where should they be qualified by test.

MR. CARROLL: I guess the point I was making, should there be some proactive effort to ask the question, are there other places --

MR. MICHELSON: Do you want to look around and see where else the bones are buried?

MR. LINDBLAD: Both of these systems we are talking about are purchased to what is called voluntary national standards. And say requirements and the like that basically impose on the vendors the responsibility to qualify their component to some standard and the credibility of the vendor is usually what is at stake.

MR. MICHELSON: It is usually our unique application that brings out the shortcomings which are otherwise not known or noticed.

MR. LINDBLAD: Either that or a lack of the designer's understanding that there may be weakness in the national standard.

MR. MICHELSON: I ran into that a little bit on refrigeration systems which, because of the unique characteristics of what we demand from that refrigeration system, especially in terms of accident reloadings and all this sort of thing, this is not an application that other people worry about. But we probably should be very worried about it, at least to make sure that we thoroughly understand it.

MR. CARROLL: That is why we hopefully have the Staff's attention.

MR. MICHELSON: They have been purported to be writing a standard review plan for years now and never wrote it, so I don't know how much attention we really got.

MR. CARROLL: Marty Virgilio seems to want to have a say on all of this.

MR. VIRGILIO: Back for the third day in a row, this is Marty Virgilio from the NRC Staff.

As a result of Thermo-Lag issues and also as a result of the EQ issues that came up when we were going back and looking at plant life extension, the Staff has undertaken now and has just begun a systematic effort to go back and look at those situations and programs that have attributes similar to what we wound up with on Thermo-Lag, these test programs and EQ test programs, where there may be some concern or some opportunity where we let something go by without thoroughly and exhaustively looking back at how it was qualified.

So the first step is to look at where has the Staff evaluated or accepted programs or situations or qualifications that have these kinds of attributes. Then I think we are going to go back and systematically evaluate like we are currently going back through the EQ program, the adequacy of previous decisions.

Now, that is currently covered under our fire protection task action plan. I don't know if we briefed you on that, but I know we quarterly provide updates of that plan to the Commission and send you copies.

MR. MICHELSON: I think the subcommittee said they would get to that in a subsequent meeting.

MR. LINDBLAD: Mr. Scarbrough, I have one other --

you have given us a number of anecdotes of valve maloperation. Is there a systematic approach to convert some of this to both good and bad experience into PRA numbers?

MR. SCARBROUGH: There have been discussions of that. I think what the decision was made, rather than trying to do it in midstream while 89-10 was undergoing, wait until the program is over with in the next year or so and then go back and reassess whether or not any basic number changes need to be made to the PRAs. But we have thought about that but we had thought, well, try not to do it in midstream but let's wait until we finish and then reassess it.

MR. LINDBLAD: And you are only talking about the bad performance, not the good performance?

MR. SCARBROUGH: Right. We see quite a bit of improvement in the performance based on the 89-10 program.

MR. MICHELSON: Any other questions?

MR. DAVIS: I want to follow up on Bill's question. PRAs generally, or a lot of them at least, have looked at the sensitivity of valve failure rates to the core damage frequency and have ranged the failure rate over a rather wide range.

MR. MICHELSON: What they have not done is look at the consequence if it were to fail in terms of environmental changes that then feed back. That is where they break off. They just fail it and say, we lost that function and now how many functions do we have left.

MR. DAVIS: That is covered partly in other sensitivity studies where higher failure rates are used for any number of systems. A lot of the sensitivity studies have been done.

MR. MICHELSON: Thank you very much, Tom for your very good presentation, very detailed. I think for committee purposes, though, we need to think about where we want to go from here in terms of increase or decrease in activity.

You need to get a new subcommittee chairman one of these days to carry on with the mechanical components. I think there are a number of things we can discuss when you discuss your long-range plan that need to be thought about.

MR. DAVIS: There is no letter on this?

MR. MICHELSON: No, no. This was information only, just for your enjoyment. I thought it was quite good.

MR. CARROLL: I thought Tom did an excellent job of summarizing a lot of material there.

MR. MICHELSON: I asked him to do this because we keep getting new members and we really need to be brought up to speed.

MR. KRESS: At this point, we are at the agenda item called Operating Experience. We are scheduled for a break at 10:30.

MR. CARROLL: Would it be better to take our break now?

MR. KRESS: That's the subject I was going to bring up. What do you think?

Let's do that. Let's take a 15-minute break at this point and be back at 10:25.

[Recess.]

MR. KRESS: The meeting will please come back to order.

Jay, this is your issue. I will turn the floor over to you.

MR. CARROLL: Okay.

This is one of our periodic briefings on operating events and the two events we're going to hear about today are the event at Cooper involving loss of shutdown cooling and I guess it has happened elsewhere. And the event at Sequoyah with the famous gas bubble.

With that, I will turn it over to Al Chaffee and I will look to you to play ringmaster and make sure that we get both of the events well covered in the hour and 35 minutes we have.

MR. CHAFFEE: We have some people here to help us do that. For the first discussion on the Cooper event and some other related BWR events, the main speaker is going to be Neal Hunemuller from the Events Assessment Branch. We also have with us the senior resident inspector, Ron Kopriva. And also I understand that the licensee is here and I was told the licensee manager, Greg Smith, was going to be present so also perhaps he will be able to help us as well. And also there are some other folks from NRR as well within the projects organization.

For the Sequoyah briefing, the main speaker will be Dave LaBarge who is the project manager for Sequoyah. We also have some of his management here as well as we have -- we are fortunate to have from the region Scott Schaeffer, who is a resident, and Mark Lesser, who is a section chief. Also, Brian Grimes, my division director, is here and Marty Virgilio from the technical side of NRR, who is the division director, as you know, systems safety and analysis.

So with all these folks hopefully we will be able to answer most of your questions.

So at this time, I will turn it over to Neal Hunemuller.

[Pause.]

MR. CARROLL: Before you get started, Neal, yo can tell us a little bit about your background, what makes you smart enough to be in the Events Assessment Branch.

MR. HUNEMULLER: Certainly. My name is Neal

Hunemuller. I am with the Events Assessment Branch. I am a Senior Operation Engineer. Back about a year or so ago in February, I joined the Events Assessment Branch. I was previously in the Operator Licensing Branch as a BWR Examiner in charge of their efforts on fitness for duty program and simulator certifications.

Prior to that, I had worked for Dwayne Arnold as a Senior Reactor Operator, STA and Design Engineer. I was with them for about six years and before that I had worked for General Electric for about two years as a nuclear engineer in Design.

[Slide.]

MR. HUNEMULLER: Starting in on this first event, I do want to emphasize that this is not just a Cooper event, although that is the first one we are going to talk about. There are several other events that will be discussed.

We call it loss of shutdown cooling due to pressure transients. Pressure transients in this case, we are talking about water hammer and clearing of air voids really, so it is not pressure transients in terms of normal pressure transients.

[Slide.]

MR. HUNEMULLER: All of these events involve loss of shutdown cooling caused by short durations or short pressure transients and their result in short duration losses or shutdown cooling.

None of these events have involved a long-term loss of RHR or shutdown cooling. All of these events that I have been talking about were due either to clearing or collapse of air or steam vapor voids.

What happens when they clear, as you get a -- there are pressure switches on the low pressure suction piping of the RHR system that actuate a relatively low pressure, usually 75 to 100 pounds to protect this low piping from reactor piping -- reactor pressure piping that may be at operating pressure.

And the shutdown cooling piping is, in the Cooper case, 150 pounds. At some plants it is higher, maybe up to 600 pounds.

MR. LINDBLAD: And these pressure switches, what kind of time constants do they have? Are they Bordon tubes or are they transmitter type Barton cells?

But in any case they have a fast response?

MR. HUNEMULLER: Fast responding.

MR. LINDBLAD: Even though it may not be required that they be fast responding?

MR. HUNEMULLER: That's correct.

MR. LINDBLAD: Okay. Thank you.

MR. HUNEMULLER: And, in fact, that is something I will bring up as a possible solution that that one licensee is looking at.

[Slide.]

MR. HUNEMULLER: I will move on now to the Cooper event. I think I will go ahead and use the other slide projector to show a couple of figures.

That is a figure of the RHR system at Cooper.

MR. CARROLL: We have that in our package someplace after page 9.

MR. HUNEMULLER: Yes, I believe that is true.

This Cooper event occurred on March 17th of this year. The plant loss shutdown cooling for 13 minutes in this case. During that time temperature increased about 5 degrees, and when it happened the vessel level decreased 7 inches.

MR. DAVIS: What caused that?

MR. HUNEMULLER: The level decrease in this case is due to avoid collapse, and the water from the vessel taking that volume.

MR. DAVIS: Thank you.

MR. HUNEMULLER: In this case, shutdown cooling had been initiated two and one-half hours earlier. The head vents had been opened 44 minutes earlier when they believe temperature had been reduced below 200 degrees according to their indications.

MR. CARROLL: So they were in the process of shutting down?

MR. HUNEMULLER: Yes, and, in fact, had established shutdown cooling in this case. That does make this event somewhat different from the events I am going to talk about after the Cooper event.

In this case, they believe the collapse of the void in the RHR reactor recirc piping was the most probable cause.

MR. CARROLL: Void is a steam void?

MR. HUNEMULLER: In this case, it is a steam void, yes. In all of these events they are not necessarily steam voids, they may be air pockets, especially in instrumentation. But I will come to that on the other events.

MR. CARROLL: So that suggests that someplace in the RHR system we had temperatures quite a bit higher than those existing in the vessel?

MR. HUNEMULLER: Right. They established shutdown cooling as they are depressurizing when the inner lock on these pressure switches clear. Then they continue reactors depressurization. If a section of this piping has trapped hot water as they continue to depressurize, it can vaporize and you don't really know when that is going to clear. That is really what happened in this case.

This drawing actually shows the line up that

Cooper was in in this case. Coming off the recirc A loop is the shutdown cooling suction line through valves 18 and 17. Through their 15 valves to the B RHR side. In this case, the D pump was running. It comes through there and through the heat exchanger and through this 12 valve.

The little T's indicate that these valves may be throttled to establish their cool down rate. In their case, administrative, 90 degrees fahrenheit per hour. Right up through there to the LPCI injection valves, 27 and 25 in this case, and then into the discharge of the B recirc pump with its discharge valve closed. The A side s actually shown in the condition that they were in in all these.

Their LPCI injection valves both closed. These other valves closed. The system was actually being prepared for maintenance on the 27 valve, I believe.

MR. LINDBLAD: What is the relative elevation of RHR to the reactor vessel? Is the RHR system low in the structure? Is there submergence on that RHR?

MR. HUNEMULLER: Depending on which section you are taking about because it is connected to so many things.

MR. LINDBLAD: So it is distributed throughout the building?

MR. HUNEMULLER: Right.

MR. LINDBLAD: Thank you.

MR. CARROLL: But the lowest equipment in that system is quite a number of feet below the bottom of the reactor vessel?

MR. HUNEMULLER: Yes. I am going to switch to the other drawing that is in your package. This was a composite drawing provided to us at our request following this event.

This may come back to the question of where a void might have been formed. The licensee believes the void was formed at this location, which is in the A side LPCI injection piping after the two closed valves that we showed on the other drawing where it taps into the A recirc pump discharge.

This piping is 24-inch diameter piping. This is a relatively high elevation horizontal piping location, so that is one of the reasons they think it was susceptible to the void formation.

MR. MICHELSON: Are they true isometric or a schematic isometric? Do you understand what I am asking? A true isometric is the real isometric drawing depicting the exact elevations and everything, every single loop, every single bend is in a true isometric.

Schematic isometrics are just kind of three-dimensional cartoons. I think that is all this is.

MR. HUNEMULLER: That's all this is.

MR. MICHELSON: You will find a lot of places for air pocket formation and so forth if you look at a true isometric as opposed to a cartoon.

MR. HUNEMULLER: The licensee developed this from those true isometric drawings.

MR. DAVIS: I hope the pipe doesn't really look like that.

MR. HUNEMULLER: No. This is to help get it onto the composite drawing.

MR. MICHELSON: It has no elevation, which is very important in understanding where air might pocket. This is almost a useless drawing to analyze from. Almost useless.

MR. CARROLL: The elevations have some realism to them, don't they?

MR. MICHELSON: But not the scale.

MR. HUNEMULLER: Well, I would hate to put any real analysis into using this drawing. Like I said, I would not use this drawing for analysis.

MR. MICHELSON: That's for sure.

MR. HUNEMULLER: I think it is pretty good for illustration.

MR. CARROLL: Especially for us.

MR. HUNEMULLER: The other thing this shows is the recirc A loop shutdown cooling off of the A loop going off to the shutdown cooling suction valves and then off to the B loop.

Then this is the continuation of the recirc piping. This recirc pump A was running. This is what we showed on the other drawing, that these valves were open and that pump was running.

These are the pressure switches that pick up on the 75 pound isolation, the shutdown cooling suction pressure isolation.

The reason they think this was the location, there are several reasons, actually. Number 1, it is in this relatively stagnant section of piping, a relatively high elevation horizontal. That section of piping had the adequate volume required to meet with the observed level decrease.

If the void collapsed in that location, they would have observed these pressure switches pick up from the pressure shock, and that, in fact, did happen.

There was someone working in the area of this valve who identified a noise, a bang. There was also someone in the vicinity of the running RHR pump, which was on the B side, the D pump. They did not observe any indications of cavitation.

MR. LINDBLAD: Those symptoms that you just spoke of would be applicable to both air or steam voids. Why do they think it is a steam bubble collapse?

MR. HUNEMULLER: I think primarily just the volume that was involved given the known history of these types of events, which I will continue as we go through more of these events.

In this case, steam just seems to be the more likely case.

MR. LINDBLAD: Generally, I would look for steam bubble where there was a hot spot from some prior operation or the like. Is there any such?

MR. HUNEMULLER: That is essentially the case in this.

MR. LINDBLAD: I see.

MR. HUNEMULLER: This is a hot, stagnant loop of piping. They initiate --

MR. LINDBLAD: I'm sorry. How do they get both hot and stagnant?

MR. HUNEMULLER: Well, because these are the RHR LPCI injection valves, also the isolation valves, and there is no flow through this line. However, this recirc pump is running.

MR. MICHELSON: What is it flowing to?

MR. HUNEMULLER: Through this line to the reactor.

MR. MICHELSON: All right. And where is your point of entry back to the reactor? I thought it was through the injection line boiling water reactors.

MR. HUNEMULLER: The injection line is into the recirc loop.

MR. MICHELSON: Yes. Right, injection injects into the recirc loop, but it comes out through that injection line, and that is the recirc path, isn't it?

MR. HUNEMULLER: This would be in this piping here.

MR. MICHELSON: Right.

MR. HUNEMULLER: This pump is running.

MR. MICHELSON: Yes.

MR. HUNEMULLER: There is no flow through this pipe.

MR. MICHELSON: Okay. Now, those two valves are the two that show on your isometric there as so-called loop injection.

MR. HUNEMULLER: Right. They are the LPCI injection valves.

MR. MICHELSON: You have to flow through that to recirculate from the reactor back to the reactor.

MR. HUNEMULLER: In this case you are using the RHR B loop for --

MR. MICHELSON: Oh, the A was not running?

MR. HUNEMULLER: The A was not running.

MR. MICHELSON: Okay.

MR. HUNEMULLER: RHR A is out of service.

MR. MICHELSON: Then there is no hot water in the A pipe at the junction where you are claiming there is some heat nearby. If only the B is running, then that's over on another loop and that's -- if you would show your other picture again, the question is where is the heat coming from.

The A is shutdown, and I thought that pipe was relatively cool now.

MR. HUNEMULLER: Well, you start shutdown and cooling while you are still pressurized, and they continue to depressurize as they do this.

MR. MICHELSON: I think the question that was asked of you though is where is the heat coming from.

MR. CHAFFEE: I think the answer is that that particular portion there, the temperature of that line was established when the plant was operating, and I believe the situation is that they shut the plant down because there was no flow in that line.

It sounds like the speculation is that that piping area continued to remain -- most of its heat from when the plant was operating.

MR. MICHELSON: It was a timing question then? It was hot shortly before. I don't know how far.

MR. CHAFFEE: Right. And then the other thing is that when the void collapse actually occurred, that occurred at the end of a period of time when they were still depressurizing the plant, isn't that correct? Wasn't pressure still decreasing two hours before they actually had this occur?

MR. HUNEMULLER: Well, at the time that this occurred, they were believe 200 degrees.

MR. CHAFFEE: But hadn't the pressure been going down as they decreasing temperature?

MR. HUNEMULLER: Right. They had been decreasing pressure for some time, the two hours, the two and one-half hours.

MR. MICHELSON: They were coming down on both A and B and then you shut A off and just used B?

MR. CHAFFEE: They never used the line where the void was.

MR. MICHELSON: If you don't use that line, you never use the A pump --

MR. CHAFFEE: The A pump is a recirc pump that was always running.

MR. MICHELSON: Recirculating to what?

MR. CHAFFEE: To the vessels.

MR. MICHELSON: The line's got to go through the return line.

MR. CHAFFEE: No, because the recirc just takes from the vessel, puts back in the vessel but it is not part of shutdown cooling. They were using the B shutdown cooling pump, which is also a B recirc pump, and we are using that, but they were using the other side of the system's RHR system and they never used that particular leg.

MR. MICHELSON: I think we are getting recirc mixed up.

MR. CHAFFEE: Exactly.

MR. MICHELSON: It's the recirculation outside the vessel that I am talking about. You are talking about the internal recirculation, no problem there.

MR. CHAFFEE: Right.

MR. MICHELSON: But on the external you said that they never used the A pump.

MR. CHAFFEE: They never used the A RHR pump.

MR. MICHELSON: Okay. The area depicted there is the area that you see temperatures coming from water that might have been recirculated through A and if it was never recirculated it ought to be quite cool if not cold.

MR. CHAFFEE: I think the confusion is that in that drawing where it shows a recirc pump that A recirc pump is not part of shutdown cooling.

MR. MICHELSON: I am talking about A RHR pump.

MR. CHAFFEE: The A RHR pump is never used to circulate water through the --

MR. MICHELSON: That is all cold water there?

MR. CHAFFEE: The belief is that that line, which is inside the drywell, has a certain amount of heat.

MR. MICHELSON: That is outside the drywell. The drywell is on the left-hand side of the drawing where you show the penetrations. That is where the drywell is.

MR. CHAFFEE: The piping to the right of the penetrations are --

MR. MICHELSON: They have their RHR pump inside the drywell?

MR. CHAFFEE: That pump is not the RHR pump. That is the recirc pump.

MR. CARROLL: The reactor recirc pump, Carl.

MR. MICHELSON: I stand corrected. I understand the drawing now. Thank you.

MR. HUNEMULLER: I kind of lost track of where I was here. They believe their physical indications and their instrumentation agree with a void collapse in this location. Another possible location they evaluated was actually in the shutdown cooling suction line. However, due to a couple of fluid flow considerations they don't believe that is where that was.

[Slide.]

MR. HUNEMULLER: Number one, they didn't get a flow restriction that would have been caused by a void formation in their indications, and this is in the flow path so they should have seen that, and being in the flow path that should have cleared when the flow was established, so they don't believe that that was a very good location for that to have occurred and they believe this is where it happened.

MR. DAVIS: How high did the pressure surge go? Did they have a recording of that?

MR. HUNEMULLER: They got an analysis from their vendor. They reported they believed the pressure, peak pressure at that location, was I think they said 296 pounds and they think the pressure at this location was right at the actuation set point, about 75 pounds.

The reason they think that is because if you would travel down this line further to the RHR pump, RHR pump suction also has a pressure switch set at 100 which did not actuate.

MR. DAVIS: Thank you.

[Pause.]

[Slide.]

MR. HUNEMULLER: This next event was a Vermont Yankee event. This was in December of '93. In this case this is what I would classify as a more typical example. Shutdown cooling isolation while they were attempting to start the RHR pump and they opened the LPCI injection valve and the vessel level decreased three inches and it was reestablished 13 minutes later.

Again, here they believe the cause was the presence of air or steam voids in the shutdown cooling loop which produced pressure surges in the system, the same type of thing.

[Slide.]

MR. HUNEMULLER: And the events I am going to go through are really just the most recent events. There's a long history but the next one is the Pilgrim event.

[Slide.]

MR. HUNEMULLER: This was in July of '93 where a shutdown cooling isolation occurred again when an RHR pump was started and the injection valve was opened and in this case they re-initiated it successfully only two minutes later. In this case it was determined to be a momentary pressure transient that actuated the protective high pressure switches.

This is something Pilgrim believes will happen, does happen whenever they open that throttle valve as a pressure wave goes through their system and they are looking at something that was brought up earlier to take care of that problem, which was some kind of a time delay on the pressure switches.

MR. DAVIS: Well, it seems to me if you put that in then you have lost some major protection to the system if another kind of surge actually occurred.

MR. HUNEMULLER: The function of the pressure switches are to protect the design from exceeding its design pressure, actuating on these momentary pressure transients or shock waves from water hammer. The time delay I'm not sure would really make very much difference for their function.

MR. DAVIS: Would another solution be to just disable the switches when the primary system pressure is down to RHR entry conditions?

MR. CARROLL: No, because you are worried about some event that is going to cause a sudden repressurization.

MR. LINDBLAD: A low temperature --

MR. MICHELSON: Are these the ones they are using for that purpose?

MR. HUNEMULLER: I did not catch that question.

MR. MICHELSON: These are not part of the low pressure or repressurization and cold repressurization? Those are outside of containment. These I gather are inside. I am not positive.

MR. HUNEMULLER: These are inside containment on the recirc piping.

MR. MICHELSON: I don't think those for L-top. They are for something else.

MR. HUNEMULLER: They are primary pressure,

pressure boundary because of the low pressure shutdown cooling suction piping becomes part of that pressure boundary and you don't want to exceed its design pressure. I think that is the safety basis of those pressure switches is just for that function.

[Slide.]

MR. HUNEMULLER: And I will move on to the next plant then.

This is a series of events at Fitzpatrick that occurred in February and March and May of '93. All three occasions they managed to successfully establish shutdown cooling on the second attempt.

The second bullet is kind of a sideline, interesting aspect on the May 19th event. In their case, reactor water level decreased 17 inches. I should say that was indicated level. What they believe happened is that water moved from the downcomer region to the moisture separators upon pump start or because in this particular event they did not have forced circulation in effect so when they initiated forced circulation through RHR through the downcomer level down, given the indicated level decrease.

That messed up with their calculations. They did do an analysis and clearly established that RHR piping could not have absorbed that kind of a level decrease and it had to go somewhere else and the level decrease matched up with the volume of the moisture separators that they postulated.

MR. CARROLL: Now in none of these events were we anywhere near uncovering the top of the core?

MR. HUNEMULLER: That is correct.

MR. CARROLL: How much margin typically?

MR. HUNEMULLER: The level is maintained relatively high when you establish the downcooling. I am not sure that I have a good estimate to give you but higher than your normal level, probably higher than your normal high level alarm.

MR. MICHELSON: During post-LOCA recovery is it permissible to go back on direct recirculation towards the end of the event to get the thing down to cold conditions, get the reactor down? Is that permissible after a LOCA? It is not a prohibited mode as far as you know?

The first mode, of course is the beginning of the LOCA. You are drawing from the suppression chamber and recirculating into the reactor as a flooder, but once you get your elevations up you do not want to keep bringing all the water in. Then you start on a direct recirculation, is that right?

MR. CHAFFEE: I guess we think that is the answer.

MR. MICHELSON: Okay, thank you.

It is in that mode that you start worrying about some of these funny phenomena now showing up because of what's happened during the recirculation from the torus portion of the operation when you are going to ingest large amounts of air and so forth into the system.

MR. HUNEMULLER: Are we ready to move on?

MR. MICHELSON: Yes.

MR. HUNEMULLER: In spite of the last side issue, the root cause of the shutdown cooling isolations at Fitzpatrick were determined to be trapped air in their instrument tubing and just one of the pressure switches, only one is required to get the isolation.

MR. LINDBLAD: Tell me how that results in a high pressure signal.

MR. HUNEMULLER: When the air clears the system it is again a shock, in this case in the instrument tubing.

MR. LINDBLAD: How did it clear the system? Isn't the pressure switch a dead-ended line and where does the trapped air go?

MR. HUNEMULLER: I am not sure I can tell you where that goes. GE has postulated that is the situation.

MR. LINDBLAD: I am trying to visualize how that would give you a high signal.

MR. CARROLL: The trapped says that there needs to be a damper.

MR. LINDBLAD: But I don't know how that gives a high pressure isolation signal. That's what I am trying to understand.

MR. HUNEMULLER: I do not think it has been addressed in the responses either.

VOICE: As you depressurize that, previously pressurized air would expand perhaps beyond the length of the line or at a different elevation and then clear out that way, be replaced by water, which would then hammer on the switch.

MR. MICHELSON: I think they are concerned about the trapping of air in the instrument and instrument line and the only way you get that out is to vent it off. You have to go back to the instrument and then take the air out of it. You cannot do all of that during these transients, obviously.

MR. CARROLL: What he is saying is that there was air there when you were at high pressure, higher pressure, and as you go down in pressure, this air expands and comes out of the line and is replaced with water, which is causing the water hammer, which I have a little problem with.

MR. MICHELSON: It just expands. If it cools down later, it contracts again.

MR. CHAFFEE: Yes, but these instrument lines take a lot of different pathways. I mean they go up, they go down -- and so I guess it's hard to imagine but perhaps as it expands you could get some geometry, like you do for other water hammers where the gas escaping quickly allows, I guess it allows the water to go back in there and replace it and it causes a hammering effect.

MR. LINDBLAD: It was either boil or Pascal. They still transmit pressure, both the air and the water, and that is what I am trying to visualize.

You think there is some mechanism in which the trapped air is released and that causes a insurge of water, and that is what I don't visualize.

MR. CHAFFEE: That is again speculation. I don't have a good handle on it.

MR. LINDBLAD: Thank you.

MR. HUNEMULLER: I don't think that was addressed in GE's either. Given this is a postulated cause, their immediate corrective action was to ensure the sensing line was vented and backfilled, as you mentioned, and their long-term corrective action is to reroute the sensing line.

MR. CARROLL: To get rid of air traps?

MR. HUNEMULLER: To get rid of the air traps, yes.

MR. SEALE: I believe you said you had this event three times in a relatively short period of time.

MR. HUNEMULLER: Yes.

MR. SEALE: Since then, since they have done this immediate corrective action, have you had a similar thing happen again? Have you had the opportunity for a similar thing to happen?

MR. HUNEMULLER: I am not aware of any others happening at Fitzpatrick but I don't know their operating history to tell you --

MR. SEALE: It would be nice to know whether this in fact corrected the problem. That would suggest that even though we do not understand exactly what the mechanism was that at least they did something that did the right thing.

MR. MICHELSON: What was thought to be the source of the air that became entrapped, if it was air?

Now we have been speculating back and forth about steam and air. I assume this was air in this case, is that right?

MR. HUNEMULLER: Right.

MR. MICHELSON: Where did the air come from?

MR. DAVIS: Instrument tubing.

MR. MICHELSON: It didn't come from the instrument tube. Those are all vented at the time you set up the instrument.

MR. HUNEMULLER: It is postulated that air enters the system during draining, flushing and filling operations that go on prior to establishing shutdown cooling and like I said, their immediate action was to make sure that they properly vented and backfilled.

MR. MICHELSON: That is when they thought they got the air in or how they got it in, okay.

MR. CARROLL: Does the gentleman from Cooper have any insights into this? You can come sit up here, if you like.

MR. SMITH: I am Greg Smith, with Nebraska Public Power, which is the licensee for Cooper Nuclear Station. I can't really speak, I guess, on what Fitzpatrick does, or their particular evolutions. But, we do periodically perform backfilling, et cetera, on various transmitters.

Again, I'm not sure how our evolutions compare with theirs, but it is a potential means of introducing air.

To the best of my recollection, we haven't had problems in this regard, backfilling and introducing air into the instrument lines.

But, again, I can't speak for Fitzpatrick plant.

MR. CARROLL: Okay. Thank you.

You could sit there, if you want, in case there are other questions. Or, you can leave.

MR. HUNEMULLER: The next bulletin I just wanted to bring up, these are just some more recent examples. Cooper, Grand Gulf and Vermont Yankee have had previous similar events, all of them attributed to deficiencies in the shut-down cooling. Call them warming procedures, but those are the draining, flushing, refilling.

MR. MICHELSON: Are these instruments outside of containment?

MR. HUNEMULLER: These pressure switches are --

MR. MICHELSON: The transmitters, are they outside of containment? Are the sensing lines penetrating containment? At the Cooper.

MR. SMITH: Yes, I would say that is true for all BWRs. These are outside and, in fact, we have signs and other precautions posted to prevent any sort of inadvertent bumping, or any mechanical agitation of these devices during operation or other evolutions.

MR. MICHELSON: But, you back and vent fill from outside of containment?

MR. SMITH: Yes, sir.

MR. MICHELSON: Thank you.

MR. HUNEMULLER: Thank you.

MR. DAVIS: Were any of these events processed through the action and sequence precursor program, or are they going to be, do you know?

MR. CHAFFEE: I don't believe any of them were, but I don't know that for a fact. And, in part, because they were set-down events. And I think what's true is typically the S process is not used on shutdown events.

MR. CARROLL: I don't see them being any more than a nuisance. I don't see a lot of safety significance to them.

MR. MICHELSON: Let me give you a model then of which this is a small indicator of the kinds of things it could get into.

The problem is that if you have a LOCA, the first thing you do is blow down a large amount of containment air and steam into the suppression chamber.

MR. CARROLL: Correct.

MR. MICHELSON: The steam gets partially condensed in the water. The air gets left behind as fine air bubbles which slowly rise to the surface. But, in terms of all this agitation going on, the suction for the RHR is generally very close to at least one downcomer somewhere, since there's so many.

You pick up a great deal of error. I believe you will pick up a great deal of error in the water being pumped from the suppression chamber.

In fact, it used to be a problem of NPSH effects it.

MR. CARROLL: I know what we're talking about. That is not these events.

MR. MICHELSON: No, wait a minute now. You haven't followed it far enough. Now, as that air passes through the RHR during the early injection phases, it's going to pull out where there is a nice separation point.

And that is the air that you're not worried about affecting instruments for a further post-LOCA operation later on. And that's where I think you have to think about.

MR. LINDBLAD: I can understand how they might affect DP cells in level instruments. I have problems understanding how they affect pressure switches.

MR. MICHELSON: Well, they may even affect flow, depending on your piping configuration. You can have high-point loops that will get virtually choked off with a concentration of air being stripped out of the water as it passes through the loops that was picked up back in the suppression chamber.

So these things are -- this is a lesson during shutdown, but it has potential implications on how things work during an accident.

MR. LINDBLAD: My concern is even simpler. I'm worried about the RHR isolating and then the valves failing closed, not being able to operate, or not being able to reopen them.

I've heard about these this morning.

MR. CARROLL: All these valves, of course, can be manually opened, I believe, if you had to.

MR. DAVIS: If you had time.

MR. CARROLL: You're shut down. You've got lots of time before the temperature is going to rise very far.

MR. MICHELSON: I had not thought about the possibility of interfering with valve operation, only with the fluid flow itself and the -- because of trapping of air in the piping configuration. It's very sensitive to the configuration.

Also, this air gets stripped out in the pump itself, and you tend to build up air in the top part of the section of the pump.

And during post-accident, this is not the time to be starting to raise these kinds of questions. And this is a little hint as to air does get into these systems. It can be a real problem. And it's just a word of caution.

MR. CARROLL: Oh, I mean, I think what you're talking about is an interesting issue. But I don't think - it's a very longstanding issue, but I don't think it's this issue.

MR. MICHELSON: No. This is a small hint of what kind of problems you get once you get air in the systems.

MR. CARROLL: Pete, even if you can't open the valves, what happens?

MR. DAVIS: You heat up. You've got the reactor vessel vented. You heat up and boil off.

MR. CARROLL: Yes, they do have the vessel vented.

MR. DAVIS: Yes.

MR. CARROLL: So now you're also going to postulate you can't close the vent valves?

MR. DAVIS: If you could, that would be a momentary fix, but you'd eventually get the pressure up to some relief valve setting.

MR. CARROLL: No, I'm not saying -- you can dump the steam through the bypass system, to the condenser. There's a lot of things you can do.

MR. DAVIS: That's why I'd like to see it processed through the sequence program, to see if, in fact, it --

MR. CARROLL: But I think Al is right. I don't think they are at present geared up to do all of the shutdown events.

MR. MICHELSON: I think the thing to worry about is less information that might be coming from instruments that have an air problem. And the operator not recognizing that they have an air problem, and maybe taking wrong operating steps. I think that's how you would start backing into a serious, you know, the kind that would lead you to think we'd worry about an accident precursor program.

MR. CHAFFEE: As far as 'as builts,' I think there's activity underway to try to get some shutdown models. I guess I'm not positive as to whether or not that shutdown model activity, if that is clearly linked to ASP or not.

Do you happen to know the answer to that, Bob?

MR. SEALE: Based on information that we got from AEOD on the, you know, the, quote/unquote, "ASP Program," I don't believe they have any shutdown molds in place. Anything they would do on a shutdown event would be ad hoc.

And they would restrict themselves to more serious situations. I believe, on the NRR side, staff has explored modeling shutdown kinds of events, but I don't believe there's anything --

MR. DAVIS: I do know that Sandia has recently completed a shutdown risk model for Grand Gulf. And it's a rather extensive assessment of shutdown risks. And that could be used, I think, to look at some of these events, possibly.

MR. CARROLL: As well as Brook Haven has done the same thing on Surrey. Those reports are now out.

MR. SEALE: These are all BWRs rather than Surrey.

MR. CARROLL: Well, I'm just saying that's a basis for getting BWRs into the shutdown business.

MR. POWERS: Pete, I think the shutdown PRAs are still pretty primitive on both of those studies.

MR. DAVIS: The one that I saw that Mr. Whitehead is working on at Sandia has extensive event trees. And --

MR. CARROLL: Except it is just a fraction of the total possible event trees.

Al, that brings up a point. Pete has asked that when you guys come down and make these kind of presentations, that you routinely find out what's going on with AEOD on ASP with respect to the event.

MR. CHAFFEE: Normally, for event reviews that we do, part of that activity does include looking at the event from a PRA standpoint.

And, frequently, what will happen in the early portions of the review is the PRA branch and NRR will do S type analysis for it as part of that effort.

The final effort that's done by AEOD will come sometime after that. But, normally, if there's a PRA that could be done or seemed to be appropriate for the type of event we were doing, something along that line would have been completed before we would come here.

That's normally the case. And, I think, in fact, in the past, when we've come down here, we've given you some PRA information. We haven't always used the term ASP.

MR. CARROLL: On some cases, you have.

We would like to see this as a routine part of the presentation.

MR. CHAFFEE: Okay. Would you like us to briefly go through the rest of these slides and then move on to support?

MR. CARROLL: I think we've got to do that if we're going to meet a time line.

MR. CHAFFEE: We need to be done by noon; is that right?

MR. KRESS: Eleven forty-five.

MR. CARROLL: Oh, 11:45.

MR. CHAFFEE: If that's the case, then we ought to just go to Sequoya, I think.

MR. CARROLL: I think we can infringe a little bit on 11:45. We've only got one letter to talk about.

MR. SEALE: We've got several.

MR. CHAFFEE: Why don't we just move on to Sequoya. Move on to Sequoya. Okay.

[Slide.]

[Pause.]

MR. CHAFFEE: The last two slides, really, what they're saying is there is some work ongoing to develop a notice as regards to this particular problem at Cooper.

And we also mentioned the fact that there was previous generic communications in this area; particularly it mentions the GE SIL that went out back in '76.

Dave, you might give a little bit of your background before you start.

[Slide.]

MR. LaBARGE: Good morning. My name is Dave LaBarge, Project Manager for Sequoyah, NRR project manager. I've been with the NRC for about five years now. I've been project manager for Sequoyah for about three and a half.

Prior to that, I was project manager for Fitzpatrick. And before coming to the NRC was an operator, an operations engineer at Vermont Yankee for 19 years.

Before that, I was a Navy nuke.

[Slide.]

MR. LINDBLAD: Mr. LaBarge, you show this as being a gas bubble event. The previous speaker did not say bubble. He said void. Is there a distinction between these?

MR. LaBARGE: No, there is not.

MR. LINDBLAD: Thank you.

MR. CARROLL: We talk about bubbles in pressurized water reactors and voids in boiling water reactors.

MR. MICHELSON: Is that what you do?

MR. CARROLL: Sure.

MR. LINDBLAD: I have lost the bubble somehow.

MR. LaBARGE: December 17, 1993, when the pressurizer vented into the containment and conditions established to perform a containment and degraded leak rate test on unit one. A decreasing pressurizer level was noted by the operators as containment pressure was increased for the test.

Investigation revealed that the nitrogen bubble existed that displaced approximately 30,000 gallons of water at the reactor vessel and steam generators.

This represents a little less than one-third of the primary containment system water inventory.

[Slide.]

MR. LaBARGE: I've got an elementary drawing here that lays out the reactor coolant system components that we were concerned with in this event. westinghouse is a four-loop PWR. At the time of this incident, it was operating a mode 5, which is cold shutdown.

There was very little decay heat. The plant had been shut down for the previous nine months, and refueling outage had been completed. The licensee calculates that the decay heat was about .87 megawatts thermal.

[Slide.]

MR. LaBARGE: The reactor vessel, four loops, RHR returns are shown to each loop into the cold legs. Charge of water goes into the cold leg and RHR supply comes off the loop for head vent.

We talked about all of these components and the pressurizer PORVs. PORVs were open at the time of the event. And one of them was disconnected.

MR. LINDBLAD: And you talk about decay heat. You didn't mention Guillian heat where the pumps -- how many pumps were running.

MR. LaBARGE: At the time, there were two RHR pumps running. None of the reactor load pumps were r nning.

MR. CARROLL: That is not much heat.

MR. LaBARGE: This event started when on September 6, 1993 they performed a sweeps events evolution of the reactor coolant system, which is a method they have for removing any air that might be trapped in the reactor vessel and in the steam generators after the refueling outage.

The reactor vessel and the steam generators were as a result filled and pressurizer level was at 60 percent.

There was very little work after that being performed on unit one because most of the efforts were being performed for unit two to get it ready for operation.

The RHR system was recircing the reactor coolant system, and the centrifical charging system was recircing approximately 100 GPM, or thereabouts for reactor coolant pump seals.

It maintained pressurizer level, the CO flow was low, most of the water was being maintained in recirc through the cold leg, from the cold leg to the let-down heat exchanger into the volume control tank then being pumped with a charging pump into the reactor cooling system for the pump seals and charging, maintained reactor cooling system level in the pressurizer. Nitrogen gas was being maintained in the volume control tank to maintain pressure at about 20 pounds.

[Slide.]

MR. LaBARGE: On November 12 a problem developed with the cooling water valve to the let-down heat exchanger that caused a significant drop in VCT temperature. This valve was -- had a problem with it. They were concerned with the valve failing shut on loss of control signal so they went in and made a modification. And when the valve was reenergized, the valve went open.

Prior to that, the valve was in a stable position and the temperature of the VCT was gradually decreasing with ambient river water temperature. So they had a changing temperature in the VCT with the water being charged in under those conditions.

The temperature in the VCT and the temperature with the valve, the cooling water valve, contributed to the problem, to the magnitude of the problem. It was not the cause of the problem, it just contributed to it.

On December 12, they started containment integrated leak rate tests, pressurizer level decreased as containment pressure was increased. Remember, the pressurizer was vented to the containment and the containment was buttoned up.

Then operations and plant management discussed the situation, analyzed it and continued on with the leak rate tests.

The original estimate was about 5,000 gallons was added to the pressurizer to maintain level. A later estimate placed the value at about 8,000 gallons.

This change in level with pressure had not been experienced during previous tests so this was something new.

They continued on with the test and completed the leak rate test on December 20. Then, as they released the pressure from the containment, pressurizer level increased. They had anticipated this increase and they were ready and they at that time let down from the primary system about 8,000 gallons to the radwaste system.

The next day, the operations department requested that technical review be conducted to see what the problem was and analyzed it further and at the same day they vented the reactor vessel head.

On December 28, compensatory actions were instituted by operations department to require monitoring of the reactor vessel level indication system and weekly venting of the reactor head and to no longer take credit for the fill steam generator tubes in lieu of an RHR train. We will get into a little bit more of this later on.

On January 7, TVA determined that nitrogen from the VCT was a source of gas. In other words, that nitrogen-covered gas was being injected into the reactor vessel by the charging system.

On January 13, TVA determined that reactor vessel level had decreased to the top of the reactor coolant system hot legs and on January 24, sweeps and vents were performed and the reactor coolant system pressurized to approximately 200 pounds. At this time, the event was pretty well concluded.

All during this time, engineering and engineering support department was evaluating the situation and trying to determine exactly what the situation was, what the size of the bubble was and the actual condition of the reactor coolant system.

[Slide.]

MR. LaBARGE: As they looked at it to determine that nitrogen covered gas was coming from the VCT, was coming out of solution in the reactor coolant system and steam generators due to the lower pressure and higher temperature that existed in the reactor vessel and steam generators. VCT was at 20 pounds and the temperature was between 52 and 95 degrees. It started off in September after the sweeps and vents were performed around 95 degrees and before the event was over the temperature had decreased to 52 degrees.

Remember the RCS was vented through the pressurizer fuel RVs and so you had an air bubble up in the top here or an air volume at the top of the pressurizer and injecting this gas filled -- or this water and gas into the reactor vessel ended up voiding the top of the reactor vessel as it came out of solution due to the difference in temperature and pressure and in the steam generators. The tubes were voided. Some steam generators may have been more voided than the others because there really was no flow through the steam generators at this time. RHR flow was through the reactor vessel.

Once water level decreased to the top of the hot legs, as it came out of solution in the reactor vessel, air would have traveled down, the nitrogen gas would have traveled down the top of the pipe and entered into the steam erator -- the pressurizer and gone out the vent.

Significant to note that the pressurizer surge line, which is this line here, taps into the hot leg a little bit below the top of the hot leg. It's a horizontal run, there's no dips in that surge line as it goes from the reactor coolant system piping into the pressurizer.

On loop 4, RHR suction is off near the bottom of the reactor coolant loop. So an air bubble forming at the top of the pipe, if it tried to go lower, it would have vented out through the pressurizer.

So they kind of established a limit to how low or how large a volume could be developed.

MR. LINDBLAD: You slide shows the pressurizer having a capacity of 7,500 gallons. Is that an 1,800 cubic foot pressurizer like most?

MR. LaBARGE: I am not familiar with that value.

MR. LINDBLAD: Is the capacity up to the water level?

MR. LaBARGE: That is the capacity of the water in the pressurizer at the top.

MR. LINDBLAD: It is the volume of water, not the capacity of the pressurizer?

MR. LaBARGE: Right. It is the --

MR. DAVIS: I'm sorry, I must have missed something. The sequence of events suggests that the primary system must have been open to the containment at some location.

MR. LaBARGE: Right up here at the PORV vent.

MR. DAVIS: I thought that went to the pressurizer relief tank.

MR. LaBARGE: It does go to the relief tank. There is a vent port on that tank. There is also a vent in the line that goes into the tank.

MR. DAVIS: And they were open?

MR. LaBARGE: The PORVs were open and one was removed from the pipe. The PORV system was vented purposely for the leak rate test.

MR. DAVIS: Okay, thank you.

MR. LaBARGE: I did not go into the primary leak rate test, primary containment leak rate test. I assume you are familiar with those.

Another problem that surfaced out of this is there was a failure to monitor the reactor vessel level indication system. However, you've got to recognize that RVLIS really was not designed for operation or for use during Mode 5 operation. It was designed as a proposed TMI instrument system to be used in Modes 1 through 3 -- 1, 2 and 3.

MR. CARROLL: Why doesn't it work in Mode 5?

MR. LaBARGE: It will, but the procedures did not exist for its use in Mode 5. It was installed for Modes 1, 2 and 3 and that is as far as the procedures went.

MR. CHAFFEE: In this event it did get information on November 29 when they did the calibration on it. It indicated that the vessel level was 70 percent, which the case suggests below the top of the hot leg.

MR. LaBARGE: It was indicating for a portion, but it was not being monitored by the operators.

MR. CARROLL: What you are saying is the instruments worked, the operators simply did not take advantage.

MR. LaBARGE: There are a couple of reasons for that. One, it was not designed for Mode 5 operation, another being that there was maintenance being performed on the instrument and it was turned over, maintenance was completed. However, there were still little tags on the instrument that said it was still being worked on and therefore they did not rely on it for that reason either.

But it did, when they looked back on the incident, it did show that the levels were changing and the levels were at what this drawing depicts to some extent, although it is very difficult to say what are the actual levels.

MR. CHAFFEE: The licensee in their analysis did say that based on what they observed on November 29 that probably what you see there is close to what the configuration was ont hat date, at least which was several weeks before they did the integrated leak rate test.

MR. LaBARGE: After the event when they went back and analyzed.

MR. CHAFFEE: They are not sure how much prior to November 29 they had reached that state.

MR. LaBARGE: Minimum water level was slightly above the top of the hot legs and it was a little over five foot above the top of the core and about -- when they do steam generator work, of course, you go down to midloop operation which again is in tne middle -- they call it the middle of the hot leg. They were 10 inches above that level, so that is the minimum level that they normally operate at. They were above that so they were not at midloop concerns for level.

MR. CARROLL: And there was no indication of any problems with the RHR pumps?

MR. LaBARGE: That's right, no indication whatsoever that the RHR pumps, at the time or subsequent, were in trouble. The evaluation and analysis has not pointed out any problems with the RHR pumps.

MR. CARROLL: This leads me to wonder whether people could take some advantage of the RVLIS system in the context of dealing with the PWR instrument issue and the shutdown risk rule.

MR. LaBARGE: It does make sense.

MR. CARROLL: One of the points the Staff is making here is you need some diverse kind of instrumentation. Maybe you've got it already.

MR. GRIMES: Our recent review of the CE System 80 Plus tech specs would have included a specification that the RVLIS will be operable in all modes, so it does take advantage of the existence of it.

MR. MICHELSON: You maintain it?

MR. CARROLL: Or do not maintain it in midloop.

MR. LaBARGE: I think you will find that Sequoyah at least will ensure that they have a RVLIS indicator any time that they are in any kind of mode of operation where it would be important to have. In other words, the system buttoned up with the vessel head off, of course, you can see the level. But any time the system is buttoned up I think you will find that they are going to have the RVLIS system indicators.

MR. CHAFFEE: It also turned out in a Salem event a couple of months ago where a resident looked at the system. There was a void, the plant was shut down so they did not depend on it. But it did provide useful information.

MR. CARROLL: When we respond to the Staff's response to our letter on shutdown risk, maybe we will point that out.

MR. LaBARGE: The other concerns we have relate to the fact that the reactor coolant system level was not known to the operators. They did not know that they had this level of problem, that the level was at this point.

MR. CARROLL: It's right up there in the pressurizer. I have heard that before.

MR. LaBARGE: It's not a BWR, it's a PWR, right. The situation is not covered by procedures or training. Normally, the tech specs require two methods of decay heat removal. But they were not always available during this three-month period. The tech specs allowed them to remove one RHR loop from service as well, as long as the four steam generators are available. But at various times during this period of time, this three-month period of time, one RHR loop was removed from service such that both were not available for 13 percent of the time.

The water level was below the top of the steam generator tubes so even though the tech specs allowed them to rely on the cooling capability of the steam generators, there was 13 percent of the time that both loops were not available.

MR. DAVIS: Would you even need forced circulation at this low of a decay heat level?

MR. LaBARGE: Right. This is an appliance problem.

MR. DAVIS: Not a real problem.

MR. LaBARGE: Not a real problem, a compliance problem. But other plants could have a problem if they got into the situation with more decay heat.

MR. DAVIS: That's true.

MR. CHAFFEE: We mean they were not available for tech specs for 13 percent.

MR. LaBARGE: 86 percent of the time they were available.

MR. CHAFFEE: They were declared inoperable because they were doing maintenance or something.

MR. LaBARGE: They were lined up to perform maintenance, but they could have gotten the system operational within a very short period of time, 96 percent of that time.

Subsequent actions. Subsequently, TVA modified their shutdown procedures. NRC issued Information Notice 94-36 and notice of violation. The Staff is evaluating the implications of this event in the context of the shutdown rule.

That concludes my presentation and I am open for questions.

MR. CARROLL: Has Westinghouse Owners Group taken any action that you know of on this particular item?

MR. LaBARGE: I have heard of no action by the Westinghouse Owners Group. There may be, but I have not heard of it.

MR. LINDBLAD: Mr. LaBarge, do I recall that as you were setting the stage for this discussion you spoke -- Sequoyah is a two-unit site -- that more interesting things were going on at the other unit?

MR. LaBARGE: Yes. They were trying to get Unit 2 restarted.

MR. LINDBLAD: Does that suggest the plant engineering people were not available to help the operators review what was going on in this unit? Was that a problem? Was that a diversion of interest?

MR. SCHAEFFER: I do not think that was a factor at all. It was just a long-term shutdown and they were trying to get the other unit up, and this one the operator should have picked up on.

MR. LINDBLAD: So they had good oversight management?

MR. SCHAEFFER: With the exception of management requiring them to look at RVLIS, yes.

MR. LINDBLAD: Thank you.

MR. CHAFFEE: One other point, they talked about the fact that for the volume control tank the temperature went down in part to the cooling water to let down the heat exchanger becoming fairly significant at the point where the temperature went down. One thing that was interesting was the actual occurrence of that valve, control valve, failing full open did not actually occur until after they had already checked the RVLIS level indications, so they were already down to what we call an equilibrium type of state, even without the valve failing open, just the temperature decrease that occurred due to the normal operation of this system was sufficient apparently to allow them to get to that condition within the three months or less that occurred. So all that did really did was make the phenomenon even more aggressive during the subsequent period of time.

MR. SEALE: What temperature did that get down to?

MR. CHAFFEE: It got down to 60 degrees in January, it was 80 degrees in October. Over a period of time it went from about 80 degrees down to about 50 degrees.

MR. SEALE: That stuff was really loaded up with nitrogen then.

MR. CHAFFEE: It is interesting. It sounds even with the 80 degree VCT, 100 degree RCS temperature, you can expect the gas to come out at some, I guess, fair rate.

MR. LaBARGE: Yes, significant rate.

MR. CARROLL: Any additional questions on this event?

[No response.]

MR. CARROLL: We thank you for a good presentation. As long as we are ahead of schedule, it occurs to me, I keep asking presenters what their backgrounds are. I will bet people will be interested to know why Al Chaffee is smart enough to run the event assessment branch. What is your background, Al, not that I don't know?

MR. CHAFFEE: My background is, I have been in this job for four years, prior to that I was in Region V for about 11 years. While I was out there, I was involved -- I was a Deputy Director for the Division of Safety and Projects for a while. Previously I was a Senior Resident at San Onofree for about four years, and prior to that I was in the Navy Program for about seven years.

MR. CARROLL: Very good. I turn it back to you, Dr. Kress.

Thanks for very good presentations.

MR. KRESS: We are going to spend the next few minutes before lunch looking at a reconciliation of ACRS comments. You have before you this strange color with a 10 on it.

[Discussion off the record.]

MR. KRESS: At this time, let's break for lunch and be back about 2:00.

[Whereupon, at 1:00 p.m., the meeting recessed, to reconvene at 2:00 p.m., this same day.]

AFTERNOON SESSION

[1 00 p.m.]

MR. KRESS: The next item on our agenda is to hear a report from AEOD on the Potter & Brumfield motor driven relay failures.

Pete, are you running this particular show?

MR. DAVIS: No, Jay is.

MR. KRESS: Jay is.

MR. CARROLL: How did you figure that?

MR. DAVIS: I read the agenda.

MR. CARROLL: Well, I just read the agenda too and it says Davis.

MR. KRESS: It depends on which part of the agenda you are looking at.

MR. DAVIS: I'm reading page 3.

MR. CARROLL: I'm reading page 2 of tab 11.

MR. DAVIS: I confess. I did request that this be presented to us.

MR. KRESS: Why don't you two guys proceed. I'm turning the floor over to you.

MR. CARROLL: Why don't we just turn it over to Bob Spence.

MR. SPENCE: My name is Bob Spence -- can you hear me? -- with AEOD.

MR. CARROLL: Bob, I think you could put the mic up just a bit.

MR. SPENCE: Thank you.

[Slide.]

MR. SPENCE: What we are here this afternoon to talk about is Potter & Brumfield MDR relay. This is one right here, and I will pass it around in a little bit.

I got interested in this in the fall of 1991 when River Bend submitted an LER indicating that they thought they had a common mode failure mechanism working in their MDR relays, and started investigating and found out that there were about 35 or 36 plants that had these type of relays.

MR. CARROLL: We always get confused, Bob --

MR. SPENCE: Yes, sir.

MR. CARROLL: -- when the Staff comes down and talks about "plants" because very often they mean units when they say plants.

Here, you mean plants that consist o. one or more units?

MR. SPENCE: Here I mean units.

MR. CARROLL: Ah, okay.

MR. SPENCE: Okay. I will try to remember the word "units." If I say plants, I mean units.

MR. CARROLL: Okay.

MR. SPENCE: I went through NPRDS data and found

99 -- I'm sorry -- I found 106 failures. I went out to several plants and I found more failures that were not documented.

I took the data from 1984 to 1992 and used that because that was the beginning of the NPRDS information.

MR. DAVIS: Excuse me. I don't mean to interrupt. These one that you found that were not documented, should they have been?

MR. SPENCE: Yes and no. A combination thereof.

MR. DAVIS: Some should have been documented?

MR. SPENCE: Yes. I found some non-safety related ones that were, you know, not necessarily documentable through NPRDS, and I did find some that were.

MR. DAVIS: Thank you.

MR. SPENCE: Okay. The other thing I found about NPRDS is that they did not have a full scope of how many relays were in each plant in safety related applications.

The interesting thing about these relays is the combinations of failures. Of the 124 failures I looked at, about one-third of them were involved in ten events that had multiple failures at the same time.

MR. CARROLL: Let me see if I understand what that means. A third of them were involved in 10 events?

MR. SPENCE: Right. In ten different time periods, okay?

MR. CARROLL: Okay.

MR. SPENCE: At one plant, two would failure or five would fail or three would fail?

MR. CARROLL: Simultaneously?

MR. SPENCE: Simultaneously.

MR. CARROLL: All right.

MR. DAVIS: Like at River Bend, for example?

MR. SPENCE: That one was a double, yes. Susquehannah had two's and three's and five's.

MR. SEALE: You are saying that 40 relay failures involved ten events with the multiples that involved?

MR. SPENCE: That's correct. Now, if a failure has occurred or were found -- excuse me -- were found either during testing or during a demand event itself.

MR. CARROLL: So when you find a failure during testing you don't know exactly when it happened?

MR. SPENCE: Well, that depends. That is usually the case. At River Bend they traced it back to when they lost DC power in one case. You know, when the relay went one way and it just never returned, so they were able to trace it back to a specific event on each of the two trains.

MR. CARROLL: Okay.

[Slide.]

MR. SPENCE: The report, page 45 and Appendix C both indicate lists of the type of safety significant events that have occurred to date because of failures of these relays. I will just read out a couple to give you an idea. A half scram was prevented in one plant. There was a reactor trip on spurious MSIV closure. There was a spurious channel trip.

A train of SFAS did not reset after a reactor trip. An ESF signal could not be bypassed. Emergency diesel generators could not load onto its grid. Voltage regulators failed to operate on EDGs.

It prevented two reactor recirc pump MG sets motored from tripping. Containment isolation signals did not work. Back up pressurizer heaters did not shut off, and a whole number of pumps would not stop, condensate pumps, sodium hydroxide pumps, et cetera, because of failures.

There were a number of other things that happened -- that did not happen but were found in operable during testing. Stuff like safety injection signals being inoperable, well pressure safety injection pump wouldn't start or emergency service water pumps wouldn't start, 125 volt DC power was inoperable. Many, many different things.

These relays are used in reactor protection system usually as a shunt. They are used in the actuation lodge of ECCs, ESFs.

And the important thing here is, for example, if there was a failure in an ADG in train A, a similar -- a relay failure could take out safety injection, for example, in train B.

[Slide.]

MR. SPENCE: Now, that I have your attention, I will go through this thing and explain how it works, what its failure methods were, and so forth.

The only difference in the various model numbers --

MR. LINDBLAD: Mr. Spence, before you get into this, is it correct that nuclear plants have a higher density of this type of relay than other industrial plants? And do I remember that that's because it happens to be seismic qualified?

MR. SPENCE: These were originally designed as o 1-E relays, the whole pedigree, but since then Potter & Brumfield has gone ahead and turned it into a commercial grade item.

They are out in industry. As well, I know they were in U.S. Navy ships as well. DOD got them all out of there or got them changed out already in the subs.

I do not know on the other commercial side.

MR. LINDBLAD: Yes. I guess I've designed both nuclear and non-nuclear plants and remember that in nuclear plants we use this kind of relay and in non-nuclear plants we used another which I don't think has this problem.

The difference was because of a qualification test that these passed very well for, I guess, seismic and shock loading which makes the application seem right.

You weren't with us this morning, but we were talking about industry experience vis a vis qualification testing of components, and here is a case where perhaps qualification testing in one narrow sense has driven us to use something that didn't have as much industrial experience as the conventional CO relay or whatever other we are talking about.

Thank you.

MR. DAVIS: Did DoD elect to change out their relays on the basis of their own experience with failures?

MR. SPENCE: No, sir. On the basis of our information report in January of 1992.

MR. DAVIS: Thank you.

MR. CARROLL: I might mention that in tab 11 we have Bob Spence's special study report if you want to be glancing at that while he is talking.

MR. SPENCE: There are many different model numbers out there. The big reason for getting this relay in the nuclear power plants is that it will interrupt the 10-amp AC circuit and it has its various lower amperage ratings for DC circuits, and it has multiple contact ducts. If you want more contacts hitting at the same time, you just stack these up, up to six deep, and so you get different model numbers. You can run them on the coil on different voltages, wattages, and so forth.

Regardless of the model number, they are basically the same component.

It works by this shaft right here turning, which is this thing here, and it turns about 30 degrees. There are two types of these relays: latching and non-latching.

The non-latching has a spring connected to this rotor that returns it back to its original position after the coil energy is shut off.

On the latching relays, you have two coils. One coil of which is always energized so it goes back and forth.

MR. KRESS: And it is basically an auxiliary relay?

MR. SPENCE: Yes.

MR. KRESS: That it doesn't try to sense --

MR. SPENCE: It is a control system relay. It is used for all kinds of uses.

MR. KRESS: And so it has a standard solenoid type voltages and currents that are operative?

MR. SPENCE: A 125-volt DC, for example, or a 28-volt. You know, that type of thing.

There is a little piece their shaft fits on, a little spacer down at the bottom, and that is important later. You can see the two coils which are going to be -- I will demonstrate -- that is kind of the problem here.

And down at the bottom you will see a bearing that the shaft goes through and a similar bearing on the top of this.

I am also passing around some pictures of the end bell. That shows some of the corrosion and varnish offgassing on how it condensed there.

And this is on the bottom of the shaft itself, on the rotor shaft.

And this is that small space I was mentioning, which also condensed.

The main failure mechanism on these things was offgassing from the varnished coils. The manufacturer, Potter & Brumfield changed out the coiled to -- the finish -- from varnish to epoxy to avoid outgassing, and indeed that gets about -- it is 100 to 1 ratio of outgassing, so that should be corrected in the future.

There was also chlorine released from rubber drommets, paint and PVC wiring.

There, offgassing collected here and here in these very small spaces, and it prevented not only the shaft from turning, but it helped stop the end play. That shaft needs a ten to twenty thousand end play.

In that small areas you would get either a wet or dry mixture of carbon, oxygen, sodium, calcium, potassium, zinc, silicon, sulfur, chlorine, copper, iron and chromium, would you believe.

MR. CARROLL: But, no ceborgium?

[Laughter.]

MR. SPENCE: That's about all it didn't have.

That was the primary cause. The licensees in the NPRDS report did not say, hey, it was due to offgassing.

A lot of time they took these things and the relay didn't work, so they threw it in the can. They put in a new one and they didn't investigate it. I think one of the big conclusions in the report is that the relays need to be treated, and the root causes found early.

Another area that was causing problems was the oversized coil. They originally started putting these in and in the higher wattage coils the more windings you have. Of course, they did not change the envelope, so it just got up and touched the top of the shock plate.

Well, these things then would be shimmed appropriately so they would have the right clearance, and when they were in service and they were energized, the coils changed shape and relaxed a bit.

And they changed so that this thing would not always be at the right location, and these shock plates also would be shoved up against the [illegible] and prevent rotation there too.

After changes from 1985-1992 to try to correct these problems, about one to two a year.

MR. CARROLL: Was part of his problem the fact that he's used to dealing with non-energized auxiliary relays which are typical in other applications, and a nuclear plant you typically have energized so it's fail-safe?

MR. SPENCE: These things were rated for -- the design specs from G.E., for example, came in solidly to have 40 years life, full energization, so forth.

I can't speak for what the manufacturer --

MR. CARROLL: But he said, well, these were something similar, has worked very well in industrial applications, and overlooked the fact that 40 years of energized is --

MR. SPENCE: To put this into perspective for you, 70 percent of the failures occurred in normally energized relays. That left 30 percent in normally de-energized, too.

MR. CARROLL: Okay.

MR. SPENCE: So there's a combination of when the unit is down maybe that normally energized relay is now de-energized, and vice-versa.

MR. CARROLL: Okay.

MR. SPENCE: So there's --

MR. LINDBLAD: I think another characteristic, particularly when we're talking about contact problems, is the other types of standard relays have a wiping action on the contact. And these don't seem to wipe.

MR. SPENCE: They do not at all. You're correct.

MR. LINDBLAD: And that wiping keeps the contact clean.

And the other relays live in the same off-gassing environment you're talking about. They all have varnish and coil and all these chemicals you're talking about. But, the wiping is a self-cleaning process.

MR. SPENCE: That's right. They were also silver to silver contacts. And they've since changed that out to silver-cadmium-oxide to help prevent some of that.

But what's interesting is some of the relays are in horizontal configurations, the shift is. And I was given three relays to take from River Bend up to Potter and Brumfield. Two of those relays. The first set of contacts up close and up top on the contact tech were bad. They weren't in service, you know, but if you think that the varnish and all these chemicals are going to go up, that's where they're going to condense.

And, sure enough, they didn't work.

MR. LINDBLAD: Okay.

MR. SPENCE: When they changed over to epoxy coating from the varnish coating, they also allowed some tramp epoxy in the area in here. And it wasn't cured and they put them in service and, sure enough, they locked up good and tight.

But, that's an early, you know, an early burn-in problem.

Another item which they found out is the shading coil. There's a copper shading coil in here on AC relays that is held on with a little couple dots of epoxy. The epoxy cracked because of the differential expansion.

They changed the material out last -- I think it was in '92 to copper beryllium to avoid that problem.

Contact continuity I think we've gotten some of the material problems. There's also application problems. You can't put -- these are very high amperage relays, you can't put them in low series, low amperages.

You can't parallel the set of contacts if you're trying to overload the relay, and so forth. That doesn't work.

There were -- with respect to radiation aging, one of the things that the manufacturer did was he put a little drop of grease here and here to try to help keep this thing working.

Well, that end-bell grease, come to find out, doesn't do terribly well in some radiation, and very high radiation areas. So they're not a 40-year life relay on that.

The lead wire insulation --

MR. LINDBLAD: Are there really applications where these relays are found in high radiation areas?

MR. SPENCE: Yes, there are. Susquehanna, for one.

MR. LINDBLAD: Is that right?

MR. SPENCE: Yes, sir. This came from their EQ report.

There's many factors --

MR. LINDBLAD: I'm sorry.

MR. SPENCE: Yes, sir.

MR. LINDBLAD: Is that a post-accident, or in normal operation?

MR. SPENCE: Post-accident.

MR. LINDBLAD: I understand that.

MR. SPENCE: There's many factors that affect when the relay is going to fail. You would think coil temperature would be one of them, but CE could not determine that for sure.

There's variation in the coil varnish, the thickness, composition. Different model numbers have different stacks of decks. Twenty-eight percent of the failures occurred in AC relays while 72 percent occurred in

D.C. relays.

Coil voltage is another item. Testing frequency. And testing frequency varies from one per month to once every 18 months.

Cabinet ventilation may be significant. And the position, horizontal or vertical mounting.

[Slide.]

MR. SPENCE: We took a look at trying to do some PRA on these failures. And we basically decided that given our situation we really couldn't. We had seen that there were eight solid simultaneous multiple failure events.

There were two more in which the licensee voluntarily replaced multiple relays after an event.

Dr. Zarn from Brook Haven indicated that with the population, with the number of relays that had failed, and so forth, he expected four failures to happen, multiple failures to happen simultaneously.

Instead, we got two to two and a half times that many.

We got five common mode failures, and five simultaneous multiple failures.

And, by that, I used this definition.

[Slide.]

MR. SPENCE: Where dependent failure is a failure that occurs based on the same cause, common cause is based on the same cause and the same time frame. Common mode is the same time frame, same cause to opposite, redundant components in the same system.

But the important thing here is this non-named area -- at least I couldn't find a name for it, so I invented one. I called it simultaneous multiple failure.

And that is where a component -- a relay fails at the same time for the same cause, but it's on a different system, or it's on the same system but not opposite trains.

And the importance of that is because of where these relay are located on all the actuation circuitry.

Yes, sir?

MR. DAVIS: You say simultaneous. But, earlier, you were talking an episode where there was an undetected earlier failure that appeared to be simultaneous with the later one.

Does your word "simultaneous" include an earlier, undetected failure?

MR. SPENCE: Yes. It would be that they're out of service at the same time whether it's detected or not detected, because these things are not always self-revealing. The shaft can go back and not reset.

MR. DAVIS: So, in one sense, it's parallel with people who rely on two check valves in series where you don't find out if both of them work until there's flow back through both of them.

MR. SPENCE: That's correct.

MR. DAVIS: That one can fail undetected, and then you're relying on the other.

MR. SPENCE: Right.

MR. DAVIS: So, in one sense, it's like that. And, what do we call that? Do you call that simultaneous multiple failure? I guess.

MR. SPENCE: Your normal PRAs do not model relays. They don't go into that detail.

MR. DAVIS: I think that there might be some confusion about that. PRAs do include relays in their models, and relay failures are accounted for in PRA.

I think what you're saying here is that PRAs do not model the internal workings of the relay and try to determine the failure modes for individual relays.

Is that --

MR. SPENCE: They don't try to determine the individual failure pass for the relay because in the trains of actuation logic, one relay may take out a pump and a valve and something else and, yet, higher up in the train, it will take out three trains of RHR and safety injection and containment spray, for example.

And that part, that actuation train is not modeled.

MR. DAVIS: I think it is modeled most of the time, but go ahead.

MR. SPENCE: The individual relays and exactly what they work, you know, is not. And that's where we have the problem. And, not only that, but when you have anywhere from one to 250 relays per plant, they're all in different locations.

So you have a problem trying to figure out what component is not working when.

MR. DAVIS: Okay.

MR. CARROLL: You've got to be very careful, Bob, about denigrating PRAs -- in Pete's presence.

MR. SPENCE: I apologize. I did not mean to --

[Laughter.]

MR. SPENCE: River Bend did do a PRA. They looked at their RPS system, and they found out that using their plant-specific failure data -- and they had two simultaneous failures out of four failures, and they used the beta factor on that -- they came out with an increased failure probability of 25 times as much.

So, not using PRA, we looked at it. We sliced and diced the data that we had to try to figure out what else we could learn from it.

[Slide.]

MR. SPENCE: B&W only had one out of -- one failure out of 12 relays for a failure rate of 8 percent, a little over 8 percent.

Combustion Engineering plants had a 7.5 percent failure rate. G.E., 3.6 percent. And, Westinghouse, 1 percent.

The big thing that I do not know is why this is so high and this is so low. I'm pretty sure what happened in here. And that is that Combustion Engineering plants had latching relays. They had trouble with their latching relays keeping them latched under certain circumstances.

They went ahead and they increased the coil voltage from 28 volts to 36 volts. That seemed to give a premature aging to that coil varnish, and they had a lot of lock-ups.

Okay. So I think that's part of this. Not all, but part.

The data, the 124 relays of failures, does not include seven that were independent failures from NPRDS data.

[Slide.]

MR. CARROLL In talking about NPRDS data, did you observe the quality of the data?

MR. SPENCE: Yes, I did.

MR. CARROLL: Did it improve with time?

MR. SPENCE: No, sir. In fact, there were things like a 40-year relay was failed in one year, and --

MR. CARROLL: No, no, no. The quality of the data.

MR. SPENCE: The quality of data.

MR. LANDBLAT: The reports that you saw.

MR. SPENCE: Do you mean more reports, or the quality of the explanations of it?

MR. SEALE: Yes. Was the data scrutable?

MR. CARROLL: Was the data getting more usable with time?

MR. SPENCE: No. I did not see that in this particular thing.

MR. CARROLL: Okay.

MR. SPENCE: We took a look at it as far as what was happening in each of these years. In 1988, it was when Combustion Engineering had the problems with their over-voltage situation, and they seemed to work themselves out of that.

If you look at a regression line going from '84 on up, it looks like this.

But, your error boundary is up here to zero. So that does not say too much. If you look at it for 1990, it is going up. If you look at it from back here, this thing is within one of where it is supposed to be.

The interesting thing that is happening is that there were six failure events, in 1991 and 1992, so that the multiple failure events is becoming significant.

We stopped in 1992, even though this study was issued at the end of '93, because the information on this was put out at the beginning of '92, and some of the people were starting to change out to relays.

So that the population was changing, and so you're now dealing with apples and oranges.

MR. CARROLL: The information notice recommendation was that people should periodically change these out?

MR. SPENCE: No. It did not say periodically.

What did we say, George? Do you remember?

MR. LANIK: I don't think it makes that kind of a recommendation at all about what they should do about it. You know, the information notice probably said that -- at least a couple of the events described the licensees did change them out.

MR. LINDBLAD: Change-out with replacement, same number or --?

MR. LANIK: With the later ones, with the improved epoxy in that.

MR. LINDBLAD: But not with a really fundamentally different --

MR. LANIK: No, I don't think so.

MR. LINDBLAD: In fact, this information notice required no specific action, or written response.

MR. CARROLL: Which is standard.

MR. SPENCE: You asked about NPRDS data, and I probably should have probably pulled the slide up at that point to tell you about it.

But I looked at the NPRDS data. This is generic relays, failure rates. This is the data that I got out of NPRDS, and this is failure rates, not exact numbers.

And what I found in my study -- and you can see it bounces all over the place. And if NPRDS data was supposed to get better in this period, I don't know. Judge for yourself.

MR. CARROLL: I'm not sure I understand your legend. Black is all NPRDS data?

MR. SPENCE: Yes. In other words, that is your average relay. Of all relays, yes.

MR. CARROLL: And the cross-hatch is just the Potter-Brumfield relays?

MR. SPENCE: Yes, based on NPRDS data. And the dotted one is what I learned by going out to the plants, as well as in addition to NPRDS.

MR. DAVIS: There still could be some theories that have never been reported or found.

MR. SPENCE: If it is any indication, when I went to Susquehanna they had 16 failures. I believe 12 of those or something to that magnitude were not reported to NPRDS.

MR. CARROLL: What is the explanation of that?

MR. SPENCE: I don't have one. It is a voluntary system.

MR. CARROLL: They should have been reported in your opinion?

MR. SPENCE: Some of them should be, yes, should have been.

MR. CARROLL: Okay.

[Slide.]

MR. SPENCE: We took a look at the failure rate by unit and if you say, okay, these are burn-in type things and you discount them, it kind of clusters in this area so that basically if you've got 100 relays, you can expect one failure in a unit per year with the old relays.

[Slide.]

MR. CARROLL: When you say old you mean the varnish?

MR. SPENCE: Yes, the varnished ones that were made before May of 1990 but actually they came up in '92 because they were still changing things then.

We took a look at the service line because that varied so much. Let me get out of order here a little bit and explain that. I'll go to Slide Number 14 for a second.

If you look at when these relays came into service there is quite a difference. If you read this graph -- this is 1984 and this is 1992 -- so that 1992 there were 3,000 of them in service and in 1984 there were about 750, something like that, and I have got it split up here -- the CE plants and the B&W plants. So there is a larger curve, higher sloped curve on the B&W, GE, and Westinghouse plants than there is on the CE and I think this is part of it.

If you look back at three or four years you are seeing that the CE plants are now coming up to full capacity on those relays, if you will, whereas the other units are still growing, so with that in mind and because there is such a difference in the number of relays, we took at a look at the statistics based on service, time and service.

[Slide.]

MR. SPENCE: This shows the different ones where you get Combustion Engineering and of course Black having the most and as I was saying in the three to five year service life that is kind of an aging effect of the coil over-voltage.

The Westinghouse unit's coming on a little bit stronger in the past; part of this is replacement of relays.

MR. LINDBLAD: But this data is not normalized to the number in service. This is just the raw count?

MR. SPENCE: That is just the raw count, this one is.

MR. LINDBLAD: You showed on the previous slide that there was substantial slope to the application rate.

MR. SPENCE: Right. The next slide will get into the rates.

MR. LINDBLAD: Thank you.

MR. SPENCE: This is just the raw count.

[Slide]

MR. SPENCE: If you take a look at it on the rates it shows a little bit different picture. If you try to run statistics on this, you get something in this area here depending if you look at it from here you are going up-hill. I also -- and it is much more interesting when you take a look at it based on the particular plants.

[Slide.]

MR. SPENCE: You get a lot of burn-ins from the over-voltage situation and then it pretty well stabilizes out for CE plants. Most of the CE plants, Palo Verde, San Onofre, Waterford III, Arkansas Nuclear I have changed out at least once their set of relays.

If you look at what is happening at the other plants, I have no explanation for this whatsoever.

[Slide.]

MR. SPENCE: It is up here, if you take averages, maybe up here --

MR. LINDBLAD: Let me look at the legend again. This is the number of failures per year per relay installed and there are whole numbers over on the left?

MR. SPENCE: No, sir. This is .00025, okay?

MR. LINDBLAD: All right, all right.

MR. SPENCE: And it is a failure rate.

MR. LINDBLAD: Okay, thank you.

[Slide.]

MR. SPENCE: Conclusions -- we put out our Information Notice 92-04. There was also 92-19 that addressed this and we put together this study. This study came out in December of last year.

That study suggested a supplement to the information notice of January of '92. We are going to change this study into a NUREG format and get it out for a little bit wider distribution and overseas distribution as well.

That is about all I have, gentlemen.

MR. CARROLL: Okay.

MR. DAVIS: Let me ask a couple of questions, if I might.

It is not clear to me now what the Licensee needs to do in response to this problem. Can he still operate a plant with these relays and safety-systems?

MR. SPENCE: They are doing it all the time.

MR. DAVIS: That is troubling to me. Some of these failures were particularly significant in terms of their effect on important safety systems and the common mode aspect is also troubling.

MR. SPENCE: It is encouraging to note that people like -- like I said, the CE plants have, are changing them out and so forth. To a large part Susquehanna is, River Bend is. The ones with the 200 number of relays are pretty much changing them out.

I do not know what the smaller plants --

MR. DAVIS: These are all voluntary?

MR. CARROLL: Yes, and have we had enough experience with the modified relays to be satisfied that there is not some problem with them?

MR. SPENCE: There have been some manufacturing problems obviously. There has to be very good receipt inspection and testing by the utilities to make sure that they have got good relays because now these are commercial grade items.

Combustion Engineering had to go to the point of putting them in directly on the manufacturing process line to make sure that they got quality and Potter-Brumfield supplied a complete new batch free for Waterford III.

MR. LINDBLAD: These are analog control elements that ought to be backed up by semiconductors.

MR. CARROLL: That sounds reasonable to me. We are adopting that on new plants.

MR. DAVIS: The other thing that seems a little troubling to me is a lot of these failures occurred -- there were a lot of failures, what we refer to as "infant failures" when the units were first installed, but it doesn't seem like that drew anybody's attention or caused any concern at the time.

MR. SPENCE: That's correct. Back to what I was saying. They throw them in the can; they throw relays in the can --

MR. DAVIS: And put in the same one again.

MR. SPENCE: Yes. I think there is enough information out on the street now -- I will not say that because I know of a situation where they failed and they did not really check it out, but I think for the most part people are sensitive to Potter-Brumfield, MDR having a problem. Potter-Brumfield has also got problems with another -- I think it is an R-10 series that was a Part 21, there was a Part 21 just put in on those and then the branches looked at that.

MR. CARROLL: Did they file a Part 21 on these?

MR. SPENCE: Potter-Brumfield? They have never filed a Part 21 to my knowledge. When a member of Vendor

Inspection Branch and I went out to visit the manufacturing facility, he hit them with a violation for not filing, for not going along with Part 21. Part 21s that we have gotten, there's a couple I believe from GE and Combustion Engineering but unfortunately they only looked at it like a narrow issue.

For example, when the Combustion Engineering plants were having problems and it was high voltage, they attributed the cause to that, and you look at the data and it is there anyway. That was just premature.

MR. CARROLL: Any other questions or observations?

[No response.]

MR. CARROLL: Okay, well that was a very good presentation, Bob.

MR. DAVIS: I found your December 1993 report very good in terms of completeness. I had a little quarrel with some of your PRA definitions but I usually find that to be the case.

MR. CARROLL: Pete and I then turn this back to you, Mr. Chairman.

MR. KRESS: What do I do with the extra time you gave me?

[Pause.]

MR. CARROLL: Close the record, the transcript.

MR. KRESS: We want to close the transcript now, please.

[Whereupon, at 1:50 p.m., the open portion of the meeting was adjourned.]

REPORTER'S CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

NAME OF PROCEEDING: 410th ACRS Meeting

DOCKET NUMBER:

PLACE OF PROCEEDING: Bethesda, MD

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

Barbara Whitlock

Official Reporter
Ann Riley & Associates, Ltd.

T-1,2,3,4,5,6

NRC STAFF ACTIVITIES ON
MOTOR-OPERATED VALVES AND CHECK VALVES

JUNE 10, 1994

THOMAS G. SCARBROUGH
MECHANICAL ENGINEERING BRANCH
DIVISION OF ENGINEERING
OFFICE OF NUCLEAR REACTOR REGULATION

REGULATORY BASIS FOR ADEQUATE MOV PERFORMANCE

NRC REQUIRES THAT SAFETY-RELATED MOVs BE DESIGNED, MANUFACTURED, INSTALLED, TESTED, AND MAINTAINED TO BE ABLE TO PERFORM THEIR SAFETY FUNCTIONS.

EXAMPLES OF APPLICABLE CRITERIA IN APPENDIX B TO 10 CFR PART 50 ARE:

- CRITERION III, DESIGN CONTROL
- CRITERION V, INSTRUCTIONS, PROCEDURES, AND DRAWINGS
- CRITERION XI, TEST CONTROL
- CRITERION XII, CONTROL OF MEASURING AND TEST EQUIPMENT
- CRITERION XVI, CORRECTIVE ACTION

GENERIC LETTER 89-10
SAFETY-RELATED MOTOR-OPERATED VALVE TESTING AND SURVEILLANCE
(JUNE 28, 1989)

GL 89-10 REQUESTED LICENSEES TO ESTABLISH PROGRAMS TO ENSURE CAPABILITY OF ALL MOVs IN SAFETY-RELATED SYSTEMS TO PERFORM THEIR SAFETY FUNCTION.

INDIVIDUAL RECOMMENDED ACTIONS:

A. REVIEW AND DOCUMENT THE DESIGN BASIS FOR THE OPERATION OF EACH MOV.

B. REVIEW AND REVISE METHODS FOR SELECTING AND SETTING MOV SWITCHES.

C. TEST MOVs AT DESIGN-BASIS DIFFERENTIAL PRESSURE AND FLOW CONDITIONS WHERE PRACTICABLE AND JUSTIFY ALTERNATIVES WHERE DESIGN-BASIS TESTING IS NOT PRACTICABLE.

D. VERIFY ADEQUATE SWITCH SETTINGS PERIODICALLY (EVERY 5 YEARS OR 3 REFUELING OUTAGES, AND FOLLOWING MAINTENANCE).

E. ANALYZE EACH MOV FAILURE, JUSTIFY CORRECTIVE ACTION, AND TREND RESULTS (WITH REVIEW EVERY 2 YEARS).

SCHEDULE:

COMPLETE INITIAL TEST PROGRAM BY JUNE 28, 1994, OR 3 REFUELING OUTAGES AFTER DECEMBER 28, 1989, WHICHEVER IS LATER.

SUPPLEMENT 1 TO GENERIC LETTER 89-10
(JUNE 13, 1990)

PROVIDES THE RESULTS OF THE PUBLIC WORKSHOPS TO DISCUSS THE GENERIC LETTER AND TO ANSWER QUESTIONS REGARDING ITS IMPLEMENTATION.

LIMITS SCOPE OF GENERIC LETTER TO MOVs IN SAFETY-RELATED <u>PIPING</u> SYSTEMS.

LIMITS CONSIDERATION OF VALVE MISPOSITIONING TO INADVERTENT OPERATION FROM THE CONTROL ROOM.

DISCUSSES THE FACTORS TO BE CONSIDERED, AND LIMITATIONS, IN JUSTIFYING THE ACCEPTABILITY OF ALTERNATIVES TO IN SITU DESIGN-BASIS TESTING.

EMPHASIZES THE RECOMMENDATION TO FOLLOW THE TWO-STAGE APPROACH WHERE DESIGN-BASIS TESTING IS NOT PRACTICABLE AND AN ALTERNATIVE CANNOT BE JUSTIFIED AT THIS TIME.

SUPPLEMENT 2 TO GENERIC LETTER 89-10
(AUGUST 3, 1990)

TO ALLOW ADDITIONAL TIME FOR LICENSEES TO INCORPORATE THE INFORMATION IN SUPPLEMENT 1 INTO THEIR GENERIC LETTER PROGRAMS, THE NRC STAFF STATED THAT PROGRAM DESCRIPTIONS DID NOT NEED TO BE AVAILABLE ON SITE UNTIL JANUARY 1, 1991.

THE SCHEDULE REQUESTED FOR COMPLETING THE RECOMMENDED ACTIONS OF GL 89-10 BY JUNE 28, 1994 OR THREE REFUELING OUTAGES AFTER DECEMBER 28, 1989 (OR OPERATING LICENSE ISSUANCE FOR CONSTRUCTION PERMIT HOLDERS) REMAINED UNCHANGED.

SUPPLEMENT 3 TO GENERIC LETTER 89-10
(OCTOBER 25, 1990)

BASED ON (1) THE RESULTS OF NRC-SPONSORED MOV TESTS UNDER GENERIC ISSUE 87 OF 6-INCH AND 10-INCH FLEXIBLE WEDGE GATE VALVES TYPICALLY USED FOR CONTAINMENT ISOLATION IN THE HIGH PRESSURE COOLANT INJECTION (HPCI) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEMS AND IN THE SUPPLY LINE FOR THE REACTOR WATER CLEANUP (RWCU) SYSTEM IN BWR PLANTS, AND (2) THE NRC STAFF'S BRIEF REVIEW OF THE CAPABILITY OF MOVs USED FOR THOSE PURPOSES AT BWR PLANTS, THE STAFF DETERMINED THAT ACTION SHOULD BE TAKEN BY BWR LICENSEES TO PROVIDE ASSURANCE OF THE CAPABILITY OF THOSE MOVs IN ADVANCE OF THE OVERALL GENERIC LETTER SCHEDULE.

IN RESPONSE TO SUPPLEMENT 3, BWR LICENSEES ESTABLISHED CRITERIA TO DETERMINE WHETHER DEFICIENCIES EXISTED IN THE APPLICABLE MOVs IN THE HPCI, RCIC, AND RWCU SYSTEMS, AS WELL AS IN THE ISOLATION CONDENSER LINES, AS APPLICABLE; IDENTIFIED ANY MOVs FOUND TO HAVE DEFICIENCIES; AND ESTABLISHED A SCHEDULE FOR ANY NECESSARY CORRECTIVE ACTION.

BWR LICENSEES PERFORMED EVALUATIONS IN RESPONSE TO SUPPLEMENT 3 TO GL 89-10.

LICENSEES REPORTED THAT APPROXIMATELY ONE-HALF OF THE 200 MOVs WITHIN THE SCOPE OF SUPPLEMENT 3 TO GL 89-10 HAD BEEN, OR WOULD BE, MODIFIED OR ADJUSTED IN RESPONSE TO THE EVALUATION PERFORMED IN RESPONSE TO SUPPLEMENT 3.

SUPPLEMENT 4 TO GENERIC LETTER 89-10
(FEBRUARY 12, 1992)

BWR OWNERS GROUP APPEALED THE RECOMMENDATION IN GL 89-10 TO ADDRESS INADVERTENT MOV OPERATION FROM THE CONTROL ROOM.

AS RESULT OF AN NRC-SPONSORED STUDY OF CORE MELT PROBABILITY, NRC STAFF ISSUED SUPPLEMENT 4 TO GL 89-10 STATING THAT BWR LICENSEES NEED NOT ADDRESS INADVERTENT MOV OPERATION AS PART OF THEIR GL 89-10 PROGRAMS ALTHOUGH THE STAFF BELIEVES THAT SUCH CONSIDERATION BENEFITS SAFETY.

SUPPLEMENT 4 EMPHASIZED THAT LICENSEES MAY NEED TO ADDRESS VALVE MISPOSITIONING IN RESPONSE TO NRC REGULATIONS (SUCH AS FIRE PROTECTION).

SUPPLEMENT 5 TO GENERIC LETTER 89-10
(JUNE 28, 1993)

ON FEBRUARY 4, 1992, MOV USERS GROUP ISSUED REPORT ON ACCURACY OF MOV DIAGNOSTIC EQUIPMENT AND FOUND EQUIPMENT FROM IMPELL AND ITI-MOVATS RELYING ON SPRING PACK DISPLACEMENT TO ESTIMATE STEM THRUST DID NOT MEET THEIR ACCURACY CLAIMS. ON MARCH 2, 1992, STAFF MET WITH ITI-MOVATS TO DISCUSS MUG PROGRAM AND ITI-MOVATS VALIDATION PROGRAM. ITI-MOVATS FOUND INCREASED UNCERTAINTY IN ACCURACY OF THRUST MEASURING DEVICE (TMD) FROM CALIBRATION IN OPEN DIRECTION WHILE RELYING ON TMD TO ESTIMATE THRUST IN CLOSE DIRECTION. ON MARCH 13, 1992, ITI-MOVATS RELEASED ENGINEERING REPORT 5.2 TO PROVIDE GUIDANCE FOR LICENSEES. NUMARC PREPARED GUIDELINES ON ITI-MOVATS GUIDANCE.

ON OCTOBER 2, 1992, LIBERTY TECHNOLOGIES SUBMITTED A PART 21 NOTICE ON THE POTENTIAL INCREASED INACCURACY OF ITS VOTES EQUIPMENT CAUSED BY (1) THE POSSIBLE USE OF IMPROPER STEM MATERIAL CONSTANTS AND (2) THE FAILURE TO ACCOUNT FOR A TORQUE EFFECT WHEN THE EQUIPMENT IS CALIBRATED BY MEASURING STRAIN OF THE THREADED PORTION OF A VALVE STEM. INFORMATION NOTICE 93-01 DISCUSSED THE INCREASED INACCURACY OF THE VOTES EQUIPMENT.

LICENSEES WERE REQUIRED TO NOTIFY THE NRC STAFF OF THEIR MOV DIAGNOSTIC EQUIPMENT AND TO REPORT ACTIONS TAKEN OR PLANNED (INCLUDING SCHEDULE) TO ADDRESS THE INFORMATION ON THE ACCURACY OF MOV DIAGNOSTIC EQUIPMENT.

STAFF HAS REVIEWED THE LICENSEE RESPONSES TO SUPPLEMENT 5. NRC INSPECTIONS WILL ADDRESS SPECIFIC ASPECTS OF LICENSEE ACTIONS TO ADDRESS MOV DIAGNOSTIC EQUIPMENT INACCURACY.

SUPPLEMENT 6 TO GL 89-10
(MARCH 8, 1994)

FEBRUARY 1993 - NRC STAFF HELD PUBLIC WORKSHOP TO DISCUSS GL 89-10 AND TO ANSWER QUESTIONS ON ITS IMPLEMENTATION

SUPPLEMENT 6 CONTENTS:

SCHEDULE EXTENSIONS

LICENSEES PLANNING TO EXTEND THEIR GL 89-10 SCHEDULES ARE REQUIRED TO SUBMIT INFORMATION THAT JUSTIFIES SCHEDULE EXTENSION.

EVEN IF GL 89-10 SCHEDULE EXTENDED, LICENSEES EXPECTED TO HAVE MOVs SET UP WITH THE BEST AVAILABLE INDUSTRY DATA BY ORIGINAL COMPLETION DATE ACCEPTED BY THE STAFF.

IF GL 89-10 SCHEDULE TO BE EXTENDED, REPORTING REQUIREMENTS ARE:

(1) COMPLETION STATUS OF PROGRAM,

(2) FOR MOVs WHOSE CAPABILITY WILL NOT BE VERIFIED BY DYNAMIC TESTING BY CURRENT COMMITMENT DATE:

   (A) VALVE SPECIFIC DATA AND CAPABILITY MEASURE;

   (B) CONFIRMATION OF MOV FUNCTIONALITY USING BEST AVAILABLE INFORMATION; AND

   (C) SCHEDULE FOR COMPLETING TESTING AND CORRECTIVE ACTION.

GROUPING OF MOVs

STAFF CONTINUES TO RECOMMEND TESTING MOVs UNDER DESIGN-BASIS CONDITIONS WHERE PRACTICABLE. HOWEVER, GROUPING TO REDUCE MOV TESTING MAY BE ACCEPTABLE UNDER CERTAIN CONDITIONS.

IMPORTANT CONSIDERATIONS FOR GROUPING:

(1) VERIFICATION OF DESIGN ADEQUACY THROUGH REVIEW AND ANALYSIS OF INDUSTRY AND PLANT-SPECIFIC DATA,

(2) USE OF DATA FROM 30% SAMPLE (2 MINIMUM),

(3) STATIC DIAGNOSTIC TESTING OF EACH MOV,

(4) SELECTION OF VALVES FOR DYNAMIC TESTING BASED ON PRIORITIZATION,

(5) VALIDATION OF DESIGN-BASIS ASSUMPTIONS,

(6) CONSIDERATION AND DOCUMENTATION OF SIMILARITIES, AND

(7) IF MOV FAILS, EVALUATION OF ALL MOVs IN GROUP.

ENCLOSURE TO SUPPLEMENT 6 INCLUDES

(1) USE OF PROBABILISTIC RISK ASSESSMENT IN IMPLEMENTING GL 89-10

(2) KALSI REPORT ON OVERTHRUST CAPABILITY,

(3) TEST ACCEPTANCE CRITERIA,

(4) DEGRADED VOLTAGE EVALUATION, AND

(5) PRESSURE LOCKING AND THERMAL BINDING.

TEMPORARY INSTRUCTION 2515/109

TEMPORARY INSTRUCTION (TI) 2515/109 WAS DEVELOPED FOR TWO DISTINCT INSPECTIONS OF THE GL 89-10 PROGRAM AT EACH NUCLEAR POWER PLANT.

PART 1

PART 1 OF TI 2515/109 PROVIDES GUIDANCE FOR AN INSPECTION TO REVIEW THE PROGRAM DEVELOPED IN RESPONSE TO GL 89-10.

NRC STAFF CONDUCTED INSPECTIONS IN ACCORDANCE WITH PART 1 (PROGRAM REVIEW) OF THE TI AT EACH PLANT WITH EXCEPTION OF MILLSTONE (SELF-ASSESSMENT WHICH NRC STAFF MONITORED).

RESULTS OF THE INSPECTIONS UNDER PART 1 OF THE TI ARE SUMMARIZED IN INFORMATION NOTICE 92-17.

PART 2

PART 2 OF THE TI PROVIDES GUIDANCE FOR AN INSPECTION OF THE IMPLEMENTATION OF THE GL 89-10 PROGRAM.

IN FEBRUARY 1993, NRC INITIATED INSPECTIONS USING PART 2 OF TI 2515/109 AND HAS CONDUCTED OVER 30 PART 2 INSPECTIONS TO DATE.

ON APRIL 30, 1993, NRR PROVIDED A MEMORANDUM TO THE REGIONS WHICH INCLUDED INSPECTION GUIDANCE DEVELOPED JOINTLY BY THE REGIONS AND NRR.

REVISION 1 TO TI 2515/109 WAS ISSUED ON JUNE 14, 1993, TO REFLECT THE RESULTS OF THE PART 1 INSPECTIONS, THE WORKSHOP ON JANUARY 12 TO 14, 1993, AND A MANAGEMENT MEETING IN APRIL 1993. REVISION 1 TO TI 2515/109 REFERENCES THE APRIL 30 MEMORANDUM FOR INSPECTION GUIDANCE.

SUPPLEMENT 6 TO GL 89-10 PROVIDES ADDITIONAL INFORMATION TO ASSIST INSPECTORS IN PERFORMING INSPECTIONS OF GL 89-10 PROGRAMS.

IN 1995, NRR PLANS TO REPLACE THE TI WITH AN INSPECTION PROCEDURE MODULE.

RESULTS OF INSPECTIONS OF GL 89-10 PROGRAMS

SCOPE

* CONSISTENT WITH GL 89-10
* MOST PWR LICENSEES DEFERRING VALVE MISPOSITIONING

DESIGN-BASIS REVIEW

* APPROPRIATE PLANT DOCUMENTATION REVIEWED TO DETERMINE DESIGN-BASIS CONDITIONS
* SOME DESIGN-BASIS PARAMETERS NOT ADEQUATELY ADDRESSED
* SOME DEGRADED VOLTAGE STUDIES NEEDED UPDATING
* WEAKNESS IN EVALUATION OF PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES

MOV SIZING AND SWITCH SETTING

* SOME UTILITIES UPDATED VALVE FACTORS BUT OTHERS USED PREVIOUS VENDOR GUIDANCE
* VALIDATION OF ASSUMPTIONS FOR VALVE FACTOR, STEM FRICTION COEFFICIENT AND LOAD-SENSITIVE BEHAVIOR NEEDED IMPROVEMENT

INSPECTION RESULTS
(CONTINUED)

DESIGN-BASIS CAPABILITY TESTING

* DIFFERENTIAL PRESSURE AND FLOW TESTING REVEALED MANY GATE VALVES, AND SOME GLOBE AND BUTTERFLY VALVES, TO REQUIRE MORE THRUST AND TORQUE TO OPERATE THAN PREDICTED BY VENDORS.

* MOST SIGNIFICANT INSPECTION CONCERNS ON MOV TESTING WERE:

  LACK OF DYNAMIC TEST PROGRESS,
  WEAKNESS IN PROCEDURES AND ACCEPTANCE CRITERIA, AND
  LACK OF FEEDBACK OF TEST RESULTS.

* MOV TEST ACTIVITIES NEEDING IMPROVEMENT INCLUDED:

  JUSTIFICATION FOR MOV GROUPING,
  VERIFICATION OF EXTRAPOLATION OF TEST DATA,
  EVALUATION OF TRACE ANOMALIES, AND
  INVOLVEMENT OF QUALITY ASSURANCE PERSONNEL.

* ATTENTION TO REGULATORY REQUIREMENTS AND TECHNICAL SPECIFICATIONS NEEDED FOR REPORTING AND ACTION BASED ON TEST RESULTS.

INSPECTION RESULTS
(CONTINUED)

PERIODIC VERIFICATION AND POST-MAINTENANCE TESTING

* NO UTILITY HAD JUSTIFIED ITS METHOD FOR PERIODIC VERIFICATION OF DESIGN-BASIS CAPABILITY

* POST-MAINTENANCE TESTING IMPROVEMENTS

CORRECTIVE ACTION AND TRENDING

* ANALYSIS OF MOV PROBLEMS NOT ALWAYS THOROUGH

* LITTLE PROGRESS IN IMPLEMENTING TRENDING PROGRAMS

TRAINING

* SIGNIFICANT IMPROVEMENTS IN TRAINING PROGRAMS

SCHEDULE

* SOME UTILITIES HAD NOT MADE ADEQUATE PROGRESS TO COMPLETE GL 89-10 PROGRAM

RECENT EXAMPLES OF TYPICAL MOV PROBLEMS AND CAUSES

DESIGN AND QUALIFICATION

* UNDERESTIMATION OF THRUST AND TORQUE REQUIREMENTS

VALVE FRICTION FOR GATE VALVES

April 1993 - Two AFW discharge cross-connect MOVs at Kewaunee failed to close under dynamic testing. Motor actuators undersized.

June 1993 - River Bend RHR MOV failed to fully close during dynamic testing.

August 1993 - Millstone Unit 2 declared PORV block MOVs inoperable when EPRI test data revealed that the MOVs would not be able to close under 2250 psid design-basis differential pressure.

September 1993 - At Prairie Island, Powell eight-inch and ten-inch solid wedge gate valves found during testing to have valve factors (0.49 to 0.93 using orifice area) in excess of the thrust values assumed by the manufacturer.

November 1993 - Palo Verde Unit 1 determined that design-basis capability of several MOVs was questionable and that the MOVs had been inoperable prior to GL 89-10 program.

November 1993 - RHR System "A" loop injection valve at Peach Bottom Unit 3 failed to fully close. Unit 3 shut down because valve repairs required closure of manual valve inside the drywell.

December 1993 - Prairie Island Unit 2 discovered higher than expected valve factors for two ALOYCO 8-inch double disk wedge gate valves.

December 1993 - Millstone determined that the RWCU isolation valves might not have adequate closing capability under dynamic conditions. The MOVs declared inoperable and closed.

December 1993 - Haddam Neck declared 4 feedwater isolation valves inoperable due to inadequate torque available for a design basis accident. Engineering evaluation showed the MOVs to have available thrust less than 0.3 valve factor.

December 1993 - Fermi-2 recirculation pump discharge valve failed to fully close while placing RHR system into shutdown cooling mode of operation.

March 1994 - Two HPCI MOVs at Dresden Unit 3 and a RCIC MOV at Quad Cities Unit 1 were declared inoperable when analysis showed that these MOVs might not operate under their design-basis conditions in light of EPRI test results.

VALVE FRICTION AND FLOW AREA FOR GLOBE VALVES

DECEMBER 1993 - INFORMATION NOTICE 93-88 REPORTED THAT EPRI HAD FOUND SOME GLOBE VALVE THRUST REQUIREMENTS GREATER THAN PREDICTED BY VENDOR.

JANUARY 1994 - BORG-WARNER MADE A PART 21 NOTIFICATION THAT GLOBE VALVE THRUST USED FOR ACTUATOR SIZING MIGHT BE LESS THAN ACTUAL REQUIRED THRUST BASED ON EPRI TESTING.

STEM FRICTION COEFFICIENT FOR GATE AND GLOBE VALVES

1993 AND 1994 - SOME LICENSEES HAVE BEEN UNABLE TO JUSTIFY THE OPTIMISTIC STEM FRICTION COEFFICIENT OF 0.15 BASED ON PLANT-SPECIFIC DATA.

TORQUE REQUIREMENTS TO OPERATE BUTTERFLY VALVES

FEBRUARY 1993 - BUTTERFLY MOV IN THE SERVICE WATER SYSTEM AT CATAWBA FAILED TO OPERATE UNDER DYNAMIC CONDITIONS BECAUSE OF INADEQUATE PREDICTION OF TORQUE REQUIREMENTS. LICENSEE FOUND DEFICIENCY APPLICABLE TO OTHER SERVICE WATER BUTTERFLY MOVS AND SERVICE WATER SYSTEM INOPERABLE SINCE AUGUST 1992.

FEBRUARY 1994 - SIX ESSENTIAL SERVICE WATER SYSTEM BUTTERFLY MOVS AT BYRON WERE FOUND TO POTENTIALLY NOT HAVE SUFFICIENT TORQUE CAPABILITY FOR DESIGN-BASIS CONDITIONS AT THEIR TORQUE SWITCH SETTINGS.

DESIGN-BASIS DIFFERENTIAL PRESSURE

SEPTEMBER 1990 - BYRON AND BRAIDWOOD DETERMINED THAT 32 MOVS IN AFW SYSTEMS MAY NOT BE CAPABLE OF CLOSING UNDER DESIGN-BASIS CONDITIONS BECAUSE OF INCORRECT DIFFERENTIAL PRESSURE ASSUMPTION.

APRIL 1992 - CRYSTAL RIVER DETERMINED THAT ASSUMED DIFFERENTIAL PRESSURE FOR FOUR EFW MOVS WAS INADEQUATE AND THEY SUBSEQUENTLY FAILED DYNAMIC TESTING.

* OVERESTIMATION OF MOTOR ACTUATOR OUTPUT

DESIGN-BASIS MINIMUM VOLTAGE

JULY 1993 - CRYSTAL RIVER UNIT 3 DECLARED A HPCI MOV INOPERABLE WHEN DISCREPANCY IDENTIFIED BETWEEN THE ACCEPTANCE CRITERIA FOR ELECTRICAL BRAKE MINIMUM OPERATING VOLTAGE AND MOTOR MINIMUM VOLTAGE. SIX OTHER MOVS WERE FOUND WITH THIS CONDITION.

SEPTEMBER 1993 - FORT CALHOUN IDENTIFIED POWER CABLES FOR FIVE MOVS INADEQUATELY SIZED FOR LOCKED-ROTOR CURRENT.

SEPTEMBER 1993 - MILLSTONE UNIT 2 SHUT DOWN WHEN 4 FEEDWATER ISOLATION MOVS FOUND TO BE INOPERABLE BECAUSE OF LACK OF ASSURANCE THAT MOTOR BRAKES WOULD RELEASE TO ALLOW MOTOR OPERATION UNDER DEGRADED VOLTAGE CONDITIONS. ALSO, FITZPATRICK LICENSEE FOUND 2 LPCI MOVS TO HAVE UNDERSIZED MOTOR BRAKES THAT WOULD NOT PREVENT SPRING PACK RELAXATION AND MOTOR RESTART.

SEPTEMBER 1993 - PILGRIM DECLARED HPCI STEAM LINE ISOLATION MOV (AND HPCI SYSTEM) INOPERABLE BECAUSE OF INSUFFICIENT THRUST CAPABILITY WHEN LICENSEE DETERMINED FROM LIMITORQUE THAT RUN EFFICIENCY SHOULD NOT BE USED FOR DC-POWERED MOVs. LICENSEE MODIFIED GEARING TO OBTAIN ADEQUATE THRUST CAPABILITY.

OCTOBER 1993 - DUANE ARNOLD DECLARED HPCI INOPERABLE WHEN THE HPCI STEAM SUPPLY MOV TRIPPED ITS BREAKER AFTER THE VALVE WAS COMPLETELY CLOSED, DUE TO AN INAPPROPRIATE TORQUE SWITCH SETTING.

NOVEMBER 1993 - NINE MILE POINT UNIT 2 DECLARED A HPCS INJECTION VALVE AND HPCS SYSTEM INOPERABLE WHEN MOV FAILED TO OPEN DURING TESTING. FAILURE RESULTED FROM MOTOR CONTACTOR BEING UNABLE TO ACTUATE DUE TO INSUFFICIENT CONTROL VOLTAGE. SPECIFICATION INDICATED THAT STARTING COIL REQUIRED 80% VOLTAGE.

AMBIENT TEMPERATURE EFFECTS ON MOTOR TORQUE OUTPUT

MAY 1993- LIMITORQUE MADE PART 21 NOTIFICATION THAT HIGH AMBIENT TEMPERATURE CAN SIGNIFICANTLY REDUCE THE OUTPUT OF AC MOTORS.

LOAD SENSITIVE BEHAVIOR

DECEMBER 1992 - DAVIS BESSE UNIT 1 DETERMINED THAT LOAD SENSITIVE BEHAVIOR (REDUCED THRUST OUTPUT UNDER DYNAMIC CONDITIONS) MIGHT HAVE PREVENTED 2 MOVs FROM PERFORMING THEIR SAFETY FUNCTIONS.

* STRUCTURAL CAPABILITY OF MOV COMPONENTS

  AUGUST 1993 - INDIAN POINT 3 DECLARED SIX MOVS IN COMPONENT COOLING AND RHR SYSTEMS INOPERABLE BECAUSE OF OVERTHRUSTED VALVE YOKES AND WEDGES.

  OCTOBER 1993 - CRACKS FOUND IN VALVE YOKES OF SEVERAL WALWORTH VALVES AT PEACH BOTTOM UNITS 2 AND 3.

  OCTOBER 1993 - DURING TESTING OF HPCS INJECTION VALVE AT CLINTON, LICENSEE DISCOVERED MOTOR PINION KEY BROKEN.

  NOVEMBER 1993 - AT GRAND GULF, HPCS TEST RETURN LINE ISOLATION VALVE TO THE CST FAILED WHEN VALVE WAS STROKED CLOSED. LICENSEE DETERMINED THAT THE YOKE BROKE WHEN VALVE WAS CLOSED FOR STROKE TIME TESTING.

  MARCH 1994 - A TORQUE SWITCH ROLL-PIN FAILED IN AN MOV AT PILGRIM. LIMITORQUE MADE A PART 21 NOTIFICATION ON TORQUE SWITCH ROLL-PIN FAILURE IN LARGE ACTUATORS. SIMILAR FAILURES HAVE OCCURRED AT HOPE CREEK, WNP-2 AND PALO VERDE.

* POTENTIAL PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES

  FEBRUARY 1993- LASALLE UNIT 1 REPORTED THAT THE INBOARD ISOLATION MOV IN THE RCIC STEAM LINE FAILED IN THE CLOSED POSITION ON FEBRUARY 10 AND 26 FOLLOWING ITS CLOSURE FOR ROUTINE MAINTENANCE WITH THE CAUSE DETERMINED TO BE PRESSURE LOCKING.

MAINTENANCE AND TRAINING

APRIL 1993 - SERVICE WATER TRAIN "A" COOLING TOWER PUMP DISCHARGE BUTTERFLY MOV AT SEABROOK FAILED TO CLOSE DURING SURVEILLANCE TESTING BECAUSE OF CORROSION BUILDUP BETWEEN VALVE STEM AND PACKING FOLLOWER. THREE PUMPS IN SW TRAIN "A" WILL NOT START AUTOMATICALLY UNLESS MOV CLOSED; THEREFORE, LICENSEE DECLARED PUMPS INOPERABLE. MOV CLOSED MANUALLY.

JUNE 1993 - RCIC TURBINE EXHAUST VACUUM BREAKER STOP MOV AT LASALLE UNIT 2 WOULD NOT CLOSE DURING SURVEILLANCE TESTING WHEN THERMAL OVERLOAD TRIPPED WITH CAUSE BELIEVED TO BE HARDENING OF VALVE PACKING OR STEM LUBRICANT.

JULY 1993 - DURING PERFORMANCE TEST, PERRY DISCOVERED THAT THE MOV BETWEEN THE NONSAFETY-RELATED NUCLEAR CLOSED COOLING WATER SYSTEM AND THE SAFETY RELATED EMERGENCY CLOSED COOLING WATER SYSTEM SUPPLY WAS NOT FULLY CLOSED AS INDICATED AND WAS LEAKING IN EXCESS OF 250 GPM. LICENSEE DETERMINED THAT THE VALVE WAS TRAVELING PAST ITS SEAT AND THAT THE LIMIT SWITCH AND STOP NUT HAD NOT BEEN SET CORRECTLY.

AUGUST 1993 - HPCI MOV AT COOPER FAILED TO OPEN DURING SURVEILLANCE TESTING WHEN MOTOR PINION KEY FELL OUT. LICENSEE DECLARED HPCI SYSTEM INOPERABLE. LICENSEE FOUND THE END OF MOTOR SHAFT HAD NOT BEEN STAKED AND MOTOR SHAFT NOT COUNTERBORED FOR SET SCREW.

OCTOBER 1993 - DURING SURVEILLANCE TESTING OF RECIRCULATION SPRAY PUMP SYSTEM, BEAVER VALLEY DISCOVERED VALVE DISC DISENGAGED FROM THE ACTUATOR OF A BUTTERFLY VALVE. DEFECT FOUND ON FOUR BUTTERFLY MOVS SUPPLIED BY THE HENRY PRATT COMPANY.

November 1993 - TMI-1 made modifications to manual declutch levers on two MOVs to correct a seismic concern. During replacement of levers, mechanic drove lever onto shaft dislodging tripper fingers. Problems revealed with two other MOVs.

November 1993 - Nuclear station operator at Quad Cities Unit 1, while in cold shutdown for a maintenance outage, reopened reactor recirculation pump discharge valve without procedure guidance.

ROOT CAUSE AND TRENDING OF MOV PROBLEMS

June 1991 - Fitzpatrick remained shutdown while root cause of failure of MOVs in both trains of LPCI system evaluated. Licensee later identified multiple MOV deficiencies.

January 1992 - Wolf Creek remained shutdown for six weeks after refueling while MOV problems evaluated.

May 1992 - Four EFW MOVs at Crystal River failed dynamic tests although one of these MOVs had failed a dynamic test in October 1991.

February 1993 - At LaSalle Unit 1, RCIC steam line MOV failed on February 10 and, after motor replacement, again on February 26.

Spring 1994 - Region III reported that Byron AFW MOV failed to operate in Fall 1993 although CECo identified operability problems with these AFW MOVs in September 1990.

PROPOSED SUPPLEMENT 7 TO GL 89-10

WESTINGHOUSE OWNERS GROUP REQUESTED THAT NRC STAFF ELIMINATE RECOMMENDATION IN GL 89-10 THAT INADVERTENT VALVE MISPOSITIONING BE CONSIDERED IN GL 89-10 PROGRAMS AT PWR PLANTS.

NRR CONTRACTED BNL TO PERFORM STUDY SIMILAR TO THAT PERFORMED FOR BWR PLANTS AND DISCUSSED IN SUPPLEMENT 4.

NRC STAFF IS PREPARING PROPOSED SUPPLEMENT 7 TO ADDRESS THE NEED TO CONSIDER INADVERTENT MOV OPERATION IN GL 89-10 PROGRAMS AT PWR PLANTS.

NRR STAFF MET WITH CRGR ON MAY 10 AND IS RESOLVING CRGR COMMENTS BEFORE ISSUANCE FOR PUBLIC COMMENT.

PROPOSED GENERIC LETTER ON PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES

AEOD ISSUED NUREG-1275, VOLUME 9, "PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES," IN EARLY 1993.

AT PUBLIC WORKSHOPS IN FEBRUARY 1993 AND 1994, NRC STAFF DISCUSSED SAFETY SIGNIFICANCE OF PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES.

GENERAL GUIDANCE FOR REVIEWING LICENSEE ACTION ON PRESSURE LOCKING AND THERMAL BINDING IN REVISION 1 TO TI 2515/109 AND A MEMORANDUM (APRIL 30, 1993) TO THE REGION OFFICES. INSPECTORS REVIEWING LICENSEE ACTION ON THIS ISSUE ARE FINDING LITTLE PROGRESS IN THIS AREA.

ON FEBRUARY 8, 1993, NRC STAFF REQUESTED NUMARC (NOW NEI) TO PROVIDE SPECIFIC GUIDANCE ON ACCEPTABLE APPROACHES TO ANALYZE AND REMEDY PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES. AT A PUBLIC MEETING ON OCTOBER 4, 1993, NUMARC STATED THAT, BASED ON A SURVEY, IT HAD NOT FOUND PRESSURE LOCKING EVENTS BEYOND THOSE IDENTIFIED BY AEOD AND DID NOT PLAN TO TAKE ANY ACTION TO ADDRESS THIS ISSUE.

PRESSURE LOCKING AND THERMAL BINDING MIGHT NOT OCCUR UNTIL PLANT CONDITIONS EXIST THAT REQUIRE OPERATION OF THE VALVE. THEREFORE, ABSENCE OF PREVIOUS EVENT NOT SUFFICIENT.

EXAMPLES OF METHODS TO PREVENT PRESSURE LOCKING AND THERMAL BINDING DISCUSSED IN NUREG-1275, VOLUME 9.

THRUST REQUIRED TO OVERCOME PRESSURE LOCKING OR THERMAL BINDING IS DIFFICULT TO PREDICT. IF POWER-OPERATED VALVE IS CONSIDERED CAPABLE OF MEETING THRUST REQUIREMENT, METHODOLOGY USED TO PREDICT THE THRUST REQUIREMENT NEEDS TO BE BASED ON TESTING.

IF POWER-OPERATED VALVE IS SUSCEPTIBLE TO PRESSURE LOCKING OR THERMAL BINDING, AND POWER OPERATOR CANNOT OVERCOME THRUST REQUIREMENT, THE VALVE MAY BE IN A DEGRADED OR NONCONFORMING CONDITION.

GENERIC LETTER 91-18 PROVIDES GUIDANCE TO LICENSEES ON THE DISPOSITION OF POTENTIALLY DEGRADED OR NONCONFORMING CONDITIONS.

STAFF IS CONSIDERING NEED FOR LICENSEES TO

A. EVALUATE OPERATIONAL CONFIGURATION FOR EACH SAFETY-RELATED POWER-OPERATED GATE VALVE AND DOCUMENT BASES FOR DETERMINATION OF SUSCEPTIBILITY

B. DETERMINE APPROPRIATE CORRECTIVE ACTION FOR IDENTIFIED VALVES.

GL 89-10 PROGRAM STATUS

GL 89-10 COMPLETION

CALLAWAY HAS COMPLETED GL 89-10 DESIGN-BASIS VERIFICATION AND ESTABLISHED A PERIODIC VERIFICATION PROGRAM.

FORT CALHOUN AND COMANCHE PEAK READY FOR GL 89-10 CLOSE-OUT.

SEVERAL OTHER LICENSEES ARE APPROACHING COMPLETION OF GL 89-10 DESIGN-BASIS VERIFICATION.

GL 89-10 SCHEDULE EXTENSIONS

SEVERAL LICENSEES HAVE REQUESTED, OR ARE PLANNING TO REQUEST, EXTENSIONS OF GL 89-10 TEST SCHEDULES AS DISCUSSED IN SUPPLEMENT 6 TO GL 89-10.

NEA/IAEA SPECIALIST MEETING ON MOVs
APRIL 25-28, 1994
PARIS, FRANCE

OVER 100 PARTICIPANTS

COUNTRIES INCLUDED BELGIUM, CANADA, CZECH REPUBLIC, FINLAND, FRANCE, GERMANY, HUNGARY, INDIA, JAPAN, MEXICO, NETHERLANDS, RUSSIA FEDERATION, SLOVAKIA, SLOVENIA, SPAIN, SWEDEN, SWITZERLAND, UKRAINE, UNITED KINGDOM, AND USA.

SESSIONS:

REGULATORY ACTIVITY,

OPERATING EXPERIENCE,

MOV IMPROVEMENT PROGRAMS,

RESEARCH AND DEVELOPMENT, AND

TESTING AND MAINTENANCE.

HIGHLIGHTS:

* MOV PROBLEMS CONTINUE TO OCCUR AT NUCLEAR POWER PLANTS AROUND THE WORLD.

* REGULATORY AUTHORITIES IN VARIOUS COUNTRIES (SUCH AS BELGIUM, FRANCE, GERMANY, SLOVAKIA, SPAIN, SWEDEN, UNITED KINGDOM, AND USA) HAVE REQUESTED NUCLEAR POWER PLANT UTILITIES TO VERIFY CAPABILITY OF MOVs TO PERFORM THEIR SAFETY FUNCTION UNDER DESIGN-BASIS CONDITIONS.

NEA/IAEA SPECIALIST MEETING ON MOVs
(CONTINUED)

HIGHLIGHTS (CONTINUED):

* FRENCH ACTIVITIES ON MOVs SIMILAR TO GL 89-10 ALTHOUGH NRC STAFF HAD NOT BEEN AWARE OF THESE ACTIVITIES.

* FRANCE AND GERMANY ARE AHEAD OF USA IN ADDRESSING PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES.

* DISCUSSION OF RESEARCH ACTIVITIES FOCUSED ON USA, BUT FRANCE, GERMANY AND UNITED KINGDOM ALSO HAVE CONDUCTED TESTING AND ANALYSIS PROGRAMS.

* USE OF MOV DIAGNOSTIC EQUIPMENT INCREASING.

* NEED FOR IMPROVED PREVENTIVE MAINTENANCE AND PERIODIC TESTING OF MOVs RECOGNIZED, BUT ADDITIONAL WORK NECESSARY TO REACH CONSENSUS ON BEST METHODS.

* EFFORTS ARE BEING MADE TO FOCUS ON THE MOST SAFETY SIGNIFICANT MOVs, BUT ONLY USA HAS ONGOING REGULATORY AND INDUSTRY PROGRAMS FOR EVALUATING RISK-BASED METHODS.

CONCLUSION:

* SPECIFIC MOV EQUIPMENT IS DIFFERENT.

* MOV PROBLEMS AND APPROACHES TO RESOLVING THOSE PROBLEMS ARE SIMILAR IN VARIOUS COUNTRIES.

EPRI MOV PERFORMANCE PREDICTION PROGRAM

NUCLEAR POWER PLANT LICENSEES INITIATED THE EPRI MOV PERFORMANCE PREDICTION PROGRAM IN AN EFFORT TO ALLOW STATIC TESTS OF MOVs TO BE USED TO PREDICT THE PERFORMANCE OF MOVs UNDER DYNAMIC CONDITIONS.

EPRI HAS OBTAINED A SIGNIFICANT AMOUNT OF DATA FROM ITS TESTS OF MOVs IN FLOW LOOPS AND TESTS OF MOVs AT NUCLEAR POWER PLANTS.

EPRI IS EVALUATING THE MOV TEST DATA TO DEVELOP ITS MOV PERFORMANCE PREDICTION METHODOLOGY.

THE EPRI TEST DATA REVEAL THAT VALVE VENDORS UNDERPREDICTED THE THRUST REQUIRED TO OPERATE
(1) MANY TYPES AND SIZES OF GATE VALVES, AND
(2) SOME GLOBE VALVES.

EPRI HAS NOT FOUND UNDERPREDICTION OF BUTTERFLY VALVE TORQUE REQUIREMENTS. HOWEVER, SOME LICENSEES HAVE IDENTIFIED TORQUE UNDERPREDICTION FOR THEIR BUTTERFLY VALVES.

NRC STAFF ISSUED INFORMATION NOTICE 93-88, "STATUS OF MOV PERFORMANCE PREDICTION PROGRAM BY THE ELECTRIC POWER RESEARCH INSTITUTE," TO ALERT LICENSEES TO PRELIMINARY RESULTS OF THE MOV TESTS CONDUCTED BY EPRI.

EPRI MOV PERFORMANCE PREDICTION PROGRAM
(CONTINUED)

MANY LICENSEES WILL BE RELYING ON THE EPRI MOV TEST DATA THROUGH EITHER THE EPRI METHODOLOGY OR AS PROTOTYPE DATA TO DEMONSTRATE THAT MOVs ARE CAPABLE OF PERFORMING THEIR DESIGN-BASIS FUNCTION.

SOME LICENSEES HAVE IDENTIFIED IMMEDIATE PROBLEMS WITH PARTICULAR MOVs BASED ON THE EPRI TEST DATA.

EPRI HAS BEGUN SUBMITTING INDIVIDUAL TEST REPORTS IN SUPPORT OF THE TOPICAL REPORT ON ITS MOV PERFORMANCE PREDICTION METHODOLOGY. THE STAFF HAS INITIATED REVIEW OF THOSE REPORTS.

STAFF HAS PERIODICALLY MET WITH NUMARC AND EPRI TO DISCUSS THE EPRI MOV PROGRAM WITH THE NEXT MEETING SCHEDULED FOR JUNE 28-29, 1994, AT OWFN.

CURRENT NRC STAFF ACTIVITIES ON MOVs

INSPECTIONS USING PART 2 OF TI 2515/109 (REV. 1) TO EVALUATE GL 89-10 PROGRAM IMPLEMENTATION BEING CONDUCTED.

STAFF REVIEWING CLOSE-OUT OF GL 89-10 AS LICENSEES COMPLETE PROGRAMS.

STAFF REVIEWING GL 89-10 SCHEDULE EXTENSION JUSTIFICATION FOR CERTAIN LICENSEES.

STAFF HAS REVIEWED A STUDY OF MOV MISPOSITIONING IN PWR PLANTS AND IS PREPARING SUPPLEMENT 7 TO ADDRESS THE STAFF'S CONCLUSIONS.

STAFF IS PREPARING PROPOSED GENERIC LETTER 94-XX ON PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES.

NRC STAFF REVIEWING TOPICAL REPORT ON EPRI MOV PERFORMANCE PREDICTION PROGRAM.

SPONSORING WITH ASME A SYMPOSIUM ON VALVE AND PUMP TESTING ON JULY 18-21, 1994, IN WASHINGTON, DC.

CHECK VALVES

NRC ACTION PLAN FOR CHECK VALVES
NUREG-1352
JUNE 1990

MAJOR ACTIONS INCLUDE:

IDENTIFICATION OF PROBLEMS AND PERFORMANCE WEAKNESSES.

ASSESS ADEQUACY OF REGULATORY REQUIREMENTS.

SUPPORT DEVELOPMENT OF CODES AND STANDARDS.

DEVELOP INSPECTION GUIDANCE.

CONDUCT RESEARCH STUDIES.

EVALUATE EFFECTIVENESS OF LICENSEE ACTIVITIES REGARDING TESTING AND PERFORMANCE OF SAFETY-RELATED CHECK VALVES.

EVALUATE INDUSTRY IMPROVEMENT EFFORTS.

DETERMINE NEED FOR NEW REGULATORY GUIDANCE.

TEMPORARY INSTRUCTION 2515/110
ON CHECK VALVE INSPECTIONS

ISSUED TO EVALUATE EFFECTIVENESS OF LICENSEE CHECK VALVE PROGRAMS AND ACTIVITIES.

INSPECTIONS FOUND BACKFLOW TESTING OMISSIONS AND MINIMAL FAILURE TRENDING.

LICENSEES WERE IN VARIOUS STAGES OF IMPLEMENTING RELIABILITY OR PREVENTIVE MAINTENANCE PROGRAMS AND THE PROGRAMS LACKED CONSISTENCY.

MANY LICENSEES HAD RECENTLY INITIATED PROGRAMS AND FOCUSED ACTIVITIES.

STAFF IDENTIFIED NEED FOR A HISTORICAL CHECK VALVE FAILURE ASSESSMENT. STAFF REQUESTED OAK RIDGE NATIONAL LABORATORY TO RESEARCH AND CHARACTERIZE FAILURE AND DEGRADATION FOR 1984-1990. ORNL ISSUED NUREG/CR-5944 IN 1993. ORNL IS PREPARING FAILURE AND DEGRADATION UPDATES FOR 1991 AND 1992.

CURRENT NRC STAFF ACTIVITIES ON CHECK VALVES

CONTINUE INSPECTIONS OF CHECK VALVE PROGRAMS AND ACTIVITIES AT NUCLEAR PLANTS USING TI 2515/110.

CONTINUE STAFF ATTENTION TO CHECK VALVES TO MAINTAIN THE CURRENT LEVEL OF FOCUS TO ACHIEVE THE DESIRED IMPROVEMENTS IN CHECK VALVE PERFORMANCE.

MONITOR INDUSTRY'S SYSTEMATIC EVALUATION AND ACTIONS WITH REGARD TO THE HISTORIC AND ANNUAL ASSESSMENTS OF REPORTED FAILURE AND DEGRADATION DATA.

CONTINUE TO MONITOR THE PREPARATION AND ISSUANCE OF INDUSTRY CHECK VALVE MAINTENANCE MANUAL AND ASSOCIATED NUCLEAR INDUSTRY CHECK VALVE GROUP (NIC) PROGRAMMATIC GUIDANCE.

EVALUATE THE FAILURE AND DEGRADATION UPDATE REPORTS, LICENSEE EVENT REPORTS, AND INDUSTRY ACTIVITIES TO ASSESS PERFORMANCE IMPROVEMENT TRENDS AND NEED FOR NEW GENERIC REQUIREMENTS OR GUIDANCE.

CURRENT NRC STAFF ACTIVITIES ON CHECK VALVES
(CONTINUED)

CONTINUE TO ATTEND NIC AND ASSOCIATED EPRI MEETINGS TO PRESENT NRC CONCERNS AND ENCOURAGE ACTIVITIES.

CONTINUE PARTICIPATION IN ASME-OM COMMITTEE WORKING GROUP ON CHECK VALVES TO IMPROVE TESTING REQUIREMENTS.

CONTINUE TO MONITOR AND ENCOURAGE PRO-ACTIVE EFFORTS OF NIC, EPRI, AND OM-22 IN CHECK VALVE ISSUES INCLUDING EVALUATION OF NONINTRUSIVE TEST METHODS, UPDATING APPLICATION GUIDES, CONDUCTING WORKSHOPS ON MAINTENANCE AND DIAGNOSTICS, DEVELOPING A MAINTENANCE MANUAL, IMPROVING CODE TESTING REQUIREMENTS, AND REVIEWING ISSUES HIGHLIGHTED IN ORNL FAILURE REPORT.

T-13, 13 14

AEOD STAFF PRESENTATION TO THE ACRS

SUBJECT:	POTTER & BRUMFIELD MDR ROTARY RELAYS
DATE:	JUNE 10, 1994
PRESENTER:	ROBERT A. SPENCE, P.E.
PRESENTER'S TITLE/BRANCH/DIV:	REACTOR SYSTEMS ENG. ROAB/DSP
PRESENTER'S NRC TEL. NO.:	(301) 415-6346

POTTER & BRUMFIELD

"MDR" RELAYS

- 3000 MDR RELAYS IN 35 PLANTS
- 124 DEPENDENT FAILURES (1984-1992)
- 1/3 INVOLVED MULTIPLE FAILURES
- FOUND DURING TESTING OR EVENTS

SAFETY SIGNIFICANCE

- REACTOR PROTECTION SYSTEM

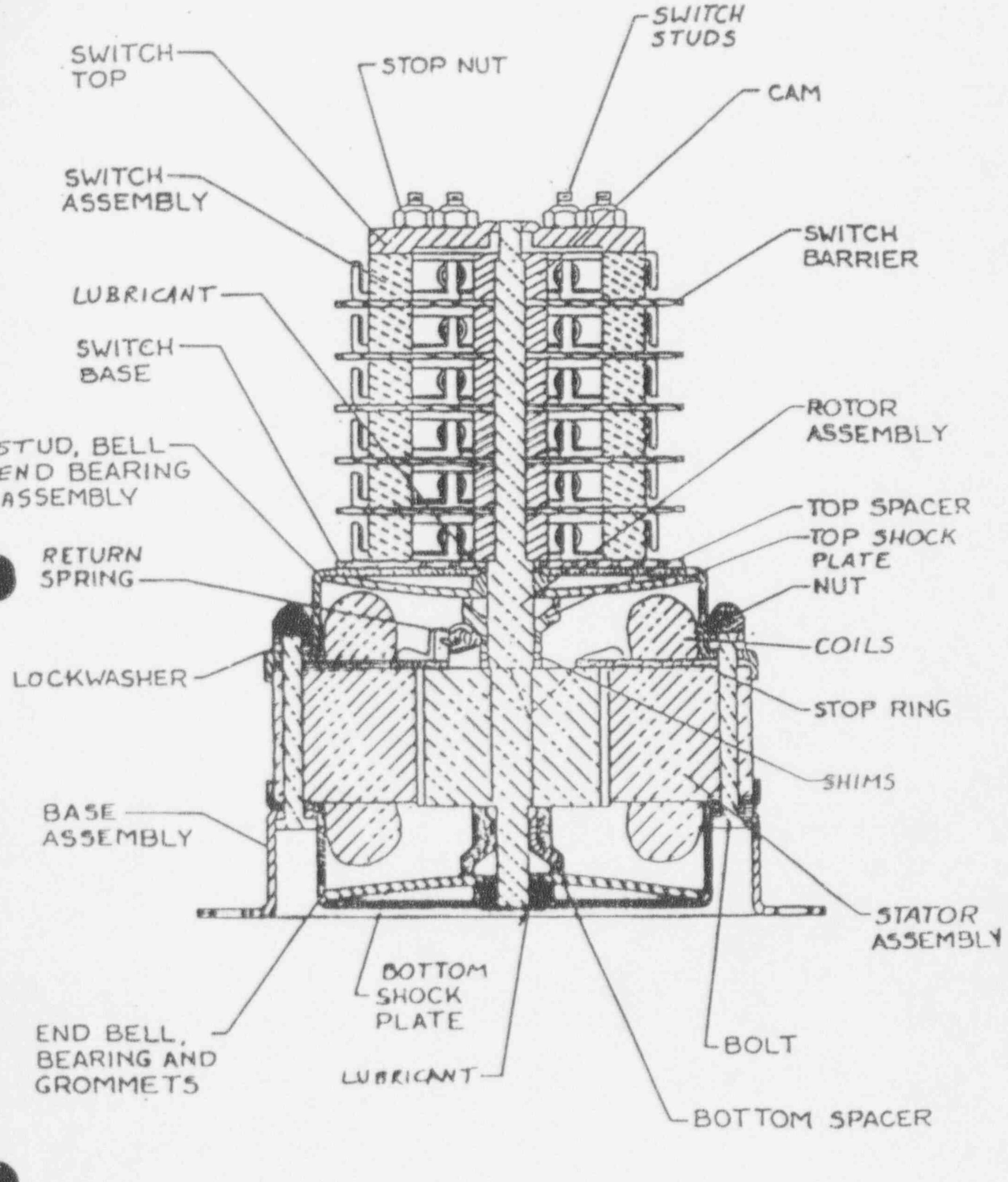
- EMERGENCY CORE COOLING SYSTEMS

- ENGINEERING SAFETY FEATURE SYSTEMS

- SIMULTANEOUS MULTIPLE FAILURES

MDR NON-LATCHING RELAY

(MEDIUM)



MDR RELAY FAILURE MECHANISMS

- ## ROTOR SHAFT BINDING
  - COIL VARNISH OUTGASSING AND CHLORINE FROM GROMMETS, PAINT AND WIRING
  - OVERSIZED COIL AND SHIMMING
  - UNCURED TRAMP EPOXY
  - SHADING COIL DETACHMENT

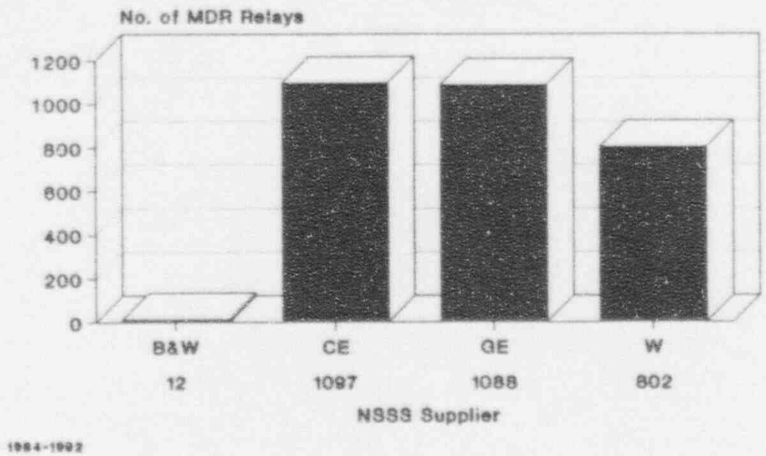
- ## CONTACT CONTINUITY
  - HIGH RESISTANCE - SILVER CORROSION/LOW LOADS
  - INTERMITTENT CONTINUITY - CONTACT EROSION FROM INDUCTIVE LOADS NOT IN DESIGN
  - CONTACT FAILURE - PARALLELING SETS OF CONTACTS

- ## RADIATION AGING

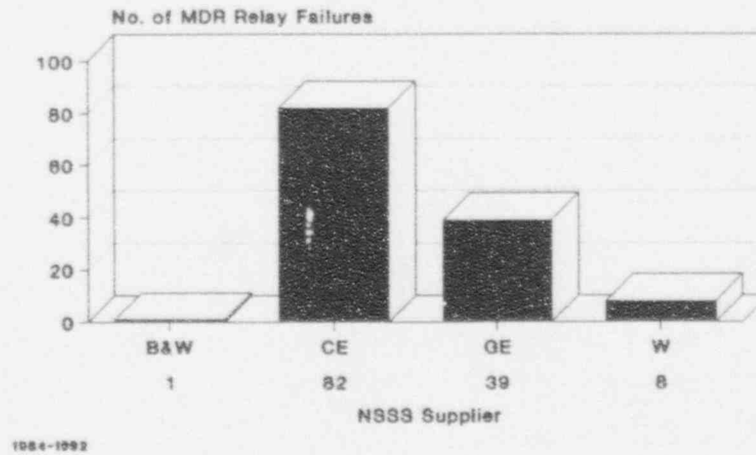
PRA CONSIDERATIONS

- 8-10 SIMULTANEOUS MULTIPLE FAILURE EVENTS
  - 4 EXPECTED
  - COMMON-MODE FAILURES
  - SIMULTANEOUS MULTIPLE FAILURES
  - ECCS, EDG, RPS AND SUPPORT SYSTEMS ACTUATION LOGIC
- PRAs DO NOT MODEL RELAYS - PLANT SPECIFIC
- RIVER BEND RPS FAILURE PROBABILITY INCREASED BY 25 TIMES FROM 1.3 X E-5 TO 3.3 X E-4 FAILURES/DEMAND

P&B MDR Relay Usage vs Reactor Supplier

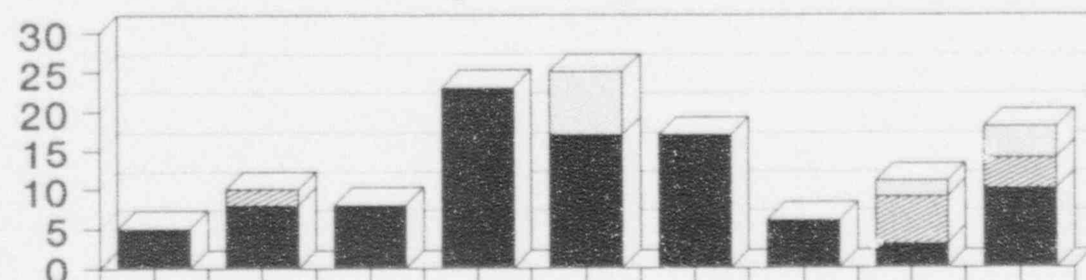


P&B MDR Relay Failures vs Reactor Supplier



P&B MDR Relay Failures
vs
Year

No. of MDR Relay Failures



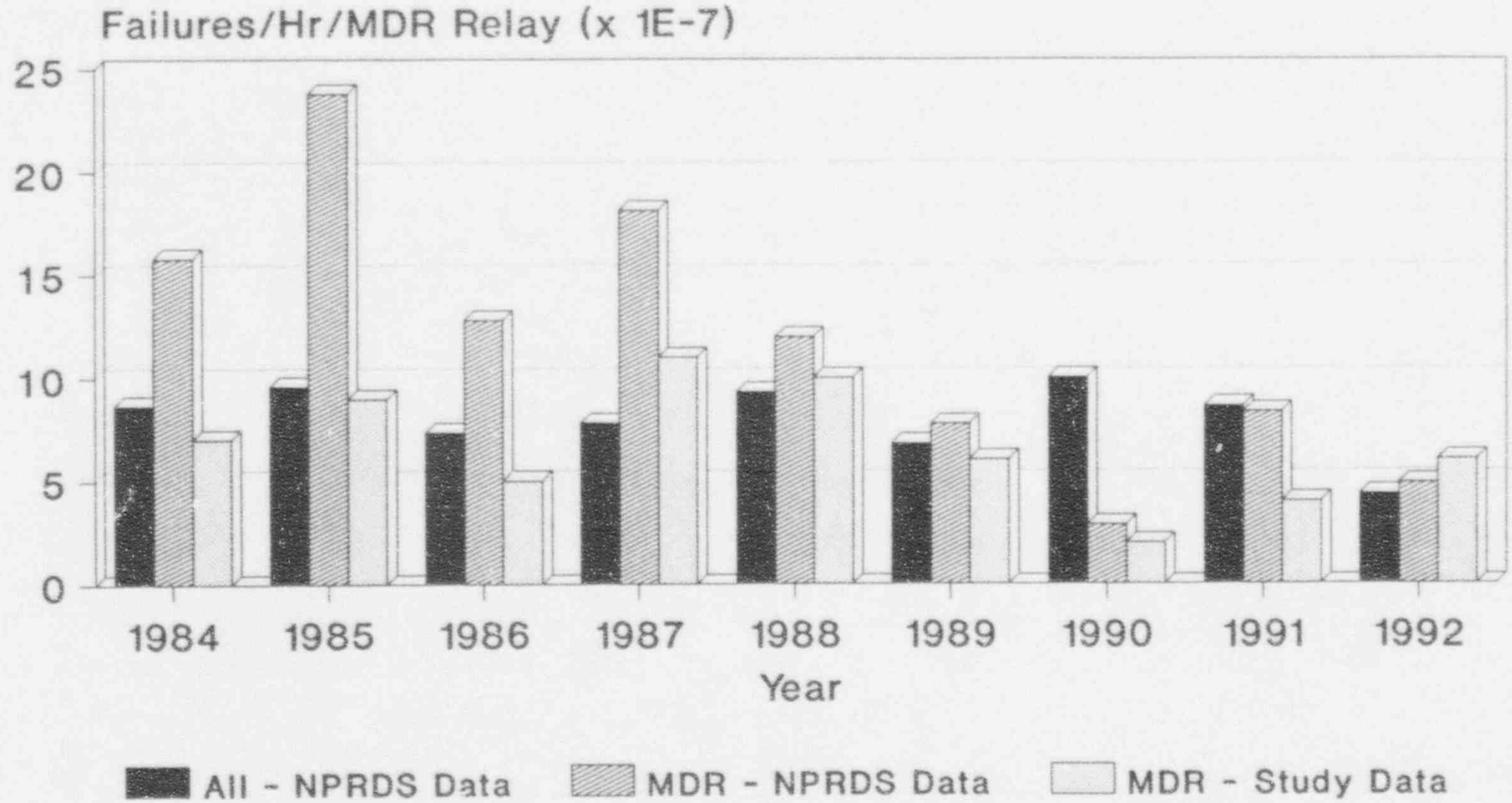
	1984	1985	1986	1987	1988	1989	1990	1991	1992
Multiple Failures					8			2	4
Common Mode Failures		2						6	4
Single Failures	5	8	8	23	17	17	6	3	10

Year

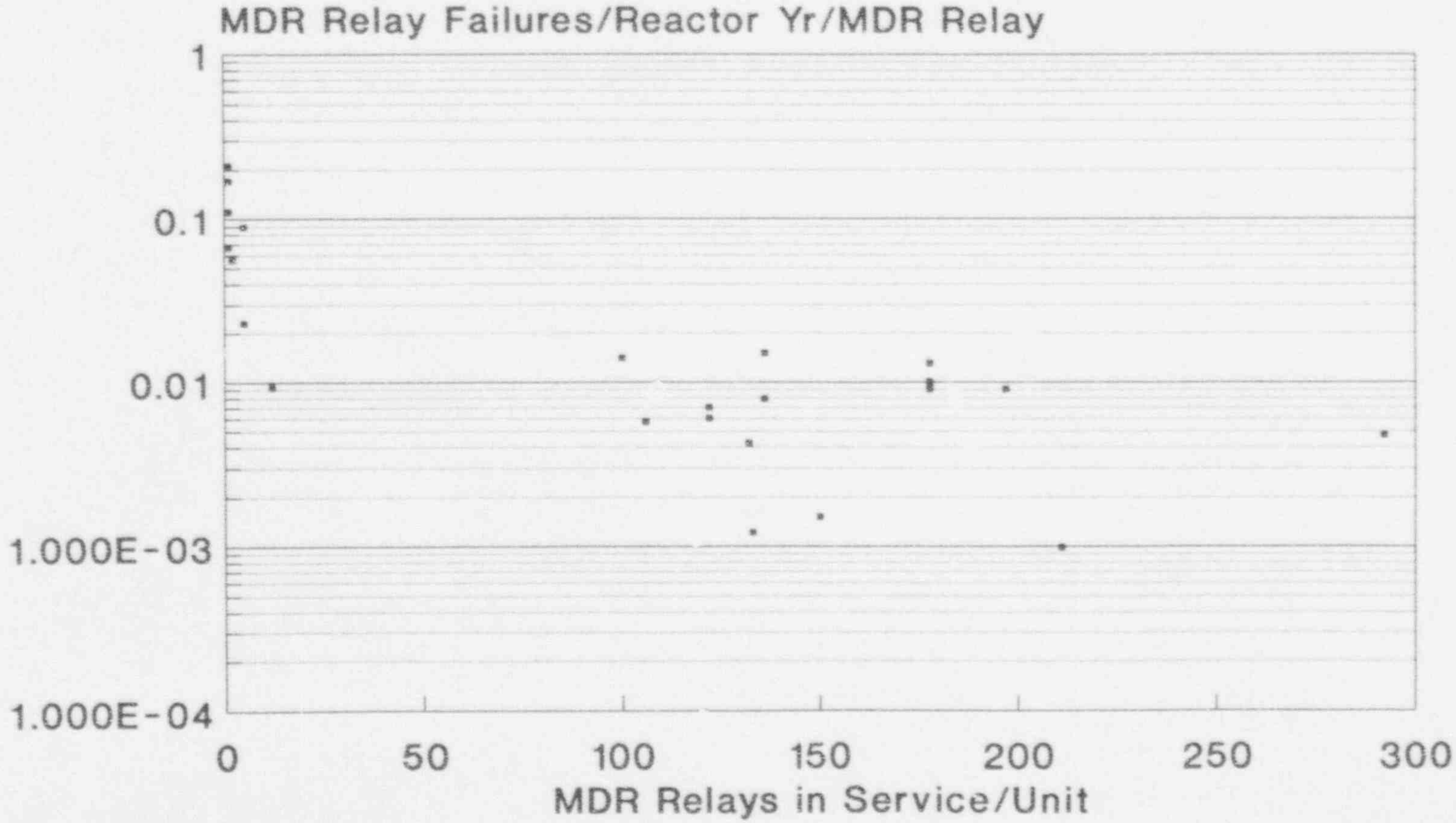
Single Failures
Common Mode Failures
Multiple Failures

1984-1992

P&B MDR Relay Failure Rates vs Year

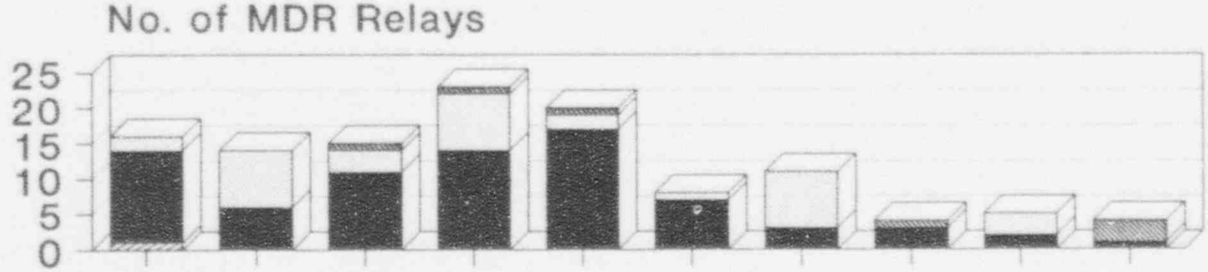


P&B MDR Relay Failure Rate by Unit
vs
No. in Service/Unit



1984-1992

P&B MDR Relay Failures
vs
Service Life at Failure by NSSS



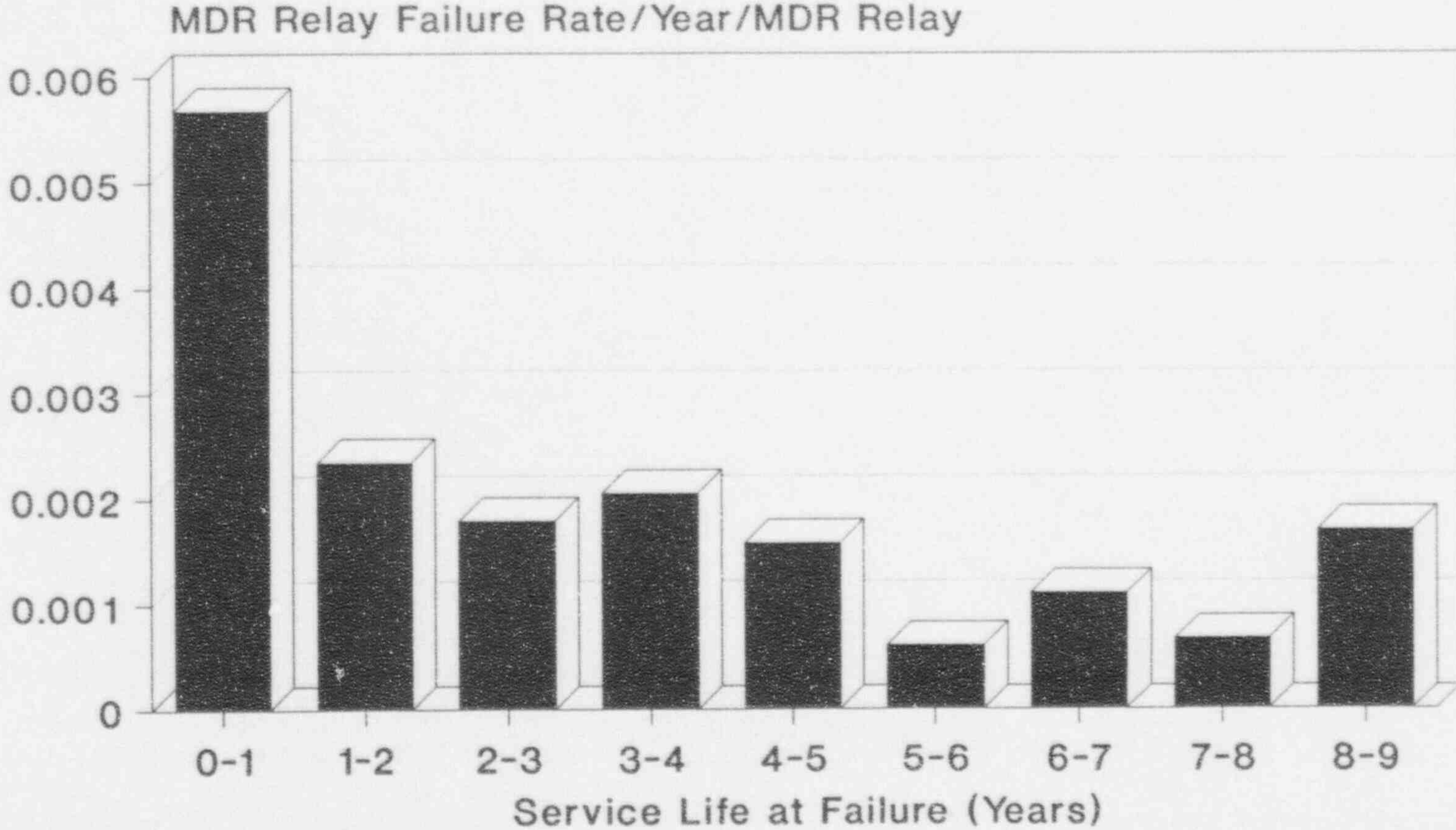
	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	›9
Westinghouse	0	0	1	1	1	0	0	1	0	3
General Electric	2	8	3	8	2	1	8	0	3	0
Combustion Engg	13	6	11	14	17	7	3	3	2	1
Babcox & Wilcox	1									

Service Life at Failure (years)

Babcox & Wilcox — Combustion Engg
General Electric — Westinghouse

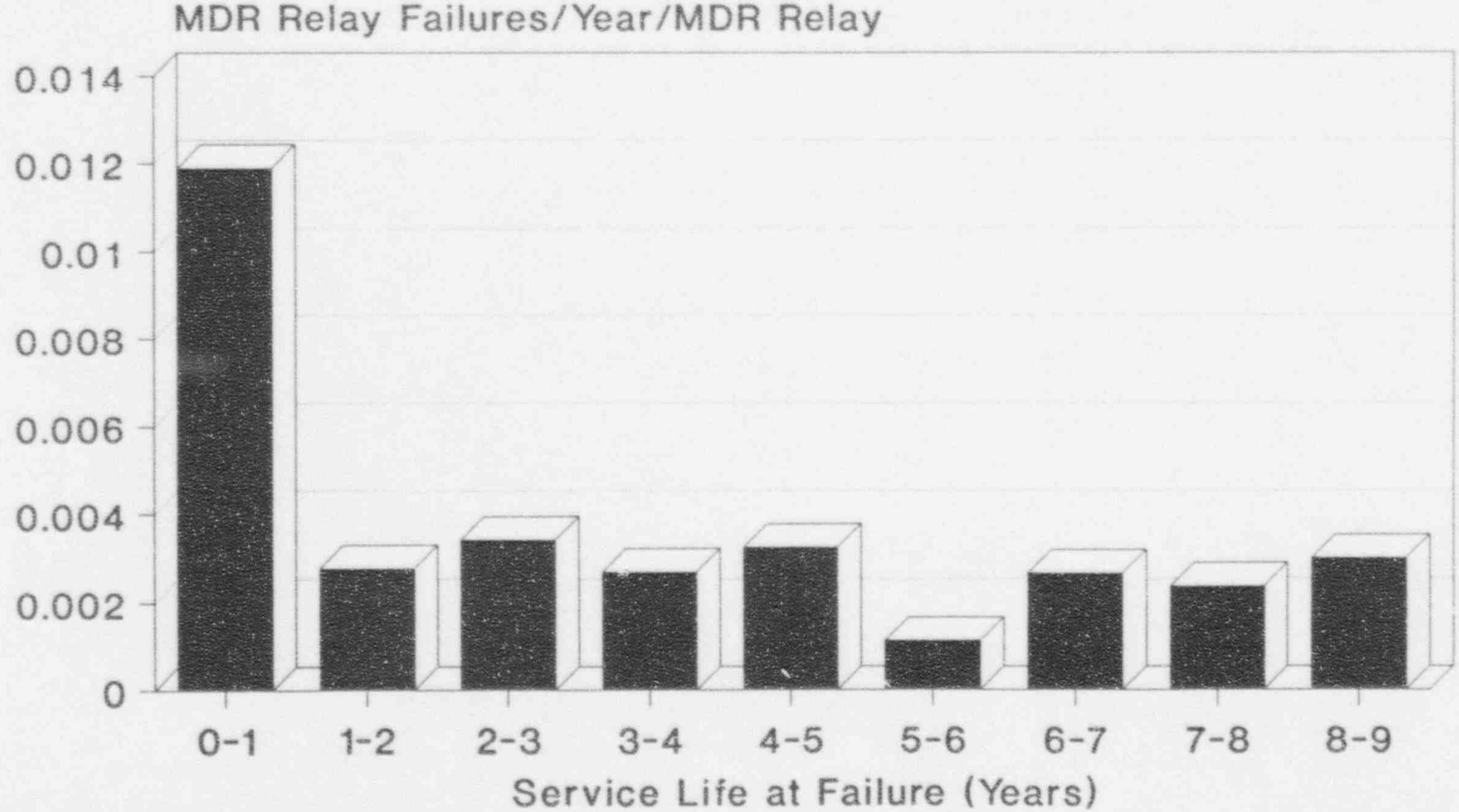
1984-1992

P&B MDR Relay Failure Rate vs Service Life



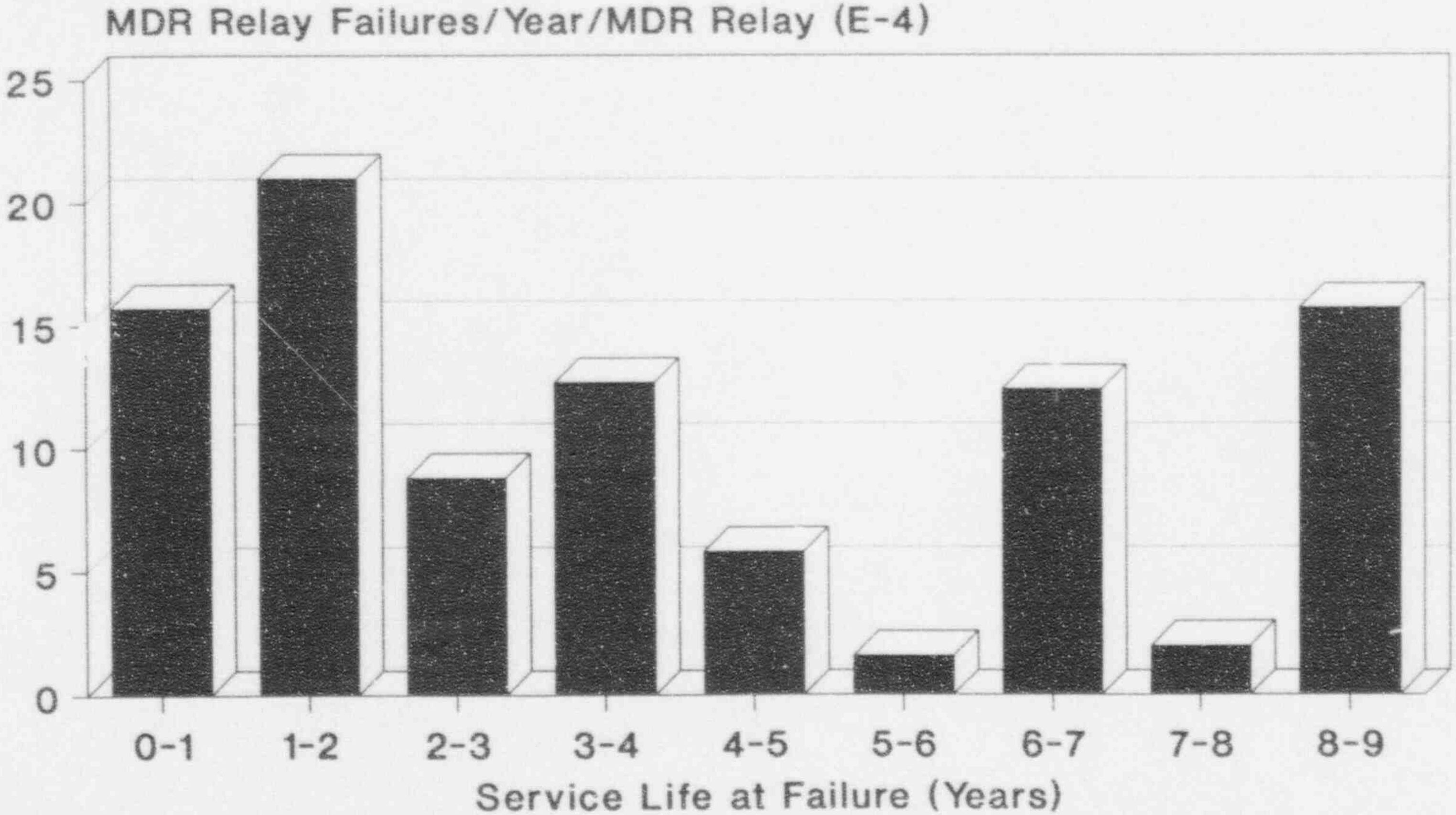
1984-1992

P&B MDR Relay Failure Rate vs Service Life at Failure for CE Plants



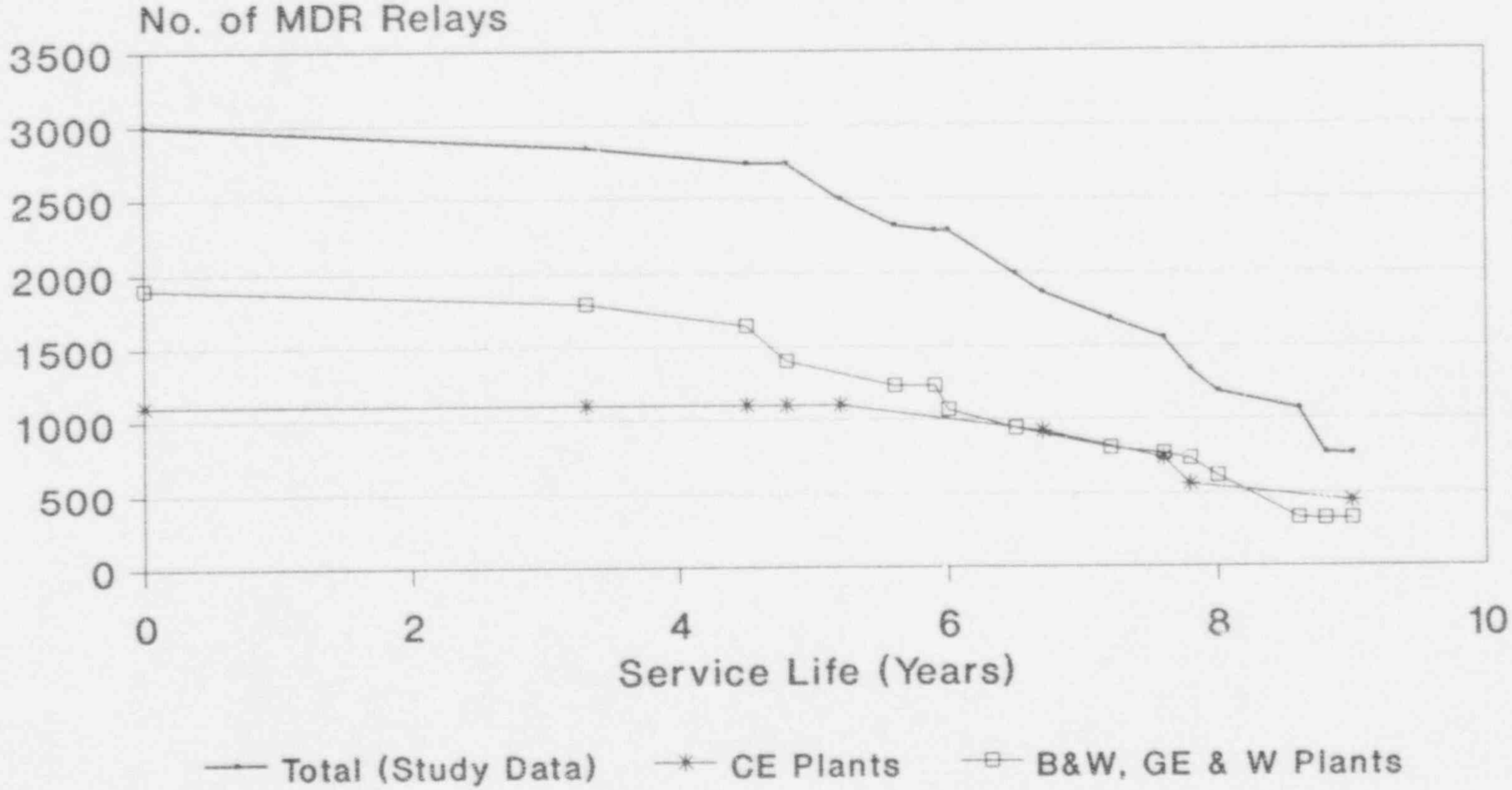
1984-1992

P&B MDR Relay Failure Rate vs Service Life at Failure for B&W, GE & W Plants



1984-1992

P&B MDR Relay Accumulated Service Life



12/31/1992

CONCLUSIONS

- AEOD SPECIAL STUDY S93-06
- SUGGESTED SUPPLEMENT TO IN 92-04
- NUREG

T-6.

ACRS PRESENTATION

ON

OPERATING REACTOR EVENTS

JUNE 10, 1994

Introduction	Alfred E. Chaffee, Chief Events Assessment Branch
Cooper and Other BWRs	Neal K. Hunemuller Senior Reactor Systems Engineer Events Assessment Branch
Sequoyah, Unit 1	David E. LaBarge Senior Project Manager Project Directorate II-4
Coordinated by: Division of Operating Reactor Support Brian K. Grimes, Director	Senior NRR Technical Manager: Martin J. Virgilio, Acting Director Division of Systems Safety and Analysis

COOPER & OTHER BWRs

LOSS OF SHUTDOWN COOLING DUE TO PRESSURE TRANSIENTS

PRESENTATION BEFORE THE
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
BY

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JUNE 10, 1994

DISCUSSION

PROBLEM

PRESSURE TRANSIENTS IN THE SHUTDOWN COOLING (SDC) PIPING HAVE CAUSED SHORT DURATION LOSSES OF SDC.

CAUSE

CLEARING OR COLLAPSE OF AIR OR STEAM VOIDS CAUSE THE PRESSURE SWITCHES PROTECTING THIS LOW-PRESSURE PIPING TO SENSE A HIGH PRESSURE ISOLATION CONDITION.

DISCUSSION

- COOPER:
    - ON MARCH 17, 1994, THE PLANT LOST SDC FOR 13 MINUTES. TEMPERATURE INCREASED FROM 184°F TO 189°F. VESSEL LEVEL DECREASED 7".
    - SDC HAD BEEN INITIATED 2 1/2 HOURS EARLIER. THE HEAD VENTS HAD BEEN OPENED 44 MINUTES EARLIER WHEN TEMPERATURE HAD BEEN REDUCED BELOW 200°F.
    - THE COLLAPSE OF A VOID IN THE RHR OR REACTOR RECIRCULATION PIPING WAS IDENTIFIED AS THE MOST PROBABLE CAUSE.

- VERMONT YANKEE

  - ON DECEMBER 17, 1993, A SDC ISOLATION OCCURRED WHILE ATTEMPTING TO START AN RHR PUMP. WHEN THE INJECTION VALVE WAS THROTTLED OPEN VESSEL LEVEL DECREASED 3".

  - SDC WAS REESTABLISHED WITH THE SAME PUMP 13 MINUTES LATER.

  - THE APPARENT CAUSE OF THE EVENT WAS THE PRESENCE OF AIR OR STEAM VOIDS IN THE SDC LOOP WHICH PRODUCED PRESSURE SURGES IN THE SYSTEM.

- PILGRIM

  - ON JULY 22, 1993, A SDC ISOLATION OCCURRED WHEN AN RHR PUMP WAS STARTED AND THE INJECTION VALVE WAS OPENED TO INITIATE SDC FLOW. SDC WAS SUCCESSFULLY REINITIATED TWO MINUTES LATER.

  - THE CAUSE WAS DETERMINED TO BE A MOMENTARY PRESSURE TRANSIENT THAT ACTUATED THE PROTECTIVE HIGH PRESSURE SWITCHES.

- FITZPATRICK

  - ON FEBRUARY 25, MARCH 11, AND MAY 19, 1993, SDC ISOLATIONS OCCURRED WHILE ATTEMPTING TO PLACE SDC IN SERVICE. ON ALL THREE OCCASIONS, SDC WAS SUCCESSFULLY ESTABLISHED ON THE SECOND ATTEMPT.

  - DURING THE SECOND ATTEMPT ON MAY 19, 1993, REACTOR WATER LEVEL DECREASED 17". THIS WAS ATTRIBUTED TO THE MOVEMENT OF WATER FROM THE DOWNCOMER REGION TO THE MOISTURE SEPARATORS UPON PUMP START.

- THE LICENSEE'S REVIEW CONCLUDED THAT THE ROOT CAUSE OF THE ISOLATION SIGNALS WAS TRAPPED AIR IN THE INSTRUMENT TUBING FOR ONE OF THE PROTECTIVE PRESSURE SWITCHES.

- THE IMMEDIATE CORRECTIVE ACTION WAS TO ENSURE THE SENSING LINE WAS PROPERLY VENTED AND BACK-FILLED PRIOR TO PLACING SDC IN SERVICE. LONG-TERM CORRECTIVE ACTION IS TO RE-ROUTE THE SENSING LINE.

PREVIOUS SIMILAR EVENTS

- ON APRIL 20, 1992, JULY, 29, 1991, AND MARCH 14, 1991, COOPER, GRAND GULF AND VERMONT YANKEE, RESPECTIVELY, EXPERIENCED SIMILAR EVENTS. DEFICIENCIES IN THE SDC WARMING PROCEDURES WERE IDENTIFIED FOR EACH EVENT.

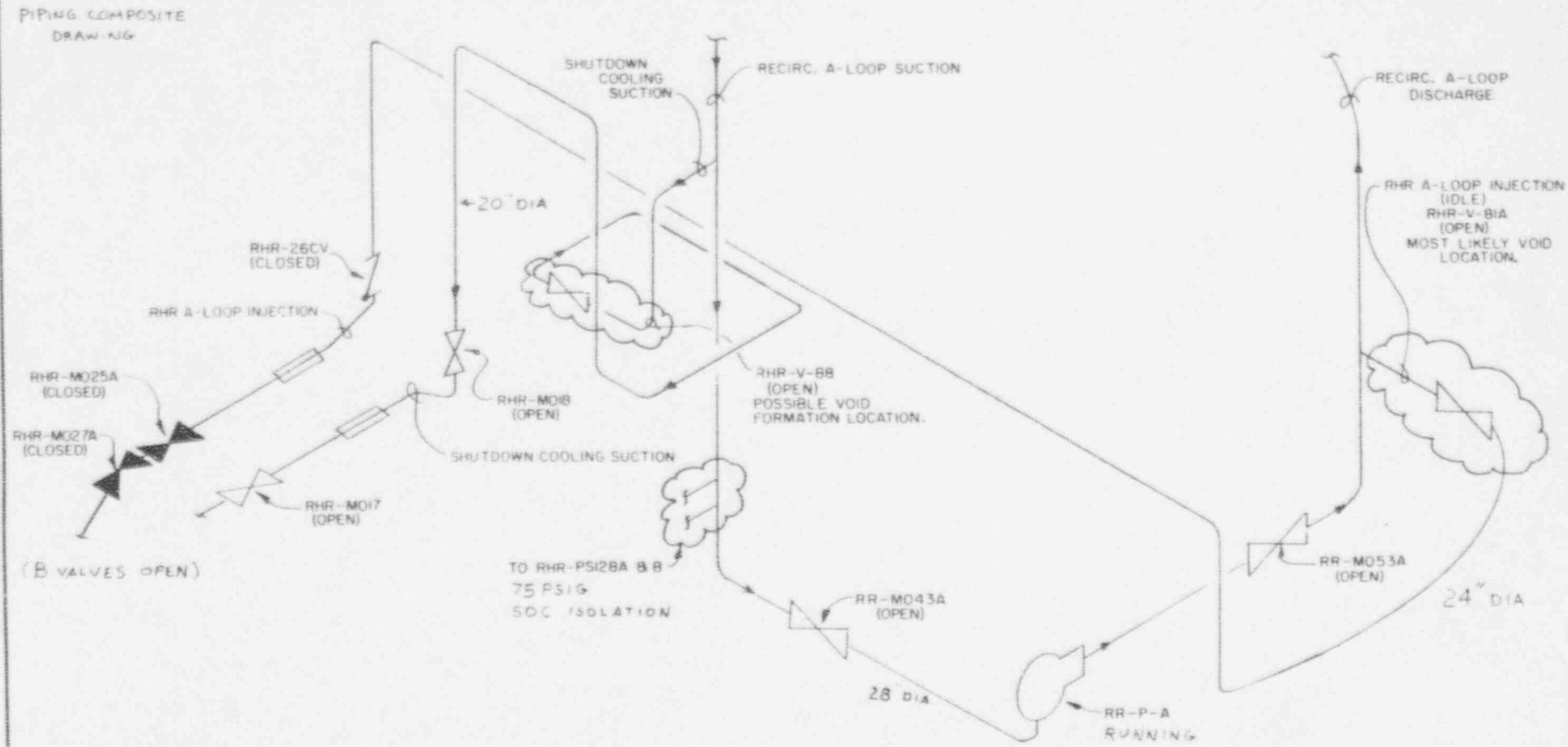
- IN JUNE 1976, G.E. ISSUED SIL NO. 175 BECAUSE SEVERAL BWRs HAD EXPERIENCED WATER HAMMER INVOLVING THE SDC MODE. NO DAMAGE WAS IDENTIFIED. THE SIL DISCUSSED THE CAUSES AND CORRECTIVE ACTIONS.
  - AIR OR STEAM VOIDS CAN ACCUMULATE IN THE SDC PIPING ANYWHERE A HUMP OR LOOP EXISTS THAT IS NOT ADEQUATELY VENTED.
  - THE SUBSEQUENT CLEARING OF THE AIR OR COLLAPSE OF THE STEAM VOID CAUSES A SDC ISOLATION DUE TO A SENSED HIGH PRESSURE AND MAY CAUSE A WATER HAMMER.

- G.E. RECOMMENDED THAT PLANTS REVIEW THE SDC MODE AND CONTROL FLOW AND PRESSURE SO AS TO MINIMIZE THE EFFECTS OF VOIDS.

<u>FOLLOWUP</u>

- PLANTS ARE COMMUNICATING WITH EACH OTHER AND WITH G.E. TO DETERMINE FURTHER PREVENTIVE OR MITIGATIVE ACTIONS.

- A SUPPLEMENT TO INFORMATION NOTICE 87-10, "WATER HAMMER DURING RESTART OF RHR PUMPS," IS IN DEVELOPMENT. THE NEED TO INCORPORATE INFORMATION ON SDC WATER HAMMERS IS BEING EVALUATED.



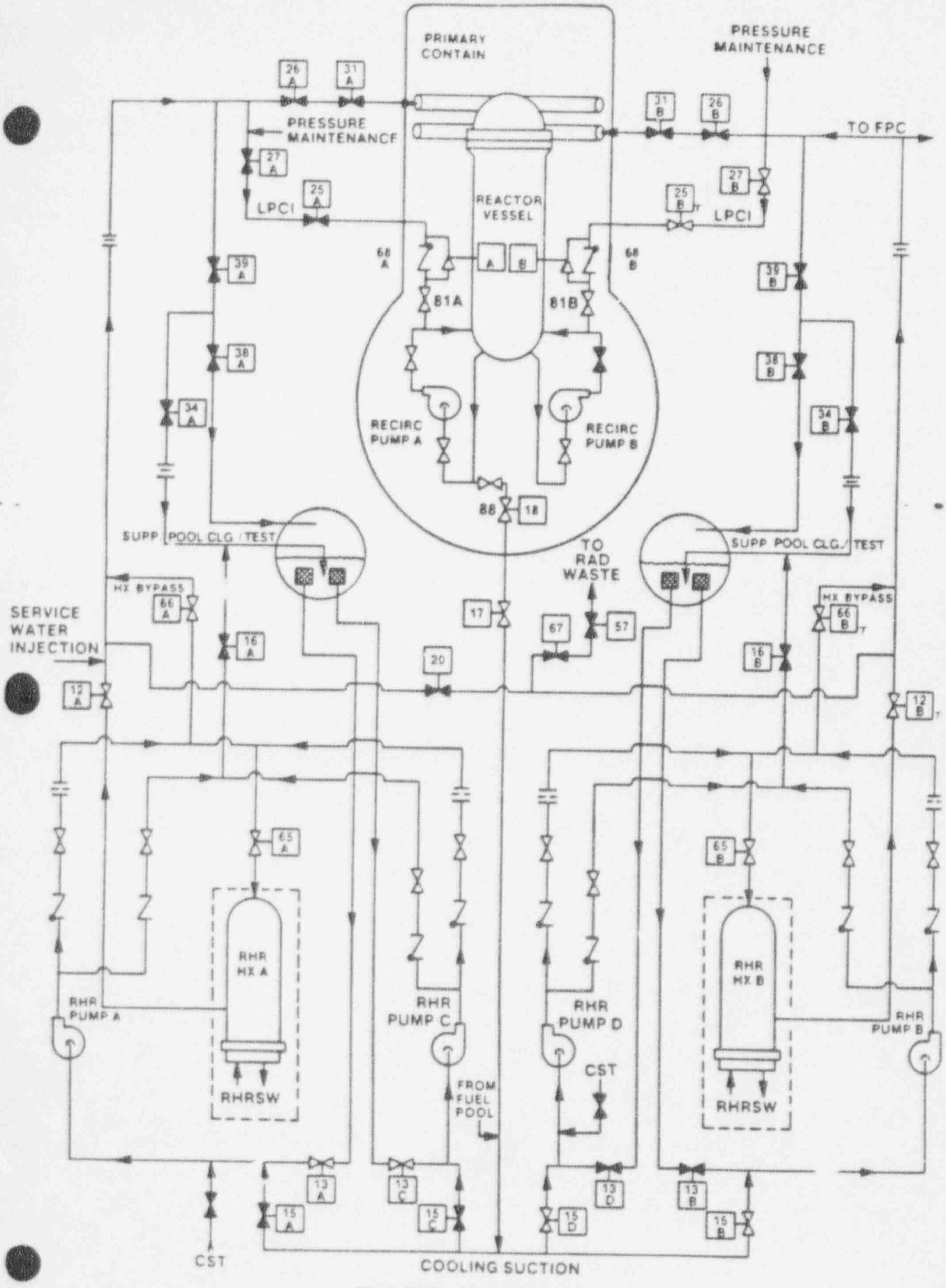
BRUNING 85110-02

NO | REVISIONS

CNS LOSS OF SHUTDOWN COOLING
RECIRC/RHR LINEUP

3-24-94

Nebraska Public Power District


PRIMARY CONTAIN
PRESSURE MAINTENANCE
26 A
31 A
31 B
26 B
PRESSURE MAINTENANCF
TO FPC
27 A
27 B
25 A
25 B
LPCI
LPCI
REACTOR VESSEL
68 A
68 B
A
B
39 A
39 B
81A
81B
38 A
38 B
34 A
34 B
RECIRC PUMP A
RECIRC PUMP B
88
18
SUPP. POOL CLG./TEST
SUPP. POOL CLG./TEST
TO RAD WASTE
HX BYPASS
HX BYPASS
66 A
66 B
SERVICE WATER INJECTION
17
67
57
16 A
16 B
20
12 A
12 B
65 A
65 B
RHR HX A
RHR HX B
RHR PUMP A
RHR PUMP C
RHR PUMP D
RHR PUMP B
RHRSW
RHRSW
FROM FUEL POOL
CST
13 A
13 C
13 D
13 B
15 A
15 C
15 D
15 B
CST
COOLING SUCTION

RHR SYSTEM

SEQUOYAH, UNIT 1

GAS BUBBLE EVENT

PRESENTATION BEFORE THE
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
BY

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PROJECT DIRECTORATE II-4
DIVISION OF REACTOR PROJECTS - I/II
(301) 504-1472

JUNE 10, 1994

- BRIEF DESCRIPTION OF EVENT

  WHEN CONTAINMENT PRESSURE WAS INCREASED TO PERFORM CONTAINMENT INTEGRATED LEAK RATE TEST ON 12/17/93, PRESSURIZER LEVEL INCREASED. INVESTIGATION DETERMINED THAT 30,000 GALLON BUBBLE EXISTED IN REACTOR VESSEL AND STEAM GENERATORS. THIS IS ALMOST ONE-THIRD OF THE NORMAL RCS WATER INVENTORY.

- PLANT DESCRIPTION
  - WESTINGHOUSE 4-LOOP PWR; MODE 5 ESTABLISHED.
  - VERY LITTLE DECAY HEAT (0.87 MWT) BECAUSE PLANT HAD BEEN SHUTDOWN FOR 9 MONTHS AND REFUELING OUTAGE COMPLETED.
- SEQUENCE OF EVENTS
  - 09/06/93 - SWEEPS AND VENTS PERFORMED AS PART OF POST-OUTAGE ACTIVITIES.
  - THEN LITTLE WORK ON UNIT 1. RHR SYSTEM RECIRCING REACTOR COOLANT SYSTEM, CHARGING SYSTEM RUNNING.

- 11/12/93 - LETDOWN HEAT EXCHANGER TEMPERATURE CONTROL VALVE PROBLEM CAUSED DECREASE IN VOLUME CONTROL TANK TEMPERATURE. VALVE PROBLEM CONTINUED UNTIL MID-JANUARY.

- 12/17/93 - CONTAINMENT INTEGRATED LEAK RATE TEST STARTED, PRESSURIZER LEVEL DECREASED. 5,000-8,000 GALLONS WATER ADDED, TEST CONTINUED.

- 12/20/93 - TEST COMPLETED. THEN, AS CONTAINMENT PRESSURE WAS DECREASED, PRESSURIZER LEVEL INCREASED. APPROXIMATELY 8,000 GALLONS DRAINED.

- 12/21/93 - TECHNICAL REVIEW STARTED. HEAD VENTED.

- 12/28/93 - COMPENSATORY ACTIONS INITIATED.

- 01/07/94 - TVA EVALUATION DETERMINED NITROGEN FROM THE VOLUME CONTROL TANK WAS THE SOURCE OF GAS.

- 01/13/94 TVA DETERMINED THAT LEVEL HAD DROPPED TO TOP OF HOT LEGS.

- 01/24/94, SWEEPS AND VENTS PERFORMED AND RCS PRESSURIZED.

- DESCRIPTION OF PROBLEM

  - NITROGEN FROM THE VOLUME CONTROL TANK CAME OUT OF SOLUTION IN THE REACTOR VESSEL AND STEAM GENERATORS.

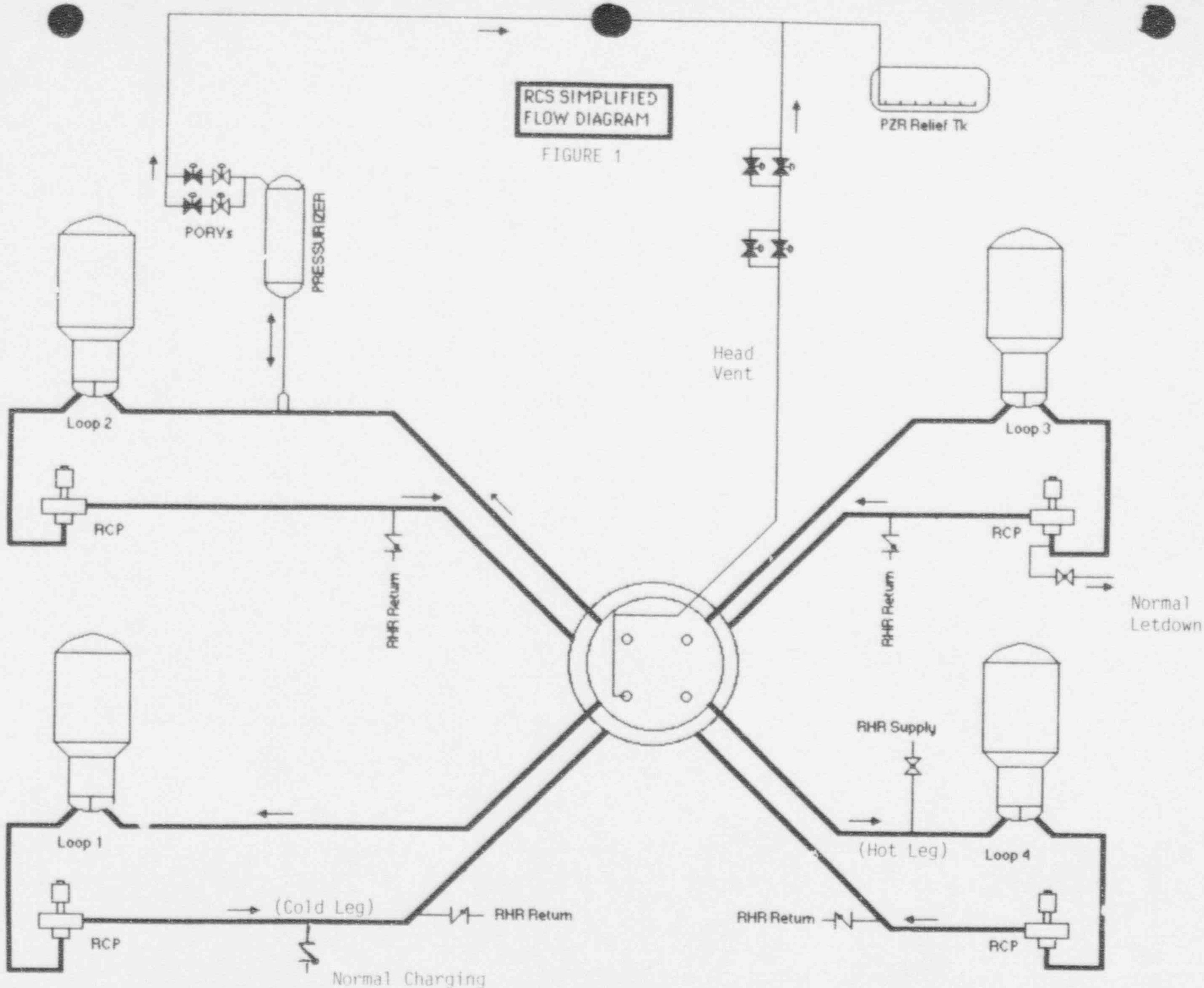
  - VOLUME CONTROL TANK AT 20 PSIG, 52-95°F.

  - RCS VENTED THROUGH PORVS, 120°F.

  - NITROGEN VENTED OUT THROUGH OPEN PORV ONCE LEVEL REACHED TOP OF HOT LEGS.

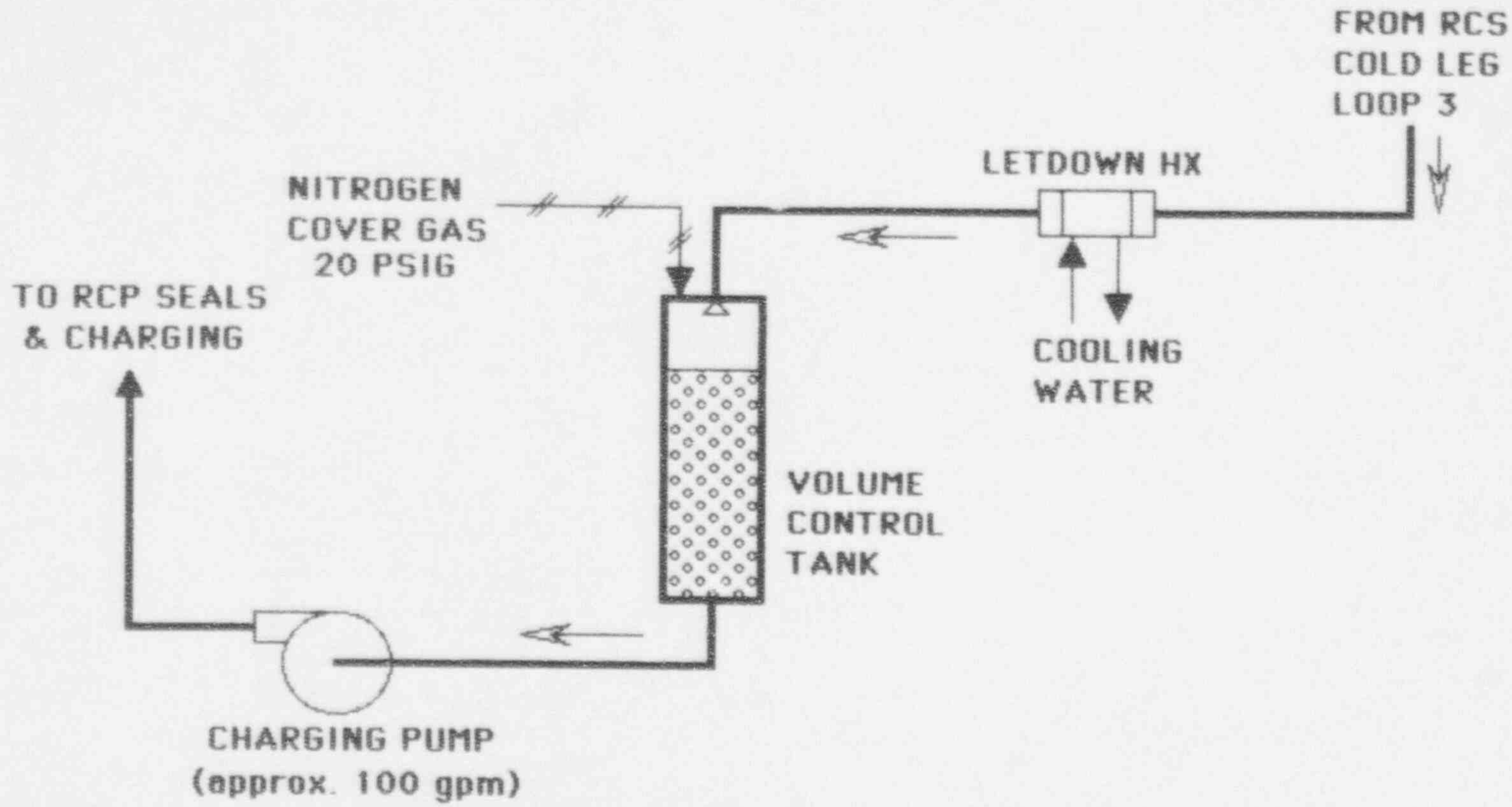
  - REACTOR VESSEL LEVEL INDICATION SYSTEM NOT MONITORED.

- CONCERNS
  - MINIMUM WATER LEVEL SLIGHTLY BELOW TOP OF HOT LEGS, A LITTLE OVER 5 FEET ABOVE TOP OF CORE, 10 INCHES ABOVE MID-LOOP LEVEL.
  - CONDITION OF PLANT UNKNOWN TO OPERATORS.
  - CONDITION NOT COVERED BY PROCEDURES OR TRAINING.
  - CREDIT TAKEN FOR STEAM GENERATORS TO ALLOW REMOVAL OF ONE RHR LOOP FROM SERVICE.
- SUBSEQUENT ACTIONS
  - TVA MODIFIED SHUTDOWN PROCEDURES.
  - INFORMATION NOTICE 94-36 ISSUED 5/24/94.
  - NRC STAFF EVALUATING IMPLICATION OF EVENT IN CONTEXT OF SHUTDOWN RULE.



RCS SIMPLIFIED
FLOW DIAGRAM
PZR Relief Tk
PORVs
PRESSURIZER
Head
Vent
Loop 2
Loop 3
Loop 1
Loop 4
RCP
RCP
RCP
RCP
RHR Return
RHR Return
RHR Return
RHR Return
RHR Supply
Normal
Letdown
(Hot Leg)
(Cold Leg)
Normal Charging

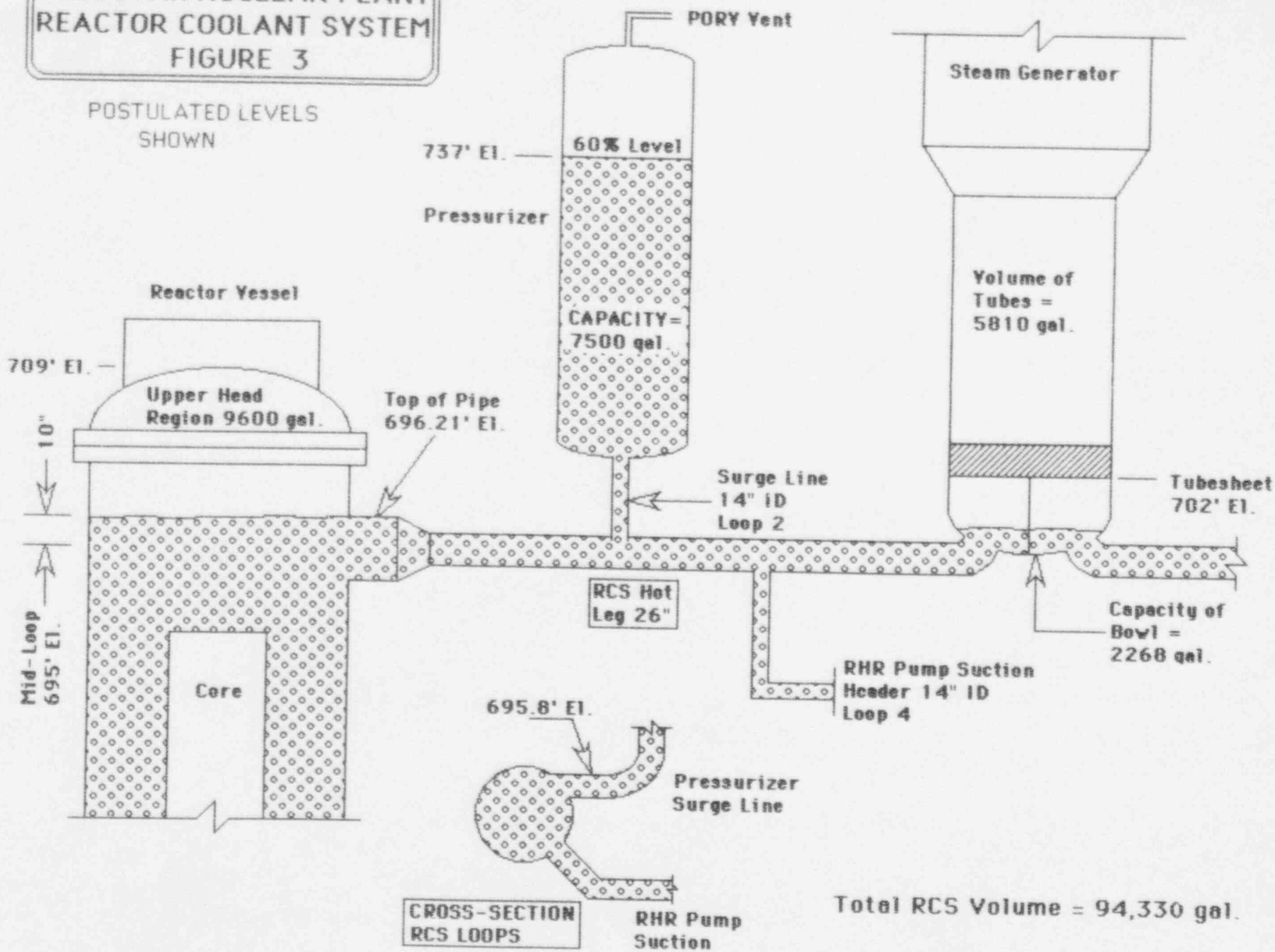
FIGURE 1

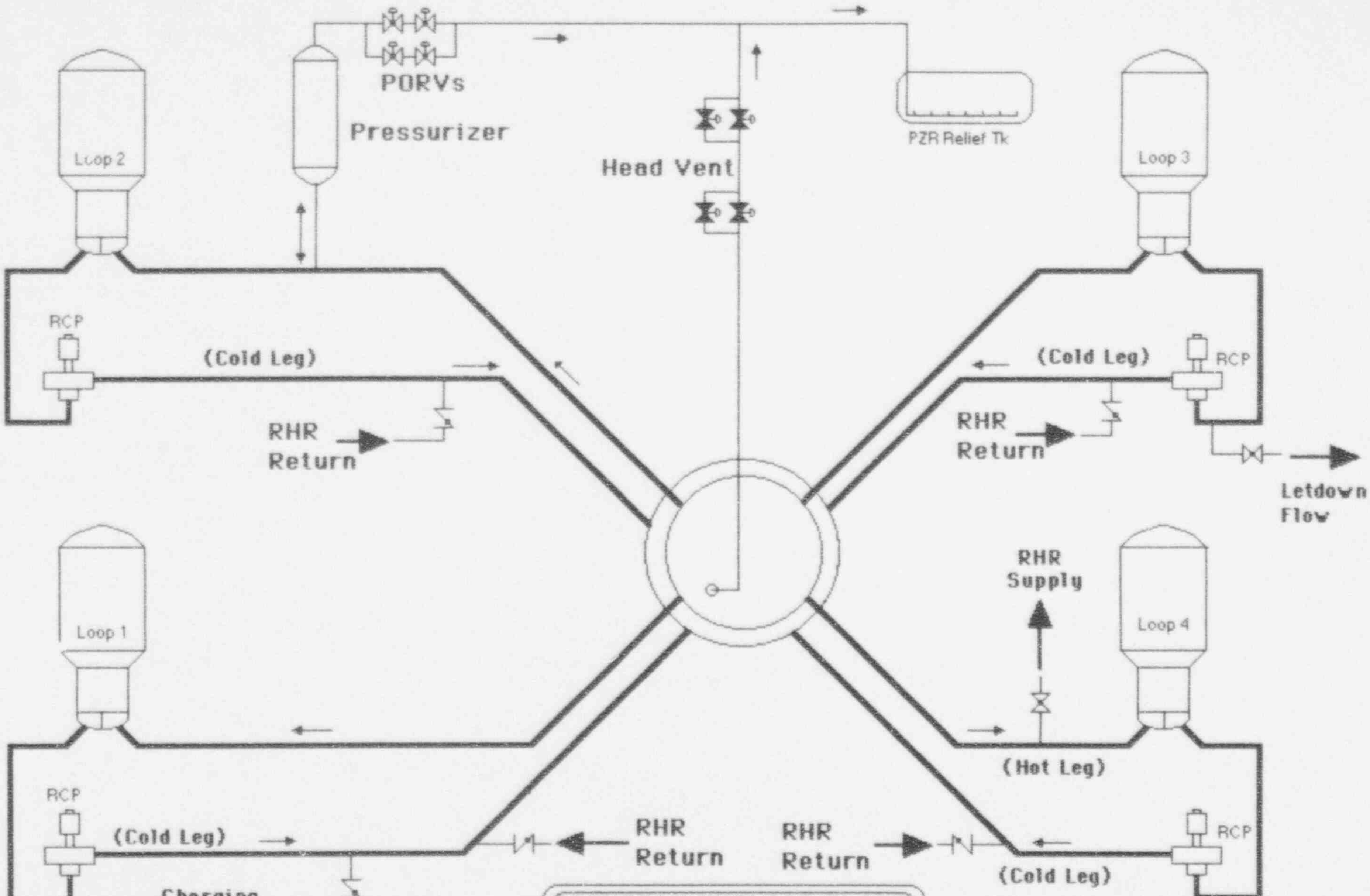


SEQUOYAH NUCLEAR PLANT
LETDOWN & CHARGING SYSTEM
FIGURE 2

SEQUCYAH NUCLEAR PLANT
REACTOR COOLANT SYSTEM
FIGURE 3

POSTULATED LEVELS
SHOWN





SEQUOYAH NUCLEAR PLANT
REACTOR COOLANT SYSTEM
FIGURE 1