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SUBCOMMITTEE ON MIDLAND PLANT UNITS 1 AND 2

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON MIDLAND PLANT UNITS 1 AND 2

Nuclear Regulatory Commission
Room 1046
1717 H Street, N.W.
Washington, D.C.
Wednesday, June 2, 1982

The Subcommittee meeting convened at 4:00 p.m., pursuant to notice, D. Okrent, Chairman of the Subcommittee, presiding.

PRESENT FOR THE ACRS:

D. OKRENT
W. MATHIS
D. MOELLER

ACRS CONSULTANTS PRESENT:

W. LIPINSKI
H. EPLER

DESIGNATED FEDERAL EMPLOYEE:

DAVID FISCHER

NRC STAFF PRESENT:

D. HOOD
R. HERNAN
W. JENSON
J. MASADAS
J. SLADE
R. TEDESDO
L. GIBSON
T. DUNNING
B. HAMM

ALSO PRESENT (continued):

J. TAYLOR
T. BALLWEG
E. ADENSAM
T. SULLIVAN
B. HARSHE
J. KENINGER
J. PASTOR
J. ZABRITSKI
H. SLAGER
R. POLICH

P R O C E E D I N G S

MR. OKRENT: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Subcommittee on Midland Plant Units 1 and 2. I am David Okrent, the Subcommittee, Chairman. The other ACRS members present today are Mr. Mathis and Mr. Moeller, and one or two other members may join us later. Also present are two ACRS consultants: Mr. Lipinski and Mr. Epler.

The purpose of this meeting is to continue the review of the application of Consumers Power Company for the license to operate Midland Plant Units 1 and 2. Specifically, we will discuss those items which we did not have time to get to during the May 20-21, 1982, meeting in Midland, Michigan.

The meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act and the Government in the Sunshine Act. Mr. David Fischer is the Designated Federal Employee for the meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on May 26, 1982. A transcript of the meeting is being kept and it is requested that each speaker first identify himself or herself with sufficient clarity and volume so that he or she can be readily heard.

We have received no requests for oral statements from members of the public for this meeting. Similarly, we have received no written statements from members of the public for this meeting. Two written statements relating to the ACRS operating license review of Midland were received today for consideration by the full Committee on Friday.

I might note that Mr. Fischer advises me that sometime in the not too distant future there may be a larger room that will become available, at which time if there are still standees we will move to it. But for now we will proceed here. We apologize for any inconvenience.

There is an agenda that has been prepared for today's meeting and I think we will proceed right to it and call upon the NRC's representative, Mr. Hernan.

MR. HERNAN: Mr. Chairman, Mr. Hood will cover this portion of the agenda.

MR. OKRENT: All right.

MR. HOOD: Mr. Chairman, the open items remain unchanged from the discussion that we presented at the last Subcommittee meeting on the 20th. I can go through or I can answer any questions the Committee has on any particular items, but unless there is an indication of that I would prefer not to do it.

MR. OKRENT: Well, then, why don't we just proceed to the next agenda item, which related to questions on the SER that we could not get to at Midland. Let me start off by asking something to see if I understand one of the open items.

I think there is one called Natural Circulation Cooldown Analyses and in my copy of the SER it says 5.9.4.2, which I must confess I had trouble finding 5.9.4.2.

MR. HOOD: That is correct. That is an error.

MR. OKRENT: Could you tell me first what it is if it is not 5.9.4.2; and then, secondly, tell me what the issue is?

MR. JENSON: Excuse me. I am Walter Jenson from the NRC Staff. This particular section you are looking for is 5.4.1 -- 5.4.4.1 -- and it is under Required Tests and Analyses in the last section of that -- the last subsection of that section, page 5-33.

MR. OKRENT: What is the open issue in this regard?

MR. JENSON: The answer is that we would like to see calculations by the Applicant and also tests showing that the reactor system can be brought down to the cold shutdown conditions in a manner that we can clearly understand. We just have not seen this analysis yet.

MR. OKRENT: Is this confirmatory or open?

MR. JENSON: Confirmatory it should be.

MR. OKRENT: Well, let me see again what I have been doing wrong.

MR. HERNAN: Mr. Hernan from the Staff. This item did end up as an outstanding item or an open item. We felt, due to the importance of demonstrating this capability, that there was one issue which the Staff really had not totally concurred without seeing confirmatory information. So it is listed in the report as an outstanding item.

MR. OKRENT: Would you again tell me what you think the issue is that is outstanding?

MR. HERNAN: The issue is for the Applicant to demonstrate his ability to cool down the plant.

MR. OKRENT: Under what circumstances?

MR. HERNAN: Well, under basically all conditions, including accident conditions.

MR. JENSON: This would be just a natural circulation cooldown to achieve a cold shutdown condition in a fairly rapid time -- 36 hours I think the requirement is.

MR. OKRENT: Is that the issue? I am trying to understand what the Staff thinks is the issue.

MR. JENSON: Yes.

MR. OKRENT: The reason I am curious a little bit is in the last Subcommittee meeting I attended today --

(Laughter.)

MR. OKRENT: There was some discussion of an interest in what is called MOD V or SEMISCALE and we were told that the Licensing Staff thinks there is a need for understanding natural circulation in this type of reactor under certain small break LOCA conditions. Now that does not seem to be what is said here, so I am trying to understand: Is it a concern of the Licensing Staff? If so, was it mentioned in the SER? If it was not mentioned in the SER, why was it not mentioned in the SER?

MR. MASADAS: My name is Jerry Masadas. I am with the Reactor Systems Branch. The two are different issues, or different areas. The one in the SER for which natural circulation is mentioned is a follow-up to the standard review plan requirement, in RSB Branch Position 5-1, which requires each Applicant to demonstrate either for his plant or for a referenceable plant that natural circulation conditions to cold shutdown involving areas such as boron mixing is viable, and we required such a test on all plants.

MR. OKRENT: I understand that, and that is what is in fact on 5-33.

MR. MASADAS: I think in the meeting you had this morning on SEMISCALE that my perception of the need for the experimental data is to help the Staff in responding to the continuing questions that are coming from different arenas such as Congress and in the private sector and in the hearing boards to help us answer questions of an understanding of the B&W machine in small break LOCAs and natural circulation.

I do not want to oversimplify a fairly complex issue with many facets, but basically that is what it is; and unfortunately the individual, if they could get more eloquent into addressing it, is in Paris, France, this week, Dr. Brian Sharon, with Dr. Ross from Research. But the areas, for an example, where SEMISCALE would help us understand is in, as you are aware, operator guidelines that are being generated within the next year or two. There will be an evolution in emergency procedures out in the industry. Multiple failures, which is addressed in these guidelines, at times there are questions that are being asked that the answers from the experimental data would help us to provide an understanding of some of the answers and we want to make sure that we understand what the operator is going to see for these different scenarios in SEMISCALE, which would help to do this.

MR. OKRENT: Were you present this morning when this matter was discussed?

MR. MASADAS: No, sir.

MR. OKRENT: I would think it was a completely different topic from what you have told me now from what I heard this morning. In fact, from what you have just said, I have no understanding of the issue raised this morning.

I would suggest that you do a few things: First, I think the Staff had better all caucus and find out where they think this question of natural circulation and the presence of small LOCAs stands as a safety issue. You suggested in what you said that it is just outside pressures from some people who are trying to ask you to look at things or whatever. That was not the sense of the meeting this morning.

There seems to be some concern that at least under some seismic small LOCA you have interruption of natural circulation, repeated interruption; and there was a technical question being raised. So again I think we will want to know just what it is the Staff thinks about this. And I would like to know why it was not in the SER and why it was not reported to the Subcommittee at this time if you missed it for last week or whenever it was --the weeks seem to run together --when we were in Midland.

MR. TEDESCO: Bob Tedesco from the Staff. Dr. Okrent, we were not at the meeting this morning, but we certainly will follow through with it and get a better understanding of what went on and how it relates to the Midland plant.

MR. OKRENT: Dr. Mattson's name was used this morning, so it was not just the people from the Research Office that were mentioned.

Let me ask you whether the Subcommittee Members have questions on the SER, the agenda item we are on now, on things that you would like to raise that are not already agenda items.

(No response.)

MR. OKRENT: Well, while you are looking let me ask the Staff: If I understand correctly, the diesels are just about at the PMF level plus or minus something and I am not sure which it is. Is there any question of desirability for access to that area during a flood time? Or are there any other things besides protecting them per se? I am trying to understand the situation.

MR. HOOD: Daryl Hood, NRC Staff. The plant grade at Midland is such that the concern for the diesels would be the wave run-up problem. The Applicant has provided removable barriers at the entranceways to the diesel generator building to provide the additional height that is needed to that structure for PMF protection. That design takes into account the settlement of the structure that has occurred and that is projected to occur.

MR. OKRENT: Again, if you had a flooding condition, would you have any reason to want to have access to the diesel buildings? And if so, would there be a problem having access?

MR. HOOD: The PMF would not preclude access to the diesel generator building.

MR. OKRENT: One would wade through the water or what? I am just trying to envisage what would take place.

MR. HOOD: Yes.

MR. OKRENT: You would not worry about opening the doors?

MR. HOOD: Again, it is a wave runup that is occurring. The removable barriers as such do not preclude entrance to the door. They form like a small dam across the bottom so you can step over it.

MR. OKRENT: So you do not think there is any problem in this area?

MR. HOOD: No, I do not.

MR. OKRENT: Okay.

MR. MOELLER: In terms of flooding, have you looked or has the Applicant looked at what impact that might have on evacuation of the nearby chemical plant? And if you had an accident concurrent with flooding, what does that do to your emergency plan?

MR. SLADE: Dr. Moeller, Jerry Slade. I do not know that we have specifically looked at the impact of the flood on the evacuation plan requirements for Dow. But Dow is lower, generally, than our entire site. I think you may recall from the site visit that when you are standing on top of the dike, on top of the 634 elevation, you are looking down on Dow Chemical Company.

I would think that they would have to evacuate long before that and shut the processes down just because of the physical constraints they have on operating their facility. They would be under water.

MR. OKRENT: I think you may have mentioned in the previous Subcommittee meeting, but how do you expect to resolve the outstanding open item on turbine missiles? Where do you think that is going to come down and why and how?

MR. HOOD: You have a handout that the Staff has provided to you that responds to the questions asked of the Staff.

MR. OKRENT: I see. Okay. So if I read that I will find this one?

MR. HOOD: You will find the first question and answer going to that subject.

MR. OKRENT: Okay. I will read it, then.

Can I ask you another question? On page 6-13 of the Safety Evaluation Report there is a reference to an NPSH requirement and the calculation of it and so forth. I do not know really anything about how one determines these NPSH requirements in detail.

What is the accuracy with which one knows an NPSH requirement? In other words, it says here the requirement is 19 feet where you have 24 and 18 feet where you have 21. It sound like there is margin. But what is your opinion about the accuracy?

MR. TEDESCO: The calculation of NPSH is based on Reg Guide 1, where you get considerations of the pump characteristics, the elevation of the pump to the static head, and the volume losses, and then the saturation conditions that exist as a function of time. So that is how, together with the calculation of TRAC, we have the containment response.

MR. OKRENT: I am sure the people can estimate the gravitational effects quite well. To the extent that there are pump effects, are these very well known or have they been confirmed in some other way?

MR. TEDESCO: Usually the manufacturer specifies what the pump characteristics are, and that would include the NPSH requirements. And what we would do is perform the confirmatory calculations that would verify that they had met the NPSH requirements.

MR. OKRENT: Suppose one lost containment integrity because some purge valve or something was left open. Would that affect the availability of adequate NPSH?

MR. TEDESCO: If I remember the way the calculation went, it would follow the pressure and temperature effect in the water along with the containment, but no net credit would be given to a thermal condition like that. They would not be given credit for the additional pressure of the containment. That is a provision of Reg Guide 1.1.

MR. OKRENT: Is that correct? I knew it was the case the way you have applied it for BWRs. I was not sure for PWRs. That is the case?

MR. TEDESCO: I think TRAC is here.

MR. OKRENT: Fine. That answers that question.

(Pause.)

MR. OKRENT: On page 6-14 there is some discussion of containment isolation reliability. How does the Staff judge that this is good enough? Is there some kind of reliability analysis that the Staff has the benefit of?

MR. TEDESCO: As far as the containment isolation valves there are no firm requirements on reliability criteria.

MR. OKRENT: On top of page 6-15 it says: "The Staff concludes that although the isolation provisions for these lines do not fall into any of the four combinations listed in GDC-55," et cetera. Now I was just wondering whether you ever do reliability assessments to see whether in the first place what GDC says is good enough and, in the second place, whether you are accepting something and instead whether it is good enough or equivalent or whatever. Or don't you think that the reliability assessments would be accurate enough to be meaningful?

MR. TEDESCO: Most of the valves are selected on the basis that they have to meet the general design criteria as far as their quality aspects go. I think when some of the earlier evaluations were done on risk assessment the overall conclusion for reliability was done, and that included some consideration of reliability, but I am not aware that this was done explicitly on Midland.

What we are looking for mostly here is the arrangement and the configuration of the isolation capability.

MR. LIPINSKI: I have a question on the vent and purge valves.

MR. OKRENT: Go ahead.

MR. LIPINSKI: There is a signal that says they will be closed with 4 psi within containment. Are those valves qualified to close against the 4 psi pressure head when the volume is coming through those lines?

MR. TEDESCO: They would have to be qualified for the service conditions they are required to operate under.

MR. LIPINSKI: I have asked that question on other plants and I never get a satisfactory answer because the trip signal is in there and nobody can ever say that they are definitely able to close with a 4 psi pressure inside containment.

When those valves are opened and that containment gets up to 4 psi and triggers the signal, can they close when the volume is coming through those lines?

MR. GIBSON: Lou Gibson from Consumers Power. The specification requirements are that the valves be able to close against the accident conditions in the containment, which would be about 60 pounds in this case, not just 4.

MR. LIPINSKI: Okay. Thank you.

MR. OKRENT: On page 7-13 there is a discussion of the feed only good generator system for which the acronym is FOG. Has the Staff reviewed the FOG's system to see that it does not have any failure modes which lead to an adverse effect?

MR. TEDESCO: Is Tom Dunning here? That is his area.

MR. DUNNING: Tom Dunning, NRC Staff. We looked at the FOG system as far as single failure and things like that, but I cannot specifically say that we looked at an aspect of an inadvertent failure of it causing a problem.

As I recollect, about the most you would g
for any failure that you would randomly isolate one

steam generator, but this is the same action that you would cause if you had a faulted steam generator and you were trying to isolate it. I am confident that there are no failure modes that would end up isolating both steam generators.

MR. OKRENT: You are confident because there was an FMEA done or why?

MR. DUNNING: Well, just because of my familiarity with the system and the way the system is designed. I do not see that it would -- there would be failure modes in there. The worst it could do is cause an inadvertent isolation of the steam generator which you would then deisolate. But I do not see that -- I am sure that the review took into account that it does not fail in a manner so that both steam generators could be isolated due to any single failure.

MR. OKRENT: You keep bringing in the term "any single failure." And I am not really sure that that should be the basis by which you look at this because we are having events all too often where there is more than a single failure going on.

MR. DUNNING: Well, in that you can isolate a steam generator with the FOG systems, there is a valve you can close that will cause the isolation. If you get multiple -- you only have two steam generators. If you get the right two single failures at the wrong time it will isolate both. I mean, you can always pick a point if you can take an isolated A steam generator with a signal, if that occurs inadvertently on one steam generator and you get the same thing on the second steam generator you can say that is two single failures and that isolates both steam generators.

But it almost falls out that if you want to pick two failures you can always pick two failures somewhere in the system that would isolate both steam generators, but those are not the likely type. It would be hot shorts, or something like this. It is not something that would fall out of something operating inadvertently.

MR. OKRENT: If we have an unexpected failure mode on a system intended to look for steam breaks, steam line breaks, and it led to an effect on the availability of decay heat removal other than we wanted recently, my memory tells me it was a B&W plant. Maybe Mr. Taylor, who is here, can refresh my memory.

(No response.)

MR. HAMM: Bob Hamm, Consumers Power Company. I am not directly familiar with the event you are speaking about. I know that in a previous design that we had at our plant earlier, if both steam generators depressurized below 600 pounds we would isolate both steam generators. We feel that with the good steam generator system that we have incorporated into our plant we think defeats that and only one steam generator can be isolated at a time.

MR. OKRENT: The only reason I bring up that prior example is just that sometimes these features do not work only in the way they were intended. I was trying to understand whether the Staff consciously tries to see whether the Applicant has, or somebody, to see whether you could have some undesirable failure modes under situations other than just the usual single failure criterion.

Well, I will leave it as a thought for now. I might ask if they have done an FMEA on the FOG system, including more than a single failure.

MR. TAYLOR: (Nods in the negative.)

MR. OKRENT: There is a question Mr. Ebersole usually asks and I will ask it.

(Laughter.)

MR. OKRENT: Namely, are there any steam line failures that would be awkward in that the valves that you are relying on for isolation might be subjected to dynamic forces for which they are not qualified? Is the question clear?

MR. BALLWEG: Tom Ballweg. So far as we can identify, there are no valves that could be subject to transients that are unanticipated. We have been extensively through the main steam system looking at break locations and valve actuations that are required.

MR. OKRENT: So you are considering valve locations both upstream and downstream of breaks and examining the actuation of these valves under the dynamic forces?

MR. BALLWEG: Yes.

MR. OKRENT: Okay. Well, I will let that go on back for now. Are there other questions that arise from the SER? Anything the consultants have that is not on the agenda?

MR. EPLER: Mr. Chairman, with regard to the FOG question, I would suggest that the question might be phrased in this manner: Rather than to rely on the single failure approach, to use the classical example of a failure in one unit but the other unit by mistake being serviced in such a way that they are both unavailable. This has, because it has happened so many times and has a fairly high probability, we should be interested in the consequences.

MR. DUNNING: Would you like to have a response?

MR. OKRENT: If you have one, please give it to us.

MR. DUNNING: Tom Dunning again. One thing I would like to say about aux feedwater control systems, when the task action plan requirements came out to upgrade the aux feedwater control systems, it addressed specifically requirements using requirements specifically for protection systems, calling out some specific references to IEEE 2.79 with respect to the automatic initiation of the aux feedwater systems.

And during our review of the aux feedwater systems we have paid quite a bit of attention to not only the circuits that are provided there in the classical sense to automatically initiate the systems, but as well as to look at systems from the standpoint of failures, what could happen inadvertently, the aspects of conditions that might initiate something when you do not want it, and looking at the controlability after the system is initiated, the impact related to the full scope of the problem of where things could go wrong that would possibly negate this vital system for maintaining core cooling.

So in that general statement what I am trying to say is that I think we have gone into quite a few aspects of all the controls related to aux feedwater to see if there are any areas where problems could be developed that would make the system unavailable, and not just look at do you want to have an automatic initiation system and looking at it in the classical sense -- does it have the redundancy and the other features -- alone and not look at other aspects.

But I think we have been pretty thorough in our view of the system from the standpoint of failures that could negate its capability to provide core cooling.

MR. OKRENT: But if I understand correctly, there has not been an FMEA done on this particular part of the system. Is that right?

MR. DUNNING: The Staff, I would say, did not perform that, but it does take -- and just going through it looks at failures and what the consequences can be. So it is not a documented type of a failure modes and effects analysis that tries to go through every single component, but that is really foremost in our review process as we go through all the electrical drawings and we got into the schematics with the system and the logic and it was a pretty thorough review right down to the schematic level.

MR. OKRENT: All right. Well, if there are no other questions at the moment on the SER, why don't we go on to the next agenda item, which relates to --

I am told that the room next door, which is larger, is available, so before going on to the next agenda item why don't we move.

(A brief recess was taken.)

MR. OKRENT: We will reconvene the meeting. Before we go on to the next agenda item, since the sound has been turned on I had a chance to look at the response that the staff wrote to the questions of turbine missile condition. As I understand it, if you were to use the standard review plan you would come up with estimates of probability of unacceptable damage on the order of 1×10^{-5} per reactor year. If you were to take General Electric's calculated probability calculation for missiles, this number would change by on the order of four orders of magnitude in a smaller direction.

I am trying to understand on what basis the staff expects to proceed, using the standard review plan. If it doesn't use it, on what basis will it deviate from the standard review plan? Does it think calculations like 10^{-9} per reactor year, 10^{-7} per year of this sort of thing are valid, and why? Can someone help me?

MS. ADENSAM: Dr. Okrent, we had made arrangements with the staff to be down here later on the bolting issue. Mr. Zabritski would be better able to respond to those questions for you. I notice that feedback on these items was a later agenda item. If we could hold it until then, he would probably be the best individual to discuss this with you. My name is Adensam, Eleanore Adensam of the NRC staff.

MR. OKRENT: We can wait, but I am trying to get some feedback on which item was the later agenda item.

MS. ADENSAM: Responses to questions that you had asked at the May 20th meeting.

MR. OKRENT: All right. And the staff will be here later to address that agenda item?

MR. ADENSAM: It is my understanding they will, yes, sir.

MR. OKRENT: Good, okay. Let's then get on to items from the previous ACRS letters. Let me ask whether the subcommittee members would like to go through these one at a time or would you want to have specific questions on specific ones? You will recall that after the CP letter was written on Midland, the ACRS wrote one or two more letters on it, and one of these in fact identified several matters which were what were then called generic items.

I guess let me ask the subcommittee members to look at these and see which of these they feel they might want to address to the staff or the applicant as questions, and whether they would want to pursue that status in any way.

(No response.)

Let me ask the staff a question about one of these while the subcommittee members are looking at the others. There is an item called environmental qualification of equipment, and as noted, this was raised at least back in January of 1970 at the Palisades review. What is the status of this item for Midland, and on what basis did the ACRS assume it was in satisfactory shape?

MR. HOOD: I am not sure at this point in time that the subcommittee should assume that. The status of the review of the environmental qualification of equipment is that it is ongoing. The status of the staff's evaluation of the Midland program for environmental qualification of mechanical and electrical equipment is discussed in OL SER Section 3.11.

As noted in that section, the review would be performed using the guidance of NUREG 0588 and staff position on environmental qualification of safety-related electrical equipment. The review is continuing. Upon completion it will be addressed subsequent to the SER. The applicant provided a revised submittal on April 30, 1982. The staff anticipates an audit in mid-June of 1982.

The seismic equipment qualification program is addressed in OL SER Section 3.10. As noted there, the review is continuing. The applicant's seismic report is to be submitted in July 1982, and an audit of our seismic qualification review team is scheduled for September 1982.

MR. OKRENT: Well thank you for reading aloud or into the record what we had, but you have not added to my own perception on what basis the ACRS is supposed to assume this matter is or will be satisfactory for Midland. You have criteria for this which you expect to be met. Are you going to come back to the committee in some generic way and say that this is what we will require for Midland in the future? Just what, in your opinion, is the status of this item? This is not exactly a new item.

MR. TEDESCO: Dr. Okrent, you are right. It is not a new item; it applies to both the operating plants and the plants that are going through for an OL license. The requirement has been spelled out in the Commission order a couple of years ago, based on NUREG-0588 that deals with the conditions for qualifying equipment that must survive an accident. That is applicable to all plants, and a special review effort is going on, conducting a review for the staff.

MR. OKRENT: Well, what is the nature of the situation, in your opinion? Is it that they have done a qualification program and you just need to review whether everything is okay? Or there are some things that one does not even know how to qualify? Or somewhere in between? I am trying to understand.

MR. TEDESCO: In Midland it is open, we haven't finished the review. But generally the experience has been to verify that the equipment purchased does, indeed, meet the environmental qualification requirements.

MR. OKRENT: It does meet it?

MR. TEDESCO: Yes. Some of it is very easy to find; some are more difficult, but even in some instances people even had to retest the equipment to requalify it. But those verified that all the equipment had been verified. It is an audit that will be done by the staff. The staff doesn't go through every piece of equipment.

MR. OKRENT: Why is this still an outstanding issue on Midland, since this is not something duly identified?

MR. TEDESCO: I guess the review team just has not gone to Midland yet. They don't have all the documentation available yet. It is not unique to Midland.

MR. HERNAN: We have had a number of meetings and a number of what I felt were very productive meetings on this subject. I think -- I am not sure of the exact date of NUREG-0588, but firming up the criteria I feel will build up the review. Resuming the Midland plant review after the TMI-2 events, certainly there was a period where this review was not very active.

I believe from my observations at the meeting that the applicant understands the requirements, they understand our criteria, and have laid out a program which appeared at that time to be in favor or favored by the staff and gives us a certain amount of confidence that the requirements would be met.

We have a representative, whom I believe is coming a little later on during this meeting, that will be in a little better position to get into some of the technical things that they found. The program has been presented to us. The staff has found their program suitable to the point of actually scheduling the audit, which would not have been done if we had not felt their program was on the right track.

From that standpoint, I think it has been a very difficult process to list all the instruments we are talking about, to lay out a program for each category of instruments, and certainly there are vendor-applicant interrelations that we have no control of insofar as actual testing and verification.

MR. HOOD: I would state it a little bit differently. I would say that a significant part of the reasoning is that it requires feedback. The applicant has to get feedback from their particular vendor on which option he will elect to qualify that equipment. So the timing process is such that we would get it at a stage that is geared to the construction process. The ordering of equipment and the applicant-vendor relationship. It is a rather massive effort -- two rather large volumes of documents documenting the qualification of various equipment.

MR. LIPINSKI: There was a May 5th subcommittee meeting on this, and there is a rule coming out on qualification. I came in late for that meeting because I was in the CRBR meeting. I don't know what the date is for the rule to come out, but one of the comments that came back on the draft rule was the fact that the NTOLs were not adequately covered in terms of how they are supposed to respond to the rule when it is issued.

MR. TEDESCO: In the interim, we have a memorandum and order to cover the operating plants in the interim.

MR. OKRENT: The staff still has some research going on, don't they, on whether certain equipment will behave or misbehave under accident conditions? Equipment that you normally find inside containment?

MR. TEDESCO: That is my understanding, yes.

MR. OKRENT: Well, I guess I am trying to figure out what one would say if you didn't say this matter will be resolved in the future.

MR. SULLIVAN: Terry Sullivan, Consumers. If I could point out this matter is on the agenda later this evening.

MR. OKRENT: I agree, but I think we are going to get into a more detailed understanding. But I am not sure we are going to see a resolution today. Are there questions on other items that members would like to raise?

MR. MOELLER: Well, in the items on instrumentation to follow the course of an accident, on reading the discussion it implies that this was restricted primarily to the control of the buildup of hydrogen within containment. Why is it treated in such a restricted sense?

MR. HOOD: Dr. Moeller, the particular response went to the way that the Hutchison Island matter of March 1970 was written, and the concern that was expressed in that record. The instrumentation to follow the course of an accident was much broader than that item and will be discussed elsewhere.

MR. MOELLER: Most of it will be covered under post-TMI requirements?

MR. HOOD: Yes, as you will note in the third paragraph of that requirement. It is handled by references to those sections, to the post-TMI requirements, and Reg Guide 1.97.

MR. MOELLER: Will this plant, for example, comply with the reg guide? Comply might be the wrong word, but will it pretty much correspond with what is recommended in Reg Guide 1.97?

MR. HOOD: Yes.

MR. OKRENT: Are there questions the subcommittee wishes to raise on other of the listed items at this time?

(No response.)

MR. OKRENT: Well, I guess not. We can come back to it.

MR. MATHIS: Yes. I would just move on.

MR. OKRENT: All right. This, then, would get us to the agenda item 5, methods to reduce common cause failure, including systems interaction studies and any changes in design that resulted from experience in the nuclear industry. I assume we have a presentation by the applicant?

MR. MOELLER: While he is coming up, I had a question. We had been provided the NRC staff's responses to questions by the ACRS subcommittee during the meeting of May 20th and 21st, and offhand, it looks like the staff has done a very good job of responding to each question that we raised. Do we have a similar document from the applicant?

MR. SULLIVAN: We have not provided a written response. We have a presentation on the specific question on the system draining and flushing.

MR. HARSHE: My name is Bruce Harshe, I am the head of the plant control section for Consumers Power Company. I am going to discuss method to reduce common cause failures. If I could have the first slide, please.

(Slide.)

Common cause failures, which we will define as systems interactions from here on, I have broken down into three areas that we have been investigating and have been addressing. First of all, the spatial interactions, which of course, is the coupling of system by virtue of their proximity to each other. That is, if something were to happen to other systems, its reaction could impact another system. Here I am talking about a physical type of interaction.

The second type of interaction that can occur is that of a functional interaction in which two systems may be coupled together through the process, and in so doing, if one were to fail in some manner, it could impact another process that it is coupled directly to. For example, cooling systems.

The last one is the human interactions. Here I am going to refer to it as induced human errors, in which case the operator, through misinformation an erroneous information, instrument error, what have you, the impact has led to him making a mistake and causing some adverse interaction that was not foreseen. Could I have the next slide, please?

(Slide.)

First I would like to address the spatial systems interactions. We have broken these down into two general major categories. The first one is the one being addressed primarily by our plant walkdowns of the proximity seismic II/I flooding and HELBA. By "proximity" I am referring to systems being close to each other such as adjacent piping, adjacent cable trays, piping relative to cable trays, instrument lines in the area and what is in the immediate area of them.

General criteria here would be, for example, that of a pipe which could swing and hit a safety-related piece of equiment in the area. That would be an example of a proximity. I am talking here about something side by side.

The second here is seismic 2 over 1, is something not seismically supported, located physically above that of the seismic system, such that if you were to have an earthquake, the non-seismic may fail and, in fact, fall on the seismically supported one, which was not designed for this additional load and which, of course, would lead to additional failure also. We do a walkdown on those.

The third one is that of flooding on the walkdown. Here we are looking for something such as rupture of a pipe, the impact of the rupture of a non-seismic pipe, for example, or the inadvertent actuation of the fire protection system. These are purely examples, of course, they are not inclusive.

The last, of course, is the HELBA where we are looking for physical impacts, jetting actions, pipe whips. What type of impacts could -- if you have a failure of the system, what could you run into? What could the consequences be?

(Slide.)

There are additional walkdowns done at the plant which contribute toward the spatial -- covering the entire area, or attempting to close in all the area of the spatial systems interaction. We have, for example, the thermal growth and the stress. In reality, these are performed as one walkdown, but they are looking at stresses as one in which we look to verify that the plant as built was as designed. We verify that the hangers are in the right places, that type of thing. In addition, while it is in the cold condition we verify where it is anticipated that movement would be greater than one inch after heatup; that in fact this spatial displace does occur, that we do we do have the clearances.

Then once the system is heated up, the system is checked also to verify that your snubbers or your hangers or the piping itself was not driven into some other system.

Then, of course, you have the fire protection walkdowns for comparison to the fire protection criteria. And of course, then finally, there are the turnover systems. Systems turnover in which the walkdown -- they system is inspected for its conformance to the actual design, and again, as a last quick walkdown for problems that can be seen which would impact the actual startup of that system.

(Slide.)

MR. LIPINSKI: Would you clarify the last one? Is that when you are commissioning a plant or is that during normal operation?

MR. HARSHE: The turnover walkdowns would be performed as individual systems are turned over from the construction phase over to operations to be bumped or to be tested for the first time.

MR. LIPINSKI: Okay. That is once in the plant lifetime, and does not apply to routine operations?

MR. HARSHE: Not during the routine operations. However, should there be a modification, of course it is walked down.

MR. OKRENT: What is done under thermal growth, again?

MR. HARSHE: Thermal growth is the part of the stress walkdown in which after the system has been heated up, you verify that the heat did grow in the manner it was predicted to, and in so doing, there is not a movement of a hanger support.

MR. OKRENT: Right. Where do you pick up spatial interactions which might occur via the heating and ventilating system? For example, heat in one room getting into another room, and so forth?

MR. HARSHE: Heating in one room going into an adjacent room. Well, the actual ducting is covered under the proximity and also in the II/I mixture that the ducting, the safety-related ducting will withstand the actual conditions so that nothing is going to happen to that.

As to the concern from, say, one location to another like a room or the adequacy of the HVAC system, that would come under design and function which I will be addressing in my next slide.

MR. OKRENT: In your look at spatial interactions, about how many man months of effort, roughly, was involved?

MR. HARSHE: The actual walkdown of the first floor have not started because of the construction of the plant. That is, it is necessary to have these rooms essentially complete prior to the walkdown. The estimates for the man hours -- let me -- one moment, please.

MR. SULLIVAN: Ten man years.

MR. HARSHE: Ten man years for just the seismic II/I in the proximity.

MR. OKRENT: This is something to be done?

MR. HARSHE: We have completed the sections.

We have been doing some testing of our procedures, okay? Those sections have been done.

MR. OKRENT: Okay.

MR. HARSHE: If I could have the next slide, please.

(Slide.)

Under the functional interactions, we address these type of concerns through the design controls which are one of the major methods of controlling such interactions. Risk assessment, to a lesser extent; then of course control systems' failure evaluation, pre-op testing and operating experience review. The design controls, of course, are the internal controls exercised by Bechtel which, for instance, one discipline may design a system. Then that system is reviewed by a different work group that is working on other systems to verify that this first system does not impact one of the other systems and vice versa.

For the system-system interaction, as well as for proper design, if a group designs a system, that is reviewed within that same discipline by another group which had not been involved in the initial design phase. So this gives you an idea of the review processes it has been going through. We have then the conformance to the design criteria in the reg guides verifying that things have going been properly, and auditing is involved in the design process.

To a lesser extent, we have the risk assessment in which interaction dependencies can be identified and have been identified. This system, which was a logical progression of what systems interactions could occur, has been fed back into the design process. And it was touched on somewhat earlier in the PRA presentation.

The control systems failure analysis -- we do this by FEMA, for instance, of the ICS. You will be hearing a little bit more about this a little bit later. We look at the inputs to our system, looking for common mode type failures such as one instrument line, more than one transmitter coming off of it. The power supply failures are the classical.

The pre-operational testing -- here we are looking to verify the equipment can perform as designed. Such as when fuel is loaded, we verify that we can get to the safe shutdown condition, that the loads and temperatures of the equipment are as designed.

Last, we have the operating experience review. You are going to see this twice, both here and under the human interactions, in which we have had and continue to have a program where we are looking at industry experience such as the INPO documents, B&W's experiences with their plants, and CP Co's own plants to look at commonalities where it would be most fruitful to look at our own design.

MR. OKRENT: Have you made any changes in design of your own volition as a result of operating experience?

MR. HARSHE: The one that comes to mind immediately is at our own Palisades plant. That also came out in an I&E bulletin associated with a battery, a DC battery system being disconnected from the bus. We, in fact, now have incorporated that design change into the Midland design. So there is one example.

Most of our experience has shown up, though, in the human error factors where our primary impact has been to date. However, when the review is done, it is done with respect to hardware sensitized in that area.

MR. OKRENT: Has the risk assessment, incomplete as it is, so far led to any design changes?

MR. HARSHE: The one that was identified in our PRA presentation in which the concern with the service water was modified. The logic on that, to modify the second pump to isolate the non-critical header to eliminate the loss of cooling -- that is an example of where the PRA was involved.

MR. MOELLER: Have you made any changes on the basis of LERs? You said you worked with INPO.

MR. HARSHE: What we are doing is reviewing the SERs from INPO and using them as a primary filter. The number of LERs of course is quite large and a filtering mechanism is needed.

Okay, if I could have the next slide, please.

(Slide.)

Here I am talking about the induced human errors, induced human actions. We are addressing it in three primary modes. The first, of course, is operator training. In operator training we have at our disposal the mock-up that you saw on your plant tour.

We also have a plant-specific simulator. With this we can familiarize the operators with the seldom used procedures; we can also reinforce the proper operating techniques. Also, if an operating mode such as from the operating experience came up, it can be practiced on the simulator once the procedure changes are incorporated.

Control room design review is also an integral part of this to make sure the operator is not led down the wrong path. This was partially discussed a couple of weeks ago. Again, the use of enhancements such as functional groupings, mimics, labeling, computer graphics, any or all of these or any combination may be used, and this is what is being investigated for the optimum use of these.

Under this same heading, we are integrating the operator-panel interface. By that I mean in the control room review, we are looking at the procedures, we are integrating the two together so that you end up -- as opposed to a fragmented approach, okay, we are integrating the systems together.

Then we have the operating experience, and this is, again, the same input. Here what we are doing is identifying potential errors that the operator could be misled, and this information then is being fed into our training department, and this is stressed during our training process.

If I could have the next slide, please.

(Slide.)

So on balance, what we have is a program that has looked at three major divisions, okay, and we feel this has attempted to keep to an absolute minimum the potential for common cause failures.

You will notice that we have not really limited ourselves to simply the non-safety grade/safety grade interaction, but we have also included in here the safety grade/safety grade type.

That completes my presentation.

MR. MOELLER: Could there be a non-safety grade/non-safety grade interaction that might then affect the safety grade?

MR. HARSHE: Not that we have identified. However, in our walkdowns, for example, in our training for the walkdown teams, we are sensitizing these people to, in generalities, as to the types of interactions that they are to identify. If they identify in the room or whatever manner they are doing it, primarily this area, if they identify a problem that is non-safety/non-safety and they know that is a potential concern, that would be identified under those conditions.

The non-safety/non-safety leading to a problem, some of those things, we have that base covered potentially throught the PRA. Could I have that confirmed?

MR. MOELLER: Is that being looked at in the PRA,

MR. HARSHE: The question is, could a non-safety/non-safety interaction result in a safety concern such as in the PRA.

MR. KENINGER: My name is John Keninger from Consumers. Primarily, the mitigating systems that we are examining in the PRA are safety grade. We are examining the systems they are relying upon to operate which are also largely safety grade. There are also obviously some non-safety grade ones for offsite power, which is probably the leading one there. So the answer is yes.

MR. OKRENT: How does the program that you plan on systems interaction compare with what the staff have indicated in their discussions thus far on how to deal with that unresolved safety issue, particularly in connection with Indian Point? Have you followed that?

MR. HARSHE: Yes. Our system -- the approach that we have been taking covers the spatial systems interactions such as at Indian Point. And we are also -- we rely heavily on, from a theoretical standpoint, on the design controls as well as the input from our PRA.

And in that respect, we believe we have a program that is certainly comparable to what is already being done. Not identical.

MR. OKRENT: Mr. Epler?

MR. EPLER: I would like to refer back to a previous statement in which you observed that the DC system had been improved based on operating experience, and that this improvement had been carried on into the Midland system.

Now, the Midland system has several advantages over previous systems. My question is does this comply with the minimum requirements, or is it in excess of minimum requirements, and in what degree?

MR. HARSHE: It is in excess of the minimum requirements. If you -- you ask in what degree. Okay. As a result of the Palisades incident, the direction was to monitor breaker position. In fact, the modification we made would indicate whether or not the batter was disconnected from the bus, the battery bus, the DC bus, for whatever reason; whether it be a disconnect open, a fuse that blew unknowingly, whether it be that the breaker was open, whether you have some sort of a disconnect in the wiring lead to the bus. So in that respect, we have exceeded it.

MR. EPLER: Then the other improvements we have observed in the Midland system came about because of improved regulatory guide improvements requirements. That is, you have a larger size capacity battery charger; you have gotten rid of the bus tie breaker --

MR. HARSHE: Did you say that was a result of Palisades? Is that what you are asking?

MR. EPLER: I am asking is that a result of regulatory guide requirements?

MR. HARSHE: That would be initial design.

MR. EPLER: Yes.

MR. HARSHE: I don't think so. Let me confirm that.

MR. PASTOR: Jim Pastor, Consumers. Actually, part of our design was upgraded mainly for operator convenience. The specific I'm thinking of is the charger.

The other requirements I don't think we can answer yo really directly as to whether it was a result of regulatory requirements or not. We do try to follow those in the design like IEEE, but the design is more for operator convenience.

MR. EPLER: My question was not the additional charger but the capability of the charger to carry the load, and to charge the battery.

MR. PASTOR: As far as directly for the capability of the charger, that would be in response to the reg guide.

MR. EPLER: I see, okay.

MR. HARSHE: I would like to add that the Palisades one also carries the full loading and can recharge the batteries, even though they do have redundant chargers. So this would be more of a Consumers Power philosophy, I guess you would say.

MR. MOELLER: What sort of guidance does the staff provide you in conducting a systems interaction evaluation?

MR. HARSHE: We read their correspondence and then factor that, of course, into our thinking for our own program.

MR. MOELLER: But there is not a reg guide that offers guidance or something in the standard review plan? It is pretty much in a developmental stage?

MR. HARSHE: Yes.

MR. OKRENT: Why don't we go on to the next slide?

MR. LIPINSKI: Systems interaction, that comes into the classification of safety grade/non-safety grade interactions with ventilation?

MR. HARSHE: You would, of course, have to look at the specific location of the rooms you were talking about, because that will determine the HVAC system, for example. I was thinking primarily of design controls where we are talking of -- if you are talking about heat from one room going into another room, for example.

MR. LIPINSKI: Also, loss of ventilation affecting several rooms simultaneously.

MR. HARSHE: Oh, yes.

MR. LIPINSKI: You may not pick that up on a walk-through unless you realize where the ventilation is coming from for those individual rooms. You may have to go to your system diagrams.

MR. HARSHE: The design reliance I was speaking of is under the functional which is separate from the spatial, which is covered by the walkdown. So you look and see if something was overlooked in the design process. You can think of the spatial as being a verification that the design process was correct on functional.

MR. LIPINSKI: Okay.

MR. OKRENT: Let's go on to the next agenda item, integrated control systems.

MR. HAMM: Good evening, my name is Bob Hamm with Consumers Power Company. I would like to talk to you a little bit this evening about the functions interfaces and the improvements that we have made in the integrated control system.

The integrated control system is a B&W design concept which has been utilized for control of both nuclear and fossile power plants. It is a feed forward control system which simultaneously coordinates the response of the reactor's steam generators and turbines.

If I could have the first slide, please.

(Slide.)

This is a block diagram which shows essentially major functions performed by the integrated control system. The top block is designated the unit load demand. This is for the operator's major interface with the integrated control system. It is here that he dials into or inputs into the system the number of megawatts he wants the turbine to generate.

Also coming into the unit load demand is what we call the evaporator steam demand system, which is shown coming into the top block there. This is the major difference between the integrated control system for Midland and the integrated control system for the other B&W plants, in that the other B&W plants do not have a process steam or a steam supply system.

The evaporater steam demand measures the steam flows, pressures and temperatures of the steam going to the process steam evaporaters, determines the total energy content which is being sent to the evaporaters, and then conditions this to give the equivalent megawatts electric generated, and then feeds it back into the unit load demand.

The unit load demand is then added to the load demand going to the turbine generators so that we can send to the reactor the total load; not only the turbine load, but also the load going to the process steam. The unit load, in addition to allowing the operator to input the unit load that he is looking for, also limits the rate at which this load demand change is forwarded to the rest of the control system.

In the next block --

MR. MATHIS: I have a question on that. In your utility operation of this plant, do you intend to use it mainly as a base load unit?

MR. HAMM: We would be mainly a base load unit.

MR. LIPINSKI: What percentage turbine bypass do you have?

MR. HAMM: Turbine bypass?

MR. LIPINSKI: In terms of turbine bypass.

MR. HAMM: We have 15 percent that bypasses to the condenser, and an additional 7 percent that dumps to atmosphere for a total of 22 percent.

If I can continue here, the integrated control block there takes the demand from the unit load demand. It conditions it prior to sending it on to each of the individual control systems farther downstream. Basically, it takes the unit load demand which comes in in megawatt electric and converts it to feedwater flow demand for the steam generator system. It stays a megawatt demand for the turbine control and to a neutron power demand for the reactor control.

The integrated control system then sends forward each of these systems to the appropriate control systems. As we already discussed, we have a turbine bypass control. This is used to control pressure during startup of shutdown and upset conditions.

The turbine control is a pressure controller where the pressure setpoint is modified by the megawatt demand. The steam generator control is a feedwater controller, and the reactor control controls the reactor rods to control neutron power.

(Slide.)

I put this slide up just to show you when we talk about the integrated control system, it requires many other systems for it to operate correctly and to supply information to the control system. So I have just outlined here the major systems that require inputs to the integrated control system. The most important one is shown there at the top; that is the non-nuclear instrumentation system. The majority of inputs to the integrated control systems are provided from the non-nuclear instrumentation.

In addition to providing inputs to the integrated control system, the non-nuclear integration provides annunciation indication and recording of important parameters in the control room and the control of some parameters as provided by the non-nuclear instrumentation including the pressurizer spray, the non-nuclear heaters and the pressurizer level control valves.

Also inputting into the integrated control system is the evaporator steam demand system, as I showed earlier. The reactor protection system which inputs the neutron power level, the control rod drive control system which inputs upset conditions, asymmetric rod conditions of this type to cause the integrated control system to run the reactor back. Also, the turbine supervisory instrumentation inputs, the megawatt-- the generated megawatts to the control system.

The outputs from the ICS go to the control room to annunciate off normal conditions, and the integrated control system has control of the feedwater valves and pumps, the steam dump and bypass valves and the turbine control valves, and also control of the control rod drives, the control rods.

MR. LIPINSKI: It has nothing to do with the PORV.

MR. HAMM: The PORV has been removed from --in the original design, the PORV was controlled from the non-nuclear instrumentation system, not the integrated control system, but we have upgraded the PORV to safety grade and we have removed the control of that valve from the non-nuclear instrumentation.

MR. LIPINSKI: Okay.

MR. HAMM: In mid-1979, B&W performed a failure modes and effects analysis of the integrated control system in response to a request by the Commission after the incident at Three Mile Island. Upon receiving that report, Consumers began evaluating the integrated control system to see if there was anything we could do to upgrade that particular system at that point in time. We also had access to information on the event that occurred at Rancho Seco i February or March of 1978, so we factored that into our evaluation, too, to see if these improvements could -- any potential improvements could mitigate or prevent the consequences that occurred at that particular time.

About the time that we were completing our evaluation in February of 1980, there was an event at Crystal River where they had a loss of non-nuclear instrumentation. We had pretty much completed the modification or determined the modifications that we wanted to make to the Midland ICS based upon the failure modes and effects analysis and the Rancho Seco incident, but we went back and looked at the Crystal River incident to be sure we had covered all bases there, also.

We determined that there were no additional modifications which we felt needed to be made based upon what our evaluation of the Crystal River incident was. So the modification we had at that time we pretty much stuck with.

Now, at the time we performed the evaluation, there were already some existing differences in design between the Midland integrated control system and the integrated control systems at the operating B&W plants. The auxiliary feedwater system at Midland was a safety grade system, and control of that system was independent of the integrated control system.

The second major difference was we had indication in the control room which was independent of the NNI/ICS. These indicators are indicators that the operator can turn to in the event that he should lose the information that is coming particularly from the non-nuclear instrumentation. But based on that review, we did make several modifications to our system.

The major improvement was that we improved the power -- the external power supply reliability to both the non-nuclear instrumentation and the integrated control system. We provided redundant battery power to both the integrated control system and the non-nuclear instrumentation.

We also went into the integrated control system and the non-nuclear instrumentation and reduced the sizes of all the fuses that were located within the system to minimize the probability that local faults would result in complete loss of power to the system. Also in evaluating the system, we determined that there were some failure modes within the non-nuclear instrumentation which could put the plant in a non-conservative direction, and these were that in a loss of power to the non-nuclear instrumentation, the spray valve would fail open, the pressurizer heaters would fail on. So we have modified the system to incorporate a feature to ensure that the spray valve will not fail open and the pressurizer heater will not fail on, in a loss of power to the NNI/ICS.

One other thing that we have incorporated into the design is to alert the operator to the fact that we have lost power to any of these systems. We feel we have greatly increased the reliability of the system and decreased the probability that power will be lost to these systems. But in the event power is lost, we have provided annunciator alarms in the control room to alert the operator to the fact that these systems have lost control power.

We are providing in our emergency procedures actions to be taken by the operator, including which indication he should rely on, in the event that the non-nuclear instrumentation or integrated control system loses power.

MR. OKRENT: These modifications you have just been discussing, did they arise out of Midland's own study, or are these things that B&W suggested to you, or were they a result of a joint venture? Just how did they come about?

MR. HAMM: As I said, we received the failure modes and effects analysis. Within them, B&W made some recommendations, but their recommendations were basically that the largest contributors to fault in the ICS was the external power supply arrangement, over which they had no control. So they asked each plant to review their own individual plant, the power supply to the integrated control system, which we did. So this was Consumer Power's evaluation based somewhat on the B&W recommendation to look at these particular things.

I can't characterize -- if I look at the modifications I ended up making, I can't say one of them was a direct B&W input that they said specifically to make this fix, and the others were things that Consumers did on their own.

MR. OKRENT: Are there changes to the ICS itself or are they primarily to the -- either exclusively to the power supply or exclusive knowledge that the power supply has failed?

MR. HAMM: Well, the second one is a change to the ICS itself. An internal change. We reduced it a few sizes within the ICS. The third one is a change to the non-nuclear instrumentation in itself, in that we found these failure modes within the non-nuclear instrumentation, so that is within the non-nuclear instrumentation itself.

The first and the last one are, as you stated, to improve the reliability of the external power supply and to improve the operator's state of knowledge.

MR. LIPINSKI: The integrated control system still relies on the reactor protection system for the nuclear measurements. That is shared information. On your diagram, you show the RPS is an input to the IPS.

MR. HAMM: That is correct. The nuclear system signal from the reactor protection system is input to the integrated control system. The way that it is put in, the two opposite -- there are four power range detectors. We are talking of power range detectors when we are talking of input to the integrated control system. Therefore, detectors.

There are a total of four power range detectors. The two opposite each other are added together. The average is taken and the opposed are taken together, the average is taken and they are then put together to select the highest input. That is what is supplied to the integrated control system.

MR. LIPINSKI: And these are buffered signals?

MR. HAMM: Yes, these are buffered signals, according to IEEE 279.

MR. LIPINSKI: You can also take a full turbine trip and ride it out without shutting the plant down through the integrated control system?

MR. HAMM: Well, it has yet to be proven in practice, but it is our intent that we will tune the integrated control system such that we can take a turbine trip and run the reactor back to 15 percent power on the bypass through the condensors. That is our design goal.

MR. OKRENT: You have now, if I recall correctly, a safety grade, high level trip of feedwater for the steam generators.

MR. HAMM: That is correct.

MR. OKRENT: When did that come about?

MR. HAMM: When did that particular evolution come about?

MR. OKRENT: Yes.

MR. HAMM: It is within the last two years that we went in and upgraded -- not upgraded -- we put in this high level protection. The safety grade overfill protection to the steam generators.

MR. OKRENT: Is that at the initiative of the staff?

MR. HAMM: It was about the same time -- no, it was not at the impetus of the staff. It was about the same time we were performing this particular review. There were things I guess we could have taken credit for that we changed based on the integrated control system, but I didn't make the decisions to make the changes. They had already been made.

So one of the things that B&W reports looked at, there were basically three major things that could go wrong with the integrated control system that can affect you. One is you end up over-feeding the steam generators. The second is you under-feed the steam generators, and the third is you depressurize the steam generators.

Now we have safety systems that back all of those up. So that for the overfeed, we have the overfill protection, for the underfeed we have safety grade auxiliary feedwater independent of the ICS, and we have main steam isolation for the depressurization of that. So it was at about the same timeframe because when I was looking at those particular events, I was making sure we had a safety system to back them all up. At the same time, we were also taking about putting in the overfill protection.

MR. OKRENT: What was the cost, roughly, of, for example, the safety grade high level trip on feedwater flow?

MR. HAMM: I am afraid I can't answer that one directly. I can look and see if there is anyone who can.

MR. OKRENT: I am interested. Does anyone know approximately?

MR. BALLWEG: Tom Ballweg with Bechtel. I would guess that the cost would be somewhere on the range of a quarter to a half of a million dollars per unit total installed cost.

MR. OKRENT: Where does that go, primarily? Is it for hardware per se or installation per se? I must confess it is more than I was going to guess.

MR. BALLWEG: The direct hardware cost of the parts cost is a small percentage of the total cost. A lot of the cost goes into evaluating the effects, a lot of it into modifying related systems that interface with it.

It is not apparent when you first get into these things how they interact with other systems, so there is a tremendous amount of other systems type interactions, and the biggest cost is really in the construction labor.

MR. OKRENT: Okay.

MR. HAMM: Could I have the next slide, please?

(Slide.)

In addition to the evaluation that we have just discussed, we are presently performing some additional evaluations of the control systems which include the integrated control system, the evaporator steam demand development system and the non-nuclear instrumentation system. We are looking at additional failures that were beyond the scope of the original failure modes and effects analysis. We are backing up all the way to the sensors, so that the effects should include -- the scope of the original failure modes and effects analysis just drew a circle around the integrated control system, so we are backing it up an additional step to look at the failures of sensors and other systems that those particular systems go through.

So we are looking at the effects of other control systems which may share a sensor with the

NNI/ICS. In other words, a failure may cause the ICS to do something, but it may also go to another control system to cause that controls system failure. So it is somewhere in the systems interaction type of evaluation that we are doing.

We are looking at the loss of single sensor inputs, we are looking at the loss of break in instrument lines having more than one instrument, with at least one input into the above systems. We are also looking at failure of individual fuses or breakers in many of the systems we are evaluating. We are also evaluating performing a more detailed evaluation of complete loss of power to any of these systems.

This evaluation is ongoing. It is in the final stages and is undergoing final review, inhouse review, within B&W at the present time. It is my understanding that we do not expect -- that this evaluation is not determining any failures that would result in an unsafe condition.

MR. LIPINSKI: If you wanted to carry that one step further, if you have a piece of equipment that is out of service and you are repairing it and you have some window that allows you to do this repair, will you then assume that you have a single failure somewhere else in the system? Effectively, that is a double failure, saying you have one failure. That piece is out, you are repairing it. Then while this is going on, another failure occurs.

MR. HAMM: I am afraid I -- I may be missing your point, but I don't see how that relates.

MR. LIPINSKI: You say loss of single sensor input. You may have one sensor out and you may be fixing it. Then another sensor may go on you. Effectively --

MR. HAMM: We are assuming the sensor we lose-- and in many cases from the NNI we do have redundant sensors and we can select from the control room which sensor goes into the control room, so we do have redundant sensors in some cases. One of them could be out. We are assuming when we lose a single sensor, we are saying that that is the sensor that supplies the input to the integrated control system.

MR. LIPINSKI: That is what I am saying. Namely, you have multiple inputs going in here. If we took your list I could pick one for you and say you are servicing that one. Oh, I see. You are saying if you are servicing that one, you select an ultimate sensor to replace it while you are doing service.

MR. HAMM: Yes.

MR. LIPINSKI: So the function is restored.

MR. HAMM: Yes.

MR. EPLER: The principal consequence of Crystal River and Rancho Seco failures I believe were cold overpressurization, which is now an important issue. I would believe that your improvement in regard to overfill of steam generator would relate to that. And would you say that what you have done to the ICS would minimize cold overpressurization events?

MR. HAMM: I would say that the things that we had already incorporated into our design, beyond the improvements that we made recently, minimized that event. One, our auxiliary feedwater system is independent of the integrated control system, and is safety grade. So a loss of power to the integrated control system would not result in some of the feedwater events that occurred at both Rancho Seco and Crystal River.

Another thing we have is we have indications in the control room that are independent of the integrated control system. One of the reasons they got into trouble both at Rancho Seco and Crystal River was because they were blind when they lost the non-nuclear instrumentation at both of those plants. So we think -- and with our overfill protection, that is just an additional assurance beyond the safety grade AFW system that we would not overpressurize or overcool the plant.

MR. LIPINSKI: On the Crystal River event if I recall, the ICS sent the signal out to cut back the auxiliary feedwater directly from the control room. It also sent a signal out to run out the control rods as a direct signal from the ICS.

Now, the third one I thought came directly from the ICS. That was to open up the PORV with a direct signal. Am I correct in those three statements?

MR. HAMM: Yes. The PORV at Crystal River was controlled by not the integated control system, but the non-nuclear instrumentation. That is where the power was lost at Crystal River, in the non-nuclear instrumentation.

MR. LIPINSKI: That is because it shared that information, that it looked like it was all a common event.

MR. HAMM: Yes.

MR. TEDESCO: That was part of the reason why we wanted the ICS to be independent of the auxiliary feedwater system.

MR. LIPINSKI: Right.

MR. HAMM: Also, our PORV is independent of the non-nuclear instrumentation that is also upgraded to safety grade.

MR. LIPINSKI: Okay, so the systems that appeared at Crystal River are not common to your system based on your common design?

MR. HAMM: Yes, that is correct. That is all I had in the way of a presentation. If there are anymore questions.

MR. OKRENT: In the things that you have done with regard to helping the operator know what is going on in case he should lose the power to his non-nuclear instrumentation. Does that include a change in the failure mode of the instruments? In other words, they fail off-scale, or normal or however you want to put it? I know you said that there is a signal that you have lost power, but I suspect he may have suspected that anyway. If I correctly, what what you said is he could go to the procedures and look up and he would find out which instruments to trust.

MR. HAMM: Yes, we are going to have procedures for the event of a loss of integrated control.

MR. OKRENT: But will those that fail fail clearly in a way that they don't look like they are normal?

MR. HAMM: The integrated control system in the non-nuclear instrumentation system are -10 to +10 volt control systems, and the system will fail midscale. That was the major thrust for putting on the alarm to indicate the loss of control power. But there are other things that we think will help the operator to recognize the fact that he has a failure.

There is extensive training on the failure of single inputs to the integrated control system that is performed on the simulator. The present simulator is at B&W and will be performed on the plant-specific simulator when it is delivered. Both classroom training and actual failing of these instruments out on the simulator will show the operator what happens on the loss of a single input to the integrated control system.

MR. OKRENT: Why is it retained that they fail midscale? Is it something that is a desirable feature? Or is it something that is very difficult to change? I'm trying to remember.

Did NSAC in its review of Crystal River suggest that things not fail midscale? Was that one of the recommendations in the NSAC report on Crystal River? Am I wrong?

MR. HAMM: I don't recall the exact recommendation. I know the failure has been discussed repeatedly with regard to the integrated control system and non-nuclear control system. The reason for not changing it out, as I said, it is a -10 to a +10 volt control system by design. The integrated control system could be designed so that you could make it a zero to 10 volt or a 4 to 20 milliamp control system. Then you would have failures low or failures high.

But the reason that it would be very difficult to do, it would be tearing out the existing control system, the large number of cabinets we have, and going to a vendor other than the vendor who has supplied the existing system and buying a complete new control system.

MR. LIPINSKI: I think in their particular case it is timing. Your equipment is already ordered and designed according to that specification.

MR. HAMM: It's also installed.

MR. LIPINSKI: When you start on the drawing board all over again, you could design it to be a zero volt such that the meters would fail to zero. But in terms of their position, they placed this order years ago and they're committed to this particular system.

MR. OKRENT: And you are saying that except for large-scale surgery it's impossible to remedy?

MR. HAMM: It would take large-scale surgery to completely alleviate the problem. That is why some of our fixes were putting the alarm in the control room, why we are stressing training, and why we are stressing -- or why we are having procedures to tell the operator what to do.

MR. OKRENT: Let me see. I'm just trying to think aloud. You have indicated that there would be some kind of an alarm to tell the operator that he has lost power to the non-nuclear instrumentation or to the integrated control system or both?

MR. HAMM: That's correct.

MR. OKRENT: Is that a safety-grade alarm?

MR. HAMM: No, it's not.

MR. OKRENT: Not nice.

(Laughter.)

MR. HAMM: Well, the operators nowadays are well attuned to the fact that the system fails midscale. They say, we are stressing the midscale failure in training and to get the operator to question when he sees that indicator sitting midscale, that he should question it and check around for some other instrumentation.

MR. MOELLER: Are the instruments in general arranged to read under normal operations somewhere near midscale? I thought I heard one time that was good human factors design.

MR. HAMM: Well, good human factors design would be probably within 50 to 75 percent of the scale reading. I generally believe that the indicators usually indicate a little above the midscale point. More on the 75 percent range would be an ideal design.

MR. MOELLER: Roughly how much money -- I'm not advocating it. How much money would it cost to change?

MR. HAMM: You heard the quarter to a half million dollars per plant just to change and have two valves go closed on high level in the steam generator. So we're talking about the entire control system. I hesitate to guess.

MR. MOELLER: It's substantial.

MR. HAMM: It would be substantial, yes.

MR. OKRENT: By the way, how many indications does one lose, approximately, with loss of non-nuclear instrumentation in the control room? Are we talking 200 roughly, do you recall?

MR. HAMM: About eight to ten.

MR. OKRENT: Eight to ten, that's all.

In principle, I would assume you could have some kind of a light that went on if this set of eight to ten lost their power.

MR. HAMM: As I said, through our annunciators--

MR. OKRENT: Is that an individual alarm on each annunciation?

MR. HAMM: It's a total alarm that measures the power in the cabinet. The problem that we have with this particular control system, the indicators require, in addition to a signal voltage of zero to ten volts, it also requires a voltage plus or minus 34 volts to fire the indicator.

What we are measuring is the loss of power to the indicator, which would make it go midscale. But there is no way we can really measure the signal going to zero volts, because zero volts could be the exact signal that it wants. So --

MR. OKRENT: Any other questions on the nuclear control system?

(No response.)

MR. OKRENT: Well, it looks like we are halfway through the agenda. Maybe before we begin the next item, we might take a ten-minute break and reconvene, say at ten after 6:00.

(Recess.)

MR. OKRENT: The meeting will reconvene.

I hope you will pardon the informality, but instead of smoking I eat apples.

I think Dr. Lipinski had a question remaining from the last subject.

MR. LIPINSKI: The last statement that was made was that the indicators had an individual separate 24-volt supply and they were designed to fail midscale, and there are 8 to 10 indicators that were stated as being associated with the non-nuclear indicators.

MR. LEWIS: Sir, our representative is not here yet.

MR. OKRENT: We'll come back to this if you like, and go on to the next topic and take this up at the end of the next topic: environmental and seismic qualification.

MR. ZABRITSKI: My name is Jim Zabritski. I'm the section head in the technical services section in the Midland design production department. The first slide, please.

And I would like to discuss the subjects of environmental and seismic qualification.

MR. OKRENT: In fact, I wasn't sure who worked it. It doesn't seem like magic.

(Slide.)

MR. ZABRITSKI: Second slide, please. There we go.

(Slide.)

Basically, this slide shows the participating organizations for the equipment qualification effort. Consumers Power Company is responsible for the overall management and technical direction of the program. We have been heavily involved since 1978 in responding to some of the early bulletins.

We first reviewed our equipment qualification status and submitted a 50.55(e) report because we felt we had some problems, and we have been pursuing those ever since. We have followed NRC and industry efforts. We are involved in the AIF and EPRI, and also the equipment qualification group to qualify transmitters.

Our equipment suppliers, B&W and Bechtel, have looked at the equipment and are each responsible for their own equipment. We are -- Bechtel has utilized the services of Wylie Laboratories as an environmental qualification consultant, and basically Wylie has helped Bechtel and us relative to developing a spray chemistry report, doing some work relative to radiation threshold, and is also heavily involved in evaluating equipment against the requirements.

Nutech is a consultant directly to Consumers and is involved in both seismic and environmental qualifications, and they have provided direct support to us in the performance of independent review and audit, review of licensing documents, and also in program management in both the environmental and the seismic programs.

The second slide, please.

(Slide.)

Okay. First of all, relative to environmental qualification, I would like to cover the elements. Our program is developed in accordance with current criteria. It meets NUREG-0588, category 2. It is also responsive to NUREG-0737, IEEE-323-74, Reg Guide 189 and 197.

We are a category 2 plant. We received our construction permit in December 1970. Our program addresses qualification of electrical and mechanical equipment. Relative to mechanical equipment, the program is in an infancy stage and basically we will be reviewing the non-metallics associated with equipment, especially for things like significant aging.

Our program also addresses harsh and mild environments. Let me qualify that relative to mild environments. Our program will meet the requirements of the new final proposed rule, which will allow us to utilize maintenance testing and surveillance for the mild environment.

Also, then the program accounts for resolution of discrepancies and deficiencies and contains correction action plans which allow for retesting shielding or moving or replacing equipment as necessary if it does not meet the requirements.

Again, the last point is our program is a 40-year program, and we acknowledge that EQ is a program that is a lifetime program and it is essentially a life of the plant program.

The next slide.

(Slide.)

Basically, relative to status, we made our submittal to the Staff on May 3rd, 1982. It consists of the methodology, which is for the overall program, the individual qualification data, component data, evaluation sheets for each component, and the environmental equipment qualification sheets for each program.

Again, it contains the corrective action plans which indicate all those actions necessary to qualify all remaining equipment. Presently, we also have some equipment test programs under way. These are specifically the active ones right now, are things like in-core thermocouples, fission chambers, pressurizer heaters, PORV and pressure transmitters.

We are in the process of final_ _g our test report evaluations and we recently completed an independent audit of the efforts that have been performed by Bechtel. Our surveillance and maintenance programs are being developed and we will on performing -- or verifying installed equipment for consistency with the EQ requirements. At this state, the NRC audit is scheduled for June of 1982.

That completes my presentation on environmental equipment qualifications and I would like to go to seismic qualifications next.

(Slide.)

MR. OKRENT: Are there any questions in this area?

(No response.)

MR. ZABRITSKI: Relative to seismic qualifications, again our program is developed to evaluate all safety-related equipment, including that required for cold shutdown. The program is based upon the design floor response spectra, which was revised in 1982, which occurred as a result of the various structural changes, the remedial soils activity codes and model changes.

Our program basically assures that all equipment is being requalified in accordance with the FSAR commitments. Basically, the commitment is laid out there: IEEE Standard 344 1971 for equipment purchased prior to 7-1-1975, and IEEE Standard 344 '75 for equipment purchased after July 1, 1975.

Relative to the licensing review, we are evaluating all of our equipment against the current NRC seismic SQRT requirements.

The next slide.

(Slide.)

Again, relative to the overall status on the seismic qualification, it is -- we have completed the revised floor response spectras. They were just recently completed, in early 1982. All requalification programs are under way. We have about 430 programs, I believe, total.

We have independent reviews in process. We have conducted some with Bechtel and B&W. And we presented our program to the Staff on March 17, 1982, and the Staff agreed with our basic approach and is still waiting for the final report and the audit prior to closing out the issue, however.

We do plan on providing our seismic report to the Staff in July and would hope to have our SQRT audit in September of '82.

MR. OKRENT: Could I ask the Staff why this item is an outstanding issue and not a confirmatory issue? For example, what is it about this item that the Staff could place it on the outstanding item list? The Applicant acts like everything is progressing from its presentation.

MS. ADENSAM: Eleanor Adensam of the NRC Staff.

Dr. Okrent, I would simply say that as far as the Staff is concerned, we have not come to complete closure on these issues, partly because we are lacking information from the Applicant we don't really consider it confirmatory at this point in time, so therefore we categorize them as open items.

MR. OKRENT: When something is confirmatory, you're lacking information. Otherwise it wouldn't be confirmatory any more, because you would have the information.

MS. ADENSAM: In some cases, the information we're lacking is documentation information. In this case we have not seen the Applicant's submittals.

MR. OKRENT: Is there any reason to anticipate any difficulties in any specific aspects of it?

MS. ADENSAM: I can't speak to specifics. But as you well know, both environmental and seismic equipment qualification have been a rather touchy or difficult issue, let me put it that way, for some time. And since we have not yet seen the Applicant's submittal in certain areas, I could not say. I couldn't speak to the specifics, but that is possible.

MR. OKRENT: How much of the equipment is unique to Midland that has not been used on a plant already in operation or closer to operation than Midland?

MR. ZABRITSKI: That's a difficult question to answer.

MR. OKRENT: Is it much, very little?

MR. ZABRITSKI: Just to give you an idea of how much equipment we have relative to Class 1E equipment, equipment that must be qualified, it is about 6,000 pieces. For the harsh environmental equipment qualification, we're talking about probably 1200 pieces of equipment.

Now, we have like 50 -- approximately 48 programs for harsh environment and 430 different seismic programs. So there is a tremendous amount of equipment, some of which has been used, and perhaps a few items that have not been used, like the in-core thermocouple qualification program and pressurizer heaters. We've been the first one to qualify pressurizer heaters.

However, may I call it to your attention that those constitute closed, accepted programs in the Staff's eyes when the Applicant commits to qualifying in accordance with current criteria.

MR. MOELLER: When you say 430 programs, would you clarify that for me?

MR. ZABRITSKI: Seismic reports. In other words, equipment types that are represented by one seismic report. Yet those 430 programs represent 6,000 pieces of equipment.

MR. OKRENT: With regard to the seismic qualification, let me pose for purposes of discussion a certain scenario and understand then from your comments how seismic qualification would give the answer for the operator or would propose to give the answer, and so forth.

There is some revised seismic design basis now that you and the Staff have agreed to. Let me postulate that there is interest in knowing that there is substantial margins for everything needed for safe shutdown heat removal and anything that could complicate safe shutdown heat removal, and there is substantial margin for earthquakes having a lesser probability but a higher amount of shaking.

Would that information be available from the qualification program as it stands? Would it be available from other qualification programs? Obviously, I'm not talking now about the containment building per se. That would come from an analysis.

MR. ZABRITSKI: Again, our program is based upon the design spectra. That design usually is inputted, or it might be inputted, into an analysis, like for example a cabinet. The analysis might be used to determine a given response spectra at each instrument location, and then the instruments might be qualified to -- they may have generic qualifications.

But the specific response spectra would determine whether or not the generic qualification is adequate.

Let me make another statement, too. The spectra that I am referring to, this revised floor response spectra in 1982, is based upon the .12g. It is not the site specific response spectra.

Now, there is a program -- I'm in the design production department, because we have 6,000 pieces of equipment, -- to make sure that are done in accordance with the design basis There is another program, the margin review program, which is going to look at pieces of equipment relative to the site specific response spectra.

MR. OKRENT: Well, what fraction of the testing with regard to seismic qualifications has already been done, would you say?

MR. ZABRITSKI: The testing, those 430 reports are already completed.

MR. OKRENT: So it's a question of --

MR. ZABRITSKI: It's a question of going back and reviewing those reports against the revised response spectra.

(Pause.)

MR. OKRENT: Well, there may be somewhat of a question that will at least be worth thinking about. As you can recall from the discussion at the last Subcommittee meeting, there is a considerable spectrum of opinion concerning the likelihood of low probability earthquakes of a certain size. And while it is not a straightforward issue, the NRC is going to have to think perhaps again on this matter.

For things that you can handle by analysis, one has a tool. But for things that are done only experimentally, if they were tested just to the point of the requirement before, there could be some other complexities.

Well, I will just note this point. Are there other questions on the subject?

MR. LIPINSKI: How do you qualify your Class 1E equipment, such as relays, breakers, solenoid valves? By analysis? By test?

MR. ZABRITSKI: The devices you are talking about relative to the harsh -- are you talking seismic or environmental?

MR. LIPINSKI: Seismic. I should have been specific.

MR. ZABRITSKI: Well, for the most part I believe relays and electrical devices are performed by tests.

MR. LIPINSKI: Okay. Because in yesterday's meeting there was somewhere a missing link in the fact that all of the simple devices that are represented by spring masses have a resonance frequency and a relay does not have any damping and very little friction;

therefore, it takes very little excitation in terms of the g forces to cause the device to go through full swings.

In the review yesterday they could not state specifically what the resonance frequencies were for these individual devices, as to whether they were beyond the excitation frequencies. And the building response does not give you that answer, because that goes through the damping factors based on the ground-to-building. And if the frequencies are present in the seismic event, you can expect these devices to slam back and forth.

Are you doing an analysis of each one of the devices in terms of their mass spring constants to see what their individual resonant frequencies are?

MR. ZABRITSKI: No. One case I am familiar with -- well, a specific case on the NIRPS equipment, the analysis is utilized on the cabinet, and then each module is seismically tested. That goes back to the early seventies. It was even performed that way for the B&W equipment.

MR. LIPINSKI: And those cabinets only went out to the floor response spectra and then they cut off, on the assumption that there are no frequencies higher than that. But for simple devices it takes very little excitation, providing the excitation is there at the resonant frequency.

If I knew the resonant frequency was out at a couple of kilocycles, I wouldn't be concerned. But if it's out at 75 cycles and you ran your tests at 50 cycles, then you really have not done a complete evaluation.

MR. OKRENT: Maybe the Staff has a comment.

MR. JACOBS: Peter Jacobs from Consumers Power.

A lot of this limitation to the 33 hertz was as a result of the requirement in 344-1975, and that is why a lot of the testing was done that way. But if you will look at a lot of the tables, even though they only excited them up to 33 hertz, the tables themselves vibrated at other frequencies.

So I think you covered a lot of the higher frequencies in that manner. The limitation was that we tested to the frequencies required in the IEEE standards.

MR. LIPINSKI: The fundamental question is: What is the basic resonant frequency of the device, irrespective of how you tested it? That is a simple analysis to know what the mass is and the spring constants to say this is resonant at X cycles per second. It is either well above the test frequencies and therefore you wouldn't expect it to be excited unless the test frequency was present correspondent to the resonant frequencies of the device.

Somehow it is so simple, it amazes me that the question cannot be answered in that manner.

MR. JACOBS: I guess the problem is that when you get down to actually doing the calculations for some of the smaller complex devices it is not as easy as that.

MR. LIPINSKI: I agree with you where you're talking about arrangements of contacts that may pull apart, if they're not screwed in, in shaking. But I'm talking about the simple devices that have resonant frequencies.

If I hit them along the right axis, I can get relays to slam in and out, I can get breakers to slam in and out, if I'm exciting them along the right axis and they have the resonant frequency. It's only those components I'm raising the question about. The rest of this stuff, I agree, you would have to excite it to find out whether it would hold together.

But the simple devices that are mechanically resonant, if you hit them along the right axis they will slam back and forth.

MR. OKRENT: Well, that is a question I guess we should not lose, and you might want to call it to the attention of Mr. Ray, if you haven't already.

MR. LIPINSKI: He was present at yesterday's meeting.

Unfortunately, when they came out with the rulemaking for qualification it was only for environment and they said seismic would be settled for a later date. So it had not come up at a Subcommittee meeting. but it did come up at yesterday's meeting on CRBR.

MR. HAMM: Which meeting, again, was that?

MR. LIPINSKI: The Clinch River Breeder Reactor. They discussed their qualification for seismic.

MR. OKRENT: Can I ask a related question? When you do a test, is it always just to see whether it meets the design motion, or are they tested beyond that to see what the failure point is?

MR. ZABRITSKI: That would depend upon the specific equipment. Some equipment I mentioned is generically qualified, such as valves. Some of the B&W-supplied was qualified.

The equipment for Midland, I believe -- and let me confirm this -- it was tested to the response spectra, the given floor response spectra. That was the input to the machine.

MR. OKRENT: So you wouldn't want to test that to failure, because that was what you planned to use?

MR. JACOBS: On this failure testing, since the seismic test is part of a sequential test, you leave that piece of equipment for like the LOCA test or something like that. So very few fragility tests are run.

MR. OKRENT: I assumed so. I just wanted to check.

Anything else on the subject?

(No response.)

MR. OKRENT: All right. Let us go on.

(Slide.)

MR. GIBSON: My name is Lewis Gibson. I am the section head for the Safety and Analysis Section for the Midland project for Consumers. The topic I would like to talk to you about is the decay heat removal system operations.

By way of introduction, the ability to remove decay heat following a reactor trip or shutdown necessitates the capability to perform certain functions. They are reactivity control, inventory control, pressure control, and temperature control or heat rejection.

What we would like to talk about is the last point -- the heat rejection or temperature control. Our original design was -- our design criteria was to achieve and maintain hot standby conditions using only safety grade equipment. Our present design now incorporates the additional capability to achieve cold shutdown using only safety grade equipment.

First slide, please.

(Slide.)

In order to look at the systems that come into play for heat rejection or decay heat removal, this slide depicts the various ways that that function is achieved. As we go down the items on the lefthand side of the slide, we start with the steam generator -- its range of operation for heat rejection, that is, from the hot condition down to normally 280 degrees. We also show the automatic actuation on this valve for isolation at 585 pounds, as it turns out, saturated conditions.

The second heat rejection means is auxiliary feedwater, which we discussed previously with you. As a means of heat rejection we have the main steam relief valves. They are set at 1,050 pounds, a single point. Also, we have the power-operated atmospheric vent valves. They operates manually anywhere from 532 degrees, primary coolant system temperature, down to 280 degrees.

The next decay heat removal system that we have is the one known as the DHR system. It operates normally from 280 degrees down to ambient, although it may be operated from 325 degrees down to ambient under certain emergency conditions.

Finally, we have the backup means, if it would be needed. That would be the capability to feed and bleed for decay heat removal. That range of operation would again be from the hot condition down to approximately 325 degrees if needed.

Next slide.

MR. LIPINSKI: Hold it. These give the temperatures but they do not give the pressures. What are the corresponding pressures that you can operate at?

MR. GIBSON: The steam generator system and the auxiliary feedwater system operate on the full system pressure, okay? Again, you are talking about the steam generator system pressure, which starts at 900 pounds and works its way down and operates in the saturated mode for the secondary side for decay heat removal so the pressure would correspond to the saturation temperature for the temperature that you are at.

For the decay heat removal system, which cuts in at 280 degrees, normally it would function from, I believe, somewhere around 500 pounds -- 550. Correct me if I am wrong. About 350 pound, 550 is the innerlock. 350 pounds primary system pressure for decay heat removal.

For feed and bleed, that system, that method of operation could operate from normal primary system pressure on down if needed.

MR. LIPINSKI: Your HPSI pumps can operate at full reactor pressure?

MR. GIBSON: That is true.

MR. LIPINSKI: At the capacity you need?

MR. GIBSON: That is true.

The next slide, please.

(Slide.)

This is a simplified drawing of the auxiliary feedwater -- steam generator heat rejection system. This simply shows that we inject auxiliary feedwater to the OTSG. We remove heat from any one of a number of devices and I will -- I will start from right and go left so we get order of precedence here.

Normally we would use a condensor dump as a means of heat removal for this heat rejection mode. The next device that we have available is the modulating atmospheric dump valve, shown next in line. Then we have the main steam isolation valve and upstream of that we have the power-operated atmospheric vent valve and the code safeties. So this shows the decay heat removal path for the once-through steam generator.

The next slide, please.

(Slide.)

This slide shows the decay heat removal system, again a simplified drawing of it. The decay heat removal pump draws a suction from the hot leg to the primary coolant system through a single drop line that has redundant isolation valves in it. Again, I show one of two trains from that point out. There are actually two decay heat removal pumps, any one of which can perform the design function.

It pumps through a decay heat removal heat exchanger and then is returned back to the primary coolant system. This provides the decay heat removal path normally, as I said, from 280 degrees down to ambient.

In the interest of the schedule, that is all I had prepared as far as presentational. Are there any questions?

MR. LIPINSKI: The condition for this system is that the system pressure be brought down to 350 psi before you can open the valves.

MR. GIBSON: That is true.

MR. LIPINSKI: So you either have to have your steam generator functional to bring your pressure down or go through a feed and bleed mode in order to get the system pressure down.

MR. GIBSON: You would have to have a means of bringing the pressure down to that point before you could put it into operation, yes.

MR. LIPINSKI: Now what kind of capacity do you need in GPM for feed and bleed, assuming you do not have the steam generators available?

MR. GIBSON: We have done an analysis for the feed and bleed mode. Looking at that analysis, the capacity of one high pressure injection pump at the -- for instance, the PORV set point would be adequate to remove the decay heat generated in the primary coolant system.

MR. LIPINSKI: How long would that process have to continue before you could finally get to the regular system here?

MR. GIBSON: We have not analyzed the time since this is what I would consider not a normal routine or a normal function that we have designed for, but really just a capability.

Frankly, if we were in a high pressure feed and bleed operation we would probably choose to hold the primary coolant system at temperature until we had another means of achieving that. That is as far as we have taken that particular analysis. I can show you the analysis, if you need to look at it, that demonstrates what we can do as far as removing the decay heat but not -- we have not done an analysis to run through a cooldown with high pressure feed and bleed.

There are some obvious problems having to do with how much of the system you are going to cool down under that means, including the large masses of the steam generator that you are going to have to drag along with you.

MR. OKRENT: Epler?

MR. EPLER: The valves appear to be critical components. Can you tell me how they are powered?

MR. GIBSON: The motor-operated valves -- and there are in fact four of them -- two valves in series on two parallel trains. They are 1E-powered. Each set of valves is powered from a separate A and B bus.

MR. EPLER: Full phase AC?

MR. GIBSON: They are poly-phased?

I would have to find out if they are three-phased or not. Yes, they are three-phased.

MR. EPLER: Thank you.

MR. OKRENT: Any other questions? I guess that is it. I think we had a question left over from an earlier topic. Dr. Lipinski is going to raise that now.

MR. LIPINSKI: This goes back to the issue just before the break where we were talking about the meters that fail mid-scale. It was pointed out there were only eight to ten meters and that they had their own individual 24-volt supplies. That caused these meters to fail full-scale.

So it appears that replacing ten meters and the supplies that go with them give you the ability to go to a device that would fail to zero and I do not think that falls in the $250,000 to $500,000 category.

MR. ZABRITSKI: I think you are somewhat mistaken in the way the system works. There are plus or minus 24-volt power supplies within the NNI cabinets, the X and Y and Y cabinets. Failure of either of those particular busses -- there is only one bus. Each instrument does not have its own power supply, plus or minus 24-volt power supply.

MR. LIPINSKI: I was going by what you stated just before the break.

MR. ZABRITSKI: I may have implied that they were multiple because within the NNI-Y there are two channels. There are two separate transmitters and we have a select that we can select which one goes in, so there is a NNI-X channel and an NNI-Y channel. Each would have a 24-volt bus power supply.

But loss of that single bus results in a loss of the indication or the capability to monitor that parameter because that is also the voltage sent to the transmitter.

In addition, the signal voltage itself is minus 10 to plus 10 volts. Zero is minus 10 volts and full-scale is plus 10 volts.

MR. LIPINSKI: I thought you said it was zero to 10 volts for the signal and the signal went to an indicator that was based on a zero to 24-volt signal.

MR. ZABRITSKI: To the indicator itself, the signal is minus 10 to plus 10 volts. The details escape me as to why we need it. We also have a power supply coming to the indicator and that is where I think you have to develop a reference voltage within the indicator itself and use the plus or minus 10 volts off the power supply, plus or minus 20 volts into the indicator to provide a reference signal that we use to compare the signal again to generate the final output signal.

MR. LIPINSKI: I was assuming it was.

MR. OKRENT: Okay, thank you. Let us go on to the next topic.

(Slide.)

MR. SLAGER: I am Harvey Slager with Consumers Power Company. I would like to speak about our experiences with bolting. May I have the first slide?

(Slide.)

This first slide represents a summary of some of our experiences at the Midland site in somewhat chronological order. The first experience which we have had was the case of three reactor vessel anchor bolts which failed. I would like to defer that for a couple of minutes and go through some of the other experiences and then return to that one in more detail.

The second experience we had was the case of some pipe whip restraint bolts which we were in the process of testing to demonstrate the relationship between torque and preload and these bolts failed in a ductile manner during this test. Subsequently, we found that the material was soft. In one case the material had been extremely over-tempered and in another case the wrong alloy had been used. Instead of 4000 series carbon steel was used. The resolution of that was to replace both of the materials.

As a direct result of our experience with the reactor vessel anchor bolts, we started a search for other similar situations which might lead to failures. One of the most obvious examples was the steam generator anchor bolts which ended up being the same diameter and seemed to be generally the same material. In order to characterize these materials we harness tested them.

We found that the specified hardness limits in some cases the bolts accepted a hardness over the specified limits and in other cases below.

Again, in searching for areas of possible impact of the reactor anchor bolt failures we also conducted, prior to preloading, we conducted hardness tests on reactor coolant pump snubber anchor bolts. Again, we found, when compared to specified hardness limits, some of the anchor bolts had hardnesses to tight.

MR. OKRENT: What fraction of the bolts were appreciably too hard, would you say? One percent, ten percent?

MR. SLAGER: It was appreciable. My numbers here show for hardness test points with no averaging of the data points, out of 384 bolts, 116 of them exhibited hardnesses below specified limits and 50 exhibited hardness above specified limits. So those would be about 12 to 15 percent for too hard and 25 to 30 percent for too soft.

MR. OKRENT: These were supposedly sampled as part of an ASTM procedure before --

MR. SLAGER: That is correct.

MR. OKRENT: Did you draw any conclusions as to why you found this large deviation from limits in view of the fact that they had been sampled?

MR. SLAGER: Nothing conclusive, but there is the extent of sampling for some of the ASTM specifications is very limited compared to the material being supplied.

MR. OKRENT: Have you gone back to look at all ASTM bolt specifications to decide for yourself which of them you do not feel are adequate?

MR. SLAGER: We have looked at different specifications and there are some which appear to be superior in sampling to others. At the moment, with most of our bolting installed, our concern is not so much with the adequacy of the specifications but with the adequacy of the installed bolts.

MR. OKRENT: My question was in the same context. In other words, maybe you have picked up all of the suspicious kinds of bolts by what you have been doing, or maybe you looked at all bolts. I don't know.

MR. SLAGER: Let me continue with one more dot on here, which is our experiences are that we have a limited number of failures. We have a number of situations with boltings that do not meet the hardness limits specified.

As a result of that experience, we decided that we had to take a much harder look for this type of material, which generally all four of these could be classified as low alloy quenched and tempered bolts, 2,000 series steel bolts. We initiated a survey to look at a large amount of the safety-related bolting at the Midland site to assess, based on hardness testing, how they expect that temperature to perform.

So again, our concern is not at the moment the adequacy of the specification, but the adequacy of the bolts installed. That is one of the reasons, because we have not clearly detected a definite case for saying this specification will provide the degree of assurance that we need, that we do not need to worry about bolts provided up to that specification.

We have actually decided we are looking at some of those bolts to determine whet.er or not the exhibited hardnesses, the bolts with those exhibited hardnesses can withstand the stresses which we anticipate.

MR. MATHIS: Did you pick these wide variances up in your QA program or did you pick them up when you were actually installing them in the field?

MR. SLAGER: They were picked up in our experience. The QA program does require us to react to our problems. So in that way, yes, it was in reaction to our QA program.

On the other hand, a QA program, had we anticipated this kind of a problem, the QA program would have required us to search for that problem prior to installation.

MR. OKRENT: How are you judging what constitutes an adequate sample of the installed bolts? I guess you decided the ASTM was not adequate, apparently.

MR. SLAGER: Generally, we're looking on a statistical basis using a 95 percent probability and 90 percent confidence level, basically, in the hardness results.

If I may return specifically --

MR. OKRENT: We're through.

MR. SLAGER: -- to the question of the reactor vessel anchor bolts.

Carl, may I have the second slide.

(Slide.)

Again, repeating some of what I said earlier, our experience in that case is that within approximately eight months of preloading the reactor vessel anchor bolts, three of the bolts in Unit 1 failed. A failure analysis was performed on those bolts and concluded that the cracking mechanism was stress corrosion, cracking to a limited depth of I believe 10 mils or less, followed by fracture due to generally low toughness of the same material.

The preload for these bolts was approximately 92 ksi. Harnesses in the area of failures were as high as Rockwell C-48. That would compare to a specified Rockwell C-38.

Our resolution in dealing with the fact that we had three broken bolts, other bolts in the support system which were called into question as to their ability to support loads, was to first of all lower the prestress on all the anchor bolts for both Unit 1 and Unit 2 to 6 ksi maximum. The prime purpose of lowering to 6 ksi maximum was to lower the stress intensity on any presumed crack in the bolts, to lower that stress intensity to a point below KSSCC or the critical stress intensity for stress corrosion cracking.

Since obviously those anchor bolts were installed to support loads with a 6 ksi preload and with the presumed cracks in the bolts, we concluded it was no longer possible to support all of the loads for which the anchor bolts were originally installed for. So in order to take a major portion of those loads, upper lateral supports are being added to the reactor vessel.

These are 12 supports that stick out from the primary shield wall and come close to the reactor vessel during normal operation, and are specifically there to absorb LOCA loadings from pipe breaks.

Also, as I indicated, we presumed that the remaining 93 out of 96 bolts are degraded in their ability to support accident loads, short-term loads. Therefore we have limited the accident loads to 70 percent of the proof load, which we were able to load these up to 70 ksi minimum. And ideally, since we prohibited stress corrosion cracking from continuing, conceivably we could preload those bolts to the same 75 ksi during an accident.

However, for purposes of our tests we are only allowing those to go up to 70 percent of the ksi.

MR. OKRENT: What is involved in replacing the bolts that failed?

MR. SLAGER: The -- the most effective way -- because these bolts are placed in two rings, 48 bolts on an inner ring and 48 bolts on an outer ring -- they are seven feet, six inches long. So therefore the space between the bottom of the skirt and the bottom of the vessel is approximately that height. You can't get a seven-foot bolt up straight through the thing.

Also, even the bolts on the outer side of the ring, the vessel just above the skirt goes out somewhat, so you could not get the bolts straight out.

So it would involve chipping the bolts out, reinstalling the bolts, replacing the concrete around them, and then retensioning them to whatever level. I think that about sums up what it would take.

We had not anticipated lifting the vessel. That would conceivably be another way, but that would leave the question of whether you could really get those bolts out. There is a lot holding them in place. We have studied this option.

At the very beginning there was also, in addition to the difficulty, almost an impossibility of replacing those bolts. If you replace the bolts, you have to replace the concrete which we chip off. You cannot trust the bond between the new concrete and the old concrete.

So we spent a lot of time studying the possibility of replacing the bolts, and this is based on a technical basis.

MR. OKRENT: In view of the difficulty with the replacement, what is it that in your opinion? The bolts missed their specifications and not only got through the fabrication process, but got to the point of being buried in concrete. I am just trying to understand.

What in your opinion was the principal deficiency that led to a situation that is less than ideal and involves a non-trivial correction?

MR. SLAGER: Speaking of the reactor vessel anchor bolts, the principal deficiency in that case was that the vendor did not --

MR. MATHIS: Well, and I gather from what you said that your QA program did not pick it up. What do you do in your QAS program? You do a receiving inspection, I assume. What about chemistry?

MR. SLAGER: No, we do not do a chemistry or a hardness check. We did not do hardness or chemistry checks.

(Laughter.)

MR. MATHIS: It sounds like your QA program had some good holes in it.

MR. OKRENT: Is the Staff fully satisfied with the current status and remedies with regard to bolting?

MR. SELLERS: My name is Dave Sellers. I'm with the Materials Engineering Branch.

As far as the current status of the Midland bolts, yes. We probably know more about them than any other plant.

(Laughter.)

MR. OKRENT: Well, it is Midland we're talking about today.

MR. SELLERS: The detensioning program, yes. We have information that was reported in this recent NUREG-2467, and the detensioning program we feel gets these bolts below that threshold stress for stress corrosion.

MR. OKRENT: And this is not something that is subject to a surprise over the life of the plant in your opinion?

MR. SELLERS: Not in those detensioned bolts, we do not feel like.

MR. OKRENT: Let's see. There is no reason for their tension to be changed?

MR. SELLERS: You mean increased?

MR. OKRENT: For any --

MR. SELLERS: The tension has been decreased.

MR. OKRENT: I understand that. But over the life of the plant, there is no reason under normal operation for that condition to change?

MR. SELLERS: Not that we know of.

MR. OKRENT: No temperature changes or anything that you can --

MR. SELLERS: This was taken into account for in the design.

MR. SLAGER: The temperature effects on the reactor vessel anchor bolts due to the differential thermal expansion between the concrete and the carbon steel is to take the 5 ksi which we anticipate for the preload, which is below the 6 ksi allowable, and to reduce that to approximately 1-1/2 ksi to the differential thermal expansion..

MR. MATHIS: One other question. What about this result applying to the reactor vessel bolts? What about the other bolts you mentioned on your other slide? Are you confident of those in the same manner?

MR. SLAGER: I would like to make a comment before that. Was that a question to Dave?

I'd like to return to Dr. Okrent's question about how we feel about all the bolts we have out there. Again, remembering that our condition is predominantly one of installed bolts already and our concern is the anticipated performance, we have done an analysis of the performance of the steam generator -- sorry, of the reactor coolant pump snubber anchor bolts. And a copy of that or two copies of that were given to Dave Fischer, specifically intended for Dr. Shewmon, because I understand he has a particular interest in this subject.

MR. OKRENT: Yes, he does.

(Laughter.)

MR. SLAGER: At any rate, that analysis, which analyzes these bolts for conditions of stress corrosion cracking, fracture toughness, and tensile ductile failure which would be applicable to the solved condition, produces a set of allowables for both long-term, such as preloading, and short-term, such as accident loading, that based on the observed hardnesses for the steam generator -- for the reactor coolant pump snubber anchor bolts.

We have concluded that all anticipated stresses on those bolts will fall below the allowables that that report has developed. So in that case we are anticipating no replacement of bolts.

We have done a preliminary analysis using the same methodology on the steam generator anchor bolts and due to what was initially a low, relatively low preload on those, anyway, we are not anticipating having to replace any of those bolts again, because the stresses are anticipated to be well below what we would see as appropriate allowables.

The overall survey, the fifth item on there, the survey is not complete, so we cannot draw conclusions as to how those hardnesses are likely to result in stress allowables and how those stress allowables are likely to impact on anticipated allowables.

MR. MATHIS: How do you measure the stresses on installed bolts?

MR. SIAGER: The stresses -- they're not tested, they're analyzed. If it's direct tension, you get a direct reading of the preload. If it is torquing, you get a relationship between the torque and the preload.

MR. SELLERS: The vessel bolts were

hydraulically stressed preloaded.

MR. SLAGER: But the accident loads, of course, have to be analyzed.

MR. OKRENT: Any other questions on this topic?

(No response.)

MR. OKRENT: This may not be the last you've heard of this.

(Laughter.)

MR. POLICH: My name is Richard Polich. I'm employed by Consumers Power Company in the design production department of the Midland plant project.

I'm here to discuss the fire protection program and to discuss the topic stated on the next slide.

(Slide.)

As mentioned in the May 19th meeting, fire protection is currently an SER open item. This is due to a few areas of concern that are currently being discussed with the NRC Staff. It was felt that these concerns can be suitably resolved in the near future.

Concerning the agenda topic of flooding and wetting, the Midland plant includes floor drainage in all areas of the plant from which collection of liquid due to fire protection systems is necessary. This includes all areas of the plant in which leakage, washdown, pipe rupture, or actuation of the fire water system could occur.

Areas of the plant in which sprinkler systems are necessary have or will be reviewed to ensure that critical components will not be adversely affected by wetting.

MR. OKRENT: How do you do that?

MR. POLICH: How do we review the areas?

MR. OKRENT: Yes.

MR. POLICH: We just simply check and see where water systems are supplied, see if we have any electrical cabinets in that area, see if there are any electrical pumps that could be shorted out by wetting and such.

MR. OKRENT: Are there cables that are subject to being wet down?

MR. POLICH: Yes, we have. All cabling has been tested such that we know what the water absorption factor is, and there is no concern on that.

MR. OKRENT: Is that true for 39-year-old cable? Does one know?

MR. POLICH: Are you talking about degradation of cable over time?

MR. OKRENT: I'm just asking the question.

MR. POLICH: I assume there is no problem with that.

MR. OKRENT: Why do you assume that?

MR. POLICH: Just based on the qualification testing that's been done on the cable.

MR. OKRENT: Is that part of the qualification for that kind of cabling?

MR. JACOBS: For testing, as part of the LOCA qualification it's aged to 30 years thermally and radiationwise, then subjected to light chem spray in the reactor building, and then it's also subjected to a submergence test after that.

MR. OKRENT: How about the auxiliary building?

MR. JACOBS: We use the same cable in both cases. We have restricted cable, but that cable is restricted in its application. It is mostly qualified cable for in-containment use. Like we have some cable that there was a problem with, but we have restricted its application.

MR. OKRENT: Does the Staff have some kind of systematic look at the combination of age and water outside the containment building?

MR.TEDESCO: I know aging is a factor. I don't know about aging and the water effects, whether or not that is a requirement.

MR. OKRENT: I know that was discussed quite specifically in connection with some special cabling that was being run underground. But I'm trying to find out in connection with fire how closely you look at the effects of water. This raises -- for example -- I don't know if it's the best question --

MR. TEDESCO: If you talked about LOCA conditions, where you have pre-aging and you're going to have the LOCA conditions --

MR. OKRENT: Again, I'm talking about outside containment, because inside containment you have to look at the LOCA, steam and so forth.

MR. TEDESCO: It depends on the cable, whether or not the cable is the same is used in containment.

MR. JACOBS: Yes, I think we have one case where we restricted use to outside containment. But in the other cases it's all the same cable.

MR. OKRENT: Well, I guess what I can't tell is whether there is something systematic done in the look at possibly adverse effects from water outside containment or not. What was it I was told?

MR. POLICH: In terms of cabling, basically what he is saying is all cabling in the plant has been qualified to the same standards and the same qualifications except for certain restricted cabling. That is whether that cabling is inside containment or outside containment.

MR. TEDESCO: I am just not aware of whether that was a requirement. We can check on it and let you know.

MR. OKRENT: Is there ever the possibility of sprays of water arising from a rupture in the water part of the firefighting system which could give you water where you didn't expect it? Is the question clear? Ordinarily, you have water pipes, I assume, and then outlets where the water is suppose to leave the pipes.

MR. TEDESCO: You're very creative.

I would respond to that in terms of the evaluation we do on high-volume energy line breaks outside containment, wherever a line exists that will carry fluid postulated failures are made and the results are evaluated. Some of those lines are fire lines if they contain water.

MR. OKRENT: But these in principle could be, I don't know, small lines or nominally low stress points, but they might go near some sensitive equipment that you would not really want to get wet. I'm just trying to understand whether this is looked at systematically or not.

It's sort of a systems interaction question, but it was not clear to me that it was in fact automatically covered in what we heard earlier. It might have been, or maybe it will be, is the right word.

MR. EBBERLING: Randy Ebberling, CMBE fire protection reviewer.

Part of our standard review plan, we generally ask for cables that you can allow wetting down without causing a malfunction. I believe that the ASPE branch looks at breakage of pipe, low energy break.

MR. PRATHAM: My name is Mike Pratham with Bechtel. We do analyze fire protection systems.

MR. OKRENT: What I cannot tell is whether the points of rupture are chosen in some way that might omit some particular sensitive area because it was nominally a straight run or so forth. I'm just trying to get a little bit of an idea of how this is gone after. I am not looking for a be-all and end-all answer.

Any other comments?

Why don't you continue.

MR. POLICH: On the topic of fire dampers, fire dampers are placed on all HVAC ducts which penetrate any fire barrier or fire wall. All dampers are rated for three hours. Actuation occurs by fuseable links, which releases between 160 and 170 degrees. This design basically meets all NFPA requirements or exceeds those requirements, and also the requirements of the NRC.

Considering the effects of spurious operation --

MR. MOELLER: On the fire dampers, I have a question. Is there any requirement in terms of how fast they must close?

MR. POLICH: No, there isn't.

MR. MOELLER: How fast do they close?

MR. POLICH: I'd like to refer that to Bob Berry.

MR. BERRY: Bob Berry, general supervisor, fire protection engineering.

The fire protection dampers are spring-loaded if they're in a horizontal plane. If they are in a vertical plane they may be spring-loaded or just fall by gravity.

As soon as the fuseable link releases, the damper goes shut. It is relatively instantaneous.

MR. MOELLER: Are there any specifications on how tight the damper must close?

MR. BERRY: Yes. This is covered by UL standards and these are all UL dampers. They meet the requirements of the standards.

MR. MOELLER: How tight, then, do they close? What is the specification?

MR. BERRY: They don't allow the heat to pass beyond the dampers and beyond the wall that they are installed in.

Are you talking about tight from gas tightness, air tightness?

MR. MOELLER: Yes. Is there any specification for tightness?

MR. BERRY: I don't really know.

Randy, do you know?

MR. MOELLER: I mean, I imagine heat is one thing, but I imagine there probably -- I assume you would not want fumes or something to pass through.

MR. EBERLING: The UL test is basically a fire passage or a flame passage test, and there are, as I know, no gas-tight requirements. As a matter of fact, I believe they permit a gap up to an eighth of an inch depending on the construction of the damper.

But again, it is similar -- if you can imagine a door, it is difficult to build one that is completely tight. The function is to prevent the spread of fire and not necessarily gases. It is a different type of damper.

MR. BERRY: There is a UL standard you have to meet. I'm not totally familiar with the exact details, but that is available, of course.

MR. OKRENT: How would you say the track record on these dampers is likely to compare with the track record on bolts?

(Laughter.)

MR. OKRENT: In other words, if they are tested, is there a testing procedure that you believe is adequate for these? Is every one of them tested, each one of the 1,000?

MR. BERRY: Each and every one of them, after they're installed, will be tested.

MR. OKRENT: After they're installed?

MR. BERRY: Yes, in the place they are going to be operated they will be tested and checked off to verify that they will operate in accordance with the requirements.

MR. MOELLER: Do you have any data on what percent of them do not prove acceptable?

MR. BERRY: We have not started the testing program on those yet.

MR. MOELLER: Would someone else have those data where they have tested them?

MR. BERRY: Perhaps. I don't know.

MR. MOELLER: The reason I ask, again looking at the LER's, and not necessarily fire dampers but other types of dampers, you find many reports of failures.

MR. POLICH: Were there any other questions?

(No response.)

MR. POLICH: Concerning spurious equipment actuation. Equipment which is required to achieve and maintain shutdown has been protected to assure operability of one train after any single exposure to fire. This protection ensures that power control will be available to that one train of necessary equipment.

Components whose loss of power in normal operating position will not affect the capability to achieve or maintain shutdown are assumed to either go to the loss of power position or remain in the normal operating position.

It is our position that performance of a hot shutdown analysis is unnecessary due to the design of the Midland plant. Design factors which support this position include: valve operator and pump motors for safety-related systems, three-phase power cables are routed in separate conduits and cable trains, only one division of safety-related cable are routed in any one conduit or cable tray, redundant trains are separated in accordance with Reg Guide 1.75, four separate cable spreading rooms are provided, two for each unit. Each unit has only one train of cable routed into each cable spreading room.

Cable insulation is fire rated in accordance with IEEE 384. Inside the control room, continuous manning, administrative control of combustibles, low voltage control circuits, fire detectors, and major control cabinets also above and below the systems, all reduce the potential of the fire being sufficiently large to affect redundant systems in the control panel.

Based on these reasons, it is felt that protection from a single fire provides the capability to achieve and maintain hot shutdown.

MR. OKRENT: Is this a question of difference between you and the Staff, or --

MR. POLICH: Well, the agenda topic was spurious equipment operation.

MR. OKRENT: Are they satisfied with what you said?

MR. POLICH: I'd like to let the Staff answer that question.

MR. OKRENT: I think that's fair enough.

MR. EBBERLING: I would have to say that that goes in line with our analysis of alternate shutdown, and we haven't quite completed that yet. Whether that's an adequate answer --

MR. OKRENT: I guess I couldn't tell from what you said whether one didn't have to analyze hot shutdown, because even if it occurred we know we can shut down safely, or it is so unlikely that we do not have to analyze it, or something else. Which was it?

MR. POLICH: Okay. In answer to that, we feel that we have provided sufficient protection in the Midland plant that we can achieve shutdown, given a fire in a location. That means both alternate shutdown methods, or we have provided some form of protection to ensure that we have operability of that equipment.

MR. OKRENT: So implicit in this is, you could ride out a hot short if it occurred?

MR. POLICH: A hot short related to a single fire, yes.

MR. OKRENT: Can earthquakes produce fires at Midland?

MR. POLICH: We feel -- currently we don't feel that that is a credible occurrence unless some equipment shorts, possibly causing fires. But in terms of our, for example, reactor coolant pump system, we have a lube oil collection system which is seismically designed to collect all lube oil from the reactor coolant pumps.

MR. OKRENT: You can see, I'm just trying to see whether you might have a fire in connection with something else. I'm not sure that the only place it might occur is in connection with the reactor coolant pump. In fact, I guess there are other ways.

Are there any comments the Staff wants to make on fire protection in addition to what they have said?

(No response.)

MR. OKRENT: Any questions on this?

(No response.)

MR. OKRENT: Okay.

MR. HARSHE: My name is Bruce Harshe. I'm section head of the plant control and operations section. I'm going to discuss control room habitability, specific hazards existing at the Midland plant that could affect control room habitability.

Data was collected about these potential hazards in order to establish the design basis for the plant and to identify potential worst case accident situations. A number of these situations were analyzed in detail. Based on these analyses, a number of plant protective features have been or will be instituted.

If I could have the first slide, please.

(Slide.)

First I would like to discuss what we did in the way of an offsite survey. We did a systematic survey within a five-mile radius of the plant, looking for both toxics and explosive hazards. This is a list of the facilities that we were particularly interested in.

Of course, you have the general industry. I have separated that from the large manufacturing facilities, which are basically your Dow Chemical and Dow-Corning in close proximity and basically quite large. So we investigated those two.

We also checked the water and waste water treatment facilities on that. We investigated then the transportation lines, your truck lines, railroads, waterways, your airports.

The waterways are not a problem because the velocity that goes by cannot support commerce on it. It's simply too small. Airports, we don't have any within the five-mile radius, but those that were beyond that we did check the flight paths to verify that no one was coming in low, we were not being used in the traffic pattern.

The railroads and truck lines, these turned out to be primarily associated with the chemical facilities across the river. And because of the distances associated, these were analyzed primarily as part of -- as part of those facilities. The railroads were also checked for other things that they may be carrying which would not be associated with the chemical facilities.

Finally, we looked at the pipelines that are in the immediate area, within the five-mile radius and evaluated them relative to the appropriate criteria.

Could I have the next slide, please.

(Slide.)

We then went to the onsite hazards or onsite evaluation, looking for hazards. These we quantify in fuels, such as the diesel oil that is used, and also using natural gas in our auxiliary boilers. The evaluation of that is stil ongoing.

We also looked at lubricating oils that could potentially create a problem. We investigated gases on site, such as our hydrogen-oxygen, CO-2 systems, and also the liquid chemicals that we would store. Primarily they are there for the water treatment in the makeup systems.

After survey, both the onsite and the offsite, a list of specific concerns, once they got through the initial screening, was made and a more detailed evaluation was then performed on the ones that were appropriate.

What we have found is that the explosive concerns, the explosive hazards, there were none. There were no explosive hazards that exceeded the Reg Guide 1.191, with the exception of we are evaluating the natural gas line that is on-site. That is part of the ongoing review.

Our concerns, therefore, for the control room into the facility were primarily the toxic concerns. If I could then have the next slide.

(Slide.)

The bulk of our concern is associated with the Dow Chemical and the Dow Corning facilities. This is where our releases would be coming from. Our primary protection for the plant lies in the communication from their normal response centers. We have dedicated telephone lines that connect them directly to our control room such that in the event of a problem we can be notified.

If for some reason these lines would be out of service, we have backup radio communications between the facilities and our control room. What this does is give us an anticipatory alert. We can be notified of something happening before it gets to us.

Now in the event that something should happen that the first two would not alert us to a concern at one of the facilities, we then have the hazardous gas monitoring system which is a redundant safety grade system that monitors the inlet air to the control room. It is monitoring those gases that are known to be within the five-mile radius that could reach us in a concentration that would exceed toxic levels in the control room.

Now the hazardous gas monitoring system is capable of detecting these gases and isolating the control room such that the control room remains at or less than the toxic level.

MR. LIPINSKI: How many gases are there and what are they?

MR. HARSHE: Right now we have 24 gases that we are monitoring. Even in this monitoring situation this is quite a conservative analysis. A listing of all the gases, I do have a slide that can be thrown up. I cannot list all 24 by rote. Would you want to know those? I can do that.

MR. LIPINSKI: I guess it is not important.

MR. HARSHE: Ethylene oxide, carbon tet.

MR. LIPINSKI: How many of those are explosive?

MR. HARSHE: None that would be of concern to our plant.

MR. LIPINSKI: But the time they reach us in proper concentrations.

MR. HARSHE: They cannot burn. They may still be toxic concentration. Okay.

Based on the information for notifying or protecting our control room, we would then, if appropriate -- well, HGMS -- the hazardous gas monitor -- isolates the control room directly. The telephone communications we may elect to isolate or we may not, depending on wind direction and things of this nature.

If we isolate the control room, the first thing the control room is normally run at a pressurized condition. So when the control room isolates we have bottled air that maintains that pressurization, thereby keeping out leakage, okay. This is good for a minimum of three hours. Okay.

Now after the pressurization runs out you then have a low leakage control room by design for infiltration purposes. You also have recirculation for the control room which allows air conditioning mantaining a habitable environment. Now should it become necessary at any point after some point we have a self-contained breathing apparatus within the control room for all of the individuals and we have the capability to have six hours of bottled air for these people.

Now that covers our toxic gas concerns. Now for fire we have a smoke alarm on our air intakes that alarms from the control room but the isolation of the control room is a manual operation. Once you have the manual isolation you have other protective features of the design, control room design, self-contained breathing apparatus.

As far as radiation protection we have -- we automatically isolate with radiation detectors on the air intake so that we can maintain a habitable environment of the control room. Again, low leakage pressurization, all come into effect to protect the operators.

Finally, in case you have some sort of a plant accident, we have the emergency core cooling signal going through a chain that does isolate the control room. This is an anticipatory type of action. In the event that potentially a radioactive cloud or steam line break being admitted to the control room, to preclude that possibility. Again, it is anticipatory and isolation could be -- you can unisolate as the situation is assessed.

With that, I would like to go into the

emergency response facilities and their habitability. First of all, we have the emergency off-site facility which is approximately 18 nautical miles from the plant. Because of its distance there are no special provisions made for habitability other than normal office building HVAC.

The operation support center is located on site and it does not have any particular habitability concerns associated with it but it does have two fallback positions. One is the Midland Service Center and the other is the Training Center. These are directly opposite from the control room such that if the wind is blowing towards one facility it is blowing directly away from the other facility, so that is our fallback position.

Then, finally, we have then the Tech Support Center. Now the Tech Support Center is shielded to the same conditions as the control room for radiation doses. There is radiation monitoring of the air intakes. Manual isolation is required out there.

That completes my discussion on the control room habitability and the emergency response facilities. Are there questions?

MR. MOELLER: I have a couple. This past weekend I glanced through the LERs that had reached me for the past week and I found six. San Onofre, the emergency control cleanup system failed to start after receiving a toxic gas isolation signal. Joseph Farley, the chlorine detector failed. Calvert Cliffs, the control room air conditioning system failed to start. San Onofre, both channels on the control room airborne rad monitor failed. D. C. Cook, the control room emergency ventilation system air flows were found to be inadequate. And you just mentioned your fire detectors here -- smoke detectors failed. They are supposed to secure the ventilation system in case of a fire.

Now these are problems in other plants and you have described yours -- and, of course, it sounds very good. You have this detector that warns you. Everything is fine. And yet I notice with regard to your control room that here is a memorandum from Robert Tedesco to the ASLB for the Midland plant on May 4, 1982. He cited new information for quality assurance matters among other things -- the on-site QA and QC, insulation of the HVAC systems.

These functions which were handled by the Zac company have now been assumed by Consumers Power. What assurances do I have that your control room is going to work -- the HVAC system? What were these QA problems and what have you done to correct them for the HVAC system?

MR. HARSHE: That is actually two different questions. One is concerned with the instrumentation. The other is concerned with the ventilation ducting.

MR. MOELLER: So you separate the two. If it is an air monitor that is covered by another group?

MR. HARSHE: We have just the one QA department, if that is what you are talking about. It would cover both instrumentation and duct work.

As you go through the LERs on the various detectors that have failed, my comment on that would be we have safety grade 1F mass spectrometers. These are undergoing a very rigid qualification test, operations test, of course. I am sure you are aware that they are the first ones of this nature for this specific application, yet they have a very extensive history, philosophy under much more severe conditions than are going to be seen here, such as the space program or in military actions, particularly submarines -- this type of thing.

In that respect we feel that we have certainly the best detectors that are available with the highest reliability. Again, remember that we have redundant trains such that if one system does go out of service for any reason we have a complete backup system. Okay, with that -- that is how I would like to address the instrumentation.

Now relative to the Zac concerns, perhaps I should defer that to Ben Margulio.

MR. MARGULIO: My name is Ben Margulio. I am with Consumers Power Company. I am director of the Midland Project Quality Assurance Department. The Zac Company had problems with regard to the fabrication of ducts and supports and with regard to the instrumentation of these.

The problems were not detected on a timely basis. They were not detected at the point of fabrication. They were not detected at the point of installation. There were also procedural problems. Procedures were not adequate nor were they being followed.

In response to that situation, the Midland Project Quality Assurance Department, which is a department separate from the Bechtel quality assurance department and separate from the Bechtel quality control department, the Midland Project Quality Assurance Department assumed the responsibility for quality assurance activities relating to the installation of this ducting and supports. That includes all of the primary inspection activities as well as the preventive measures with regard to the review of procedures, with regard to the review of designs, with regard to the review of inspection techniques.

Actually, we developed the inspection techiques. Since we have assumed that primary responsibility and since Zac has accepted our inspection feedback, things have been going very well.

MR. MOELLER: Does Consumers Power have an expert in the field of HVAC?

MR. MARGULIO: Yes.

MR. MOELLER: There is an employee who is an expert in this area?

MR. MARGULIO: I would say so, yes.

MR. MOELLER: Can you tell us who it is or anything about his qualifications or her qualifications?

MR. MARGULIO: I think we have people who work in the design production organization who know about heating, ventilating and air conditioning with regard to installation.

MR. MOELLER: Is this their primary field or is it a sidelight with them?

MR. MARGULIO: I think I had better defer to design production.

MR. MOELLER: I would like to know who it is.

MR. COOK: May I respond?

MR. MOELLER: Go to the mike.

MR. COOK: Dr. Moeller, I believe I would characterize any of our mechanical engineering types as those who have spent their lifetimes specializing in HVAC design activities. I believe we have a fair amount of experience in overviewing and working with HVAC installations in all of our prior work in both fossil and nuclear.

I believe the point I would make in response to the drift of your question, the problems that Zac experienced were more being able to work in the nuclear quality assurance program to meet the welding requirements and the design and installation controls that are not unique to HVAC but rather are foreign to them in their other experience. And getting people who have worked on nuclear power facilities with the experience that we have in our quality assurance department, I believe, to directly address the kind of problems that Zac was running into.

I certainly believe that we would rely on their basic experience in terms of the trade of constructing HVAC systems, which they have done a very good job on other spots.

MR. MOELLER: I think that is adequate. I cited six LERs that I just picked up last weekend. However, in a meeting of another ACRS Subcommittee a couple weeks ago we had several private consulting firm representatives and several people who contract with licensed utilities to do tests on their control rooms -- the HVAC systems there.

They revealed to us that there is a wealth of data beyond the LER data on inadequacies in such systems. Are you aware of this data pool? It is not -- I gather it does not go to INPO. It certainly does not go to the NRC Staff and it certainly is not in the LER files. Do you have access to that?

MR. COOK: Could you reference a little more specifically what group you are talking about?

MR. MOELLER: Various consultating firms. They are air cleaning or HVAC experts and they are hired by licensed utilities to go in and do various tests on their control room systems.

MR. COOK: I am afraid I cannot directly respond to your point. I know we have an extensive test program to verify the performance of the HVAC system.

MR. MOELLER: Who does that for you?

MR. COOK: I will have to do some research on that and see who the agency is, if we have a special consultant.

MR. MOELLER: I just need to know whether you do it in-house or whether you hire someone from outside. Maybe Dr. Sullivan can comment on that.

MR. SULLIVAN: I think a lot of the input that went into the design of the Midland plant came out of our experience at Palisades, which was not all that good. In fact, I gave a paper at -- I am trying to remember whether it was the 12th Air Cleaning Conference on Ventilation Systems as Air Cleaning Devices, trying to make the point, I think, which you are getting at, which is how important the ventilation system itself is in support of filtration systems and so forth.

I think we have looked at a lot of the data. Mostly we have looked at the experience we have had with what might be called standard practice in the industry with dampers, with the quality of materials that were used in ducting and in the contructing of the filter housings, for instances, themselves in terms of the depth of the filters and all that thinking went into the specifications which we worked with with Bechtel, both Ann Arbor and San Francisco, in developing the basic design for the Midland plant.

I think if you took a look at the design of the systems at Midland -- I am not sure if you got into any ventilation rooms -- but you will see the quality of the materials, the gauge of the duct work, the type of construction used in terms of welding is much superior to what one would have found in some of these earlier designed plants.

MR. MOELLER: You see --

MR. SULLIVAN: We used Eastern.

MR. SLADE: Jerry Slade, the Assistant Site Manager. The air balancing that is currently going on, I cannot tell you the name of the outfit, but we are using a consultant. We are not doing it with our own people.

MR. MOELLER: Okay, thank you. One last question on the control room. I believe you mentioned that you had the two air intakes where if there is toxic gas at one you can switch to another. How did you locate your air intakes? Did you actually do a wind tunnel test on your configuration, your design, and decide by experiment the best places to locate these two intakes?

MR. HARSHE: No.

MR. MOELLER: Then how did you do it?

MR. HARSHE: The location of the air ducts or the air intakes was done on the basis of the ingestion of gas radioactive effluent in the event of an accident. Thus, what you find is they are located by each containment above the auxiliary building, the idea being that if you have wind from one, from a direction that may cover one port, the other would have acceptable air in it.

From a toxic gas standpoint, as I believe was your original question, if you assume the release coming from off-site, the plume is -- by the time it gets to us, which is quite some distance, it is really quite broad and it would not be feasible to cover.

MR. SULLIVAN: I could add to that that again what we did was based pretty much on judgment and experience. We had experience at Palisades with the control room intake getting exhaust fumes from an auxiliary boiler, for instance. So really what we did was look at it from a point of view of what we had seen.

I can say I think the air intakes were designed and located probably more from the point of view of convenience of the equipment in the areas that were being ventilated, but at the same time we did make some specific requests which gave Bechtel direction, for instance, on the exhaust stakes as to the heights which those stacks would be relative to surrounding buildings and that sort of thing, to try to minimize the problems we had seen.

So in terms of any specific air tunnel tests, no. But in terms of looking at experience in the industry and making some adjustment in the sources, yes.

MR. MOELLER: One last question on the same subject but in a different category. You talked about, of course, Dow Chemical and Dow Corning the problem of toxic gases and different things being released. Have you analyzed a major spill of liquid into, say, the nearby river? Is there any way that a major spill of a toxic chemical on the land -- say it drained toward your plant -- could affect your plant?

Can it get into the cooling pond or can it get into any system within the plant?

MR. HARSHE: Yes. We evaluated that in great detail. No, I cannot get to us or to the Tittabawassee.

MR. MOELLER: It cannot even get to the river?

MR. HARSHE: Why is that? Down Chemical, part of their design philosophy, they have created catch basins. They would be in trouble with the EPA and all the other environmentalists if anytime somebody spilt something it went out into the river, so it is one of those things. It just does not go there.

MR. MOELLER: Has there ever been a spill that reached the river since Dow went into operation?

(Laughter.)

MR. HARSHE: I have to say to my knowledge, no. However, their facility, I believe, is 50 years old. Not in recent -- they do state that they have not had a major release or a requirement for evacuation or anything of this nature.

Now I cannot say anything about the non-toxic substances, for example.

MR. MOELLER: And for the water in the cooling lake or pond, whichever you call it, do you analyze it for any possible toxic chemicals that might have seeped through the ground or something from Dow?

MR. HARSHE: Our pond?

MR. MARGULIO: I am Ben Margulio again. The ground water is checked in various wells that are drilled throughout the site.

MR. MOELLER: Right. You check there for chemical contaminants?

MR. MARGULIO: Yes, we do. It is done periodically.

MR. MOELLER: Okay. Thank you.

MR. OKRENT: Okay, the next agenda item. How would you prefer to handle Item A, Dr. Moeller?

MR. MOELLER: I think -- I have read the response to A-1, the tritium, and it is perfectly clear. The second one, I gather when you were giving those numbers you meant this is the frequency of alerts and site emergencies and so forth.

I gather you meant per nuclear power plant. I took it as for the industry as a whole and I guess that was why they seemed very low to me. You see, what they did was they stated that an unusual event, there would be several of these per year -- an alert once every ten to 100 years, and a site emergency every 100 to 500 years.

Well, I knew that we had already had a number of site emergencies, so all I can figure is that was per reactor, then.

MS. ADENSAM: Mr. Diefetti is here, who prepared the response to that question.

MR. OKRENT: Okay. If he could just give us a quick clarification.

MR. MOELLER: Because a general emergency once every 5,000 years -- TMI was certainly a general emergency. So divide that by 70 plants.

MR. DIEFETTI: Bob Diefetti from the Division of Emergency Preparedness. What was the question, Dr. Moeller?

MR. MOELLER: The frequencies stated for these various events, are they per reactor?

MR. DIEFETTI: Yes, per reactor per year.

MR. MOELLER: Okay. That helps. That is all

I have.

MR. DIEFETTI: That was easy.

(Laughter.)

MR. OKRENT: All right. With regard to the item on overfill protection for steam generators, again there is a written response. I think rather than try to discuss the event now I think I will call it to the attention of the Committee on Friday and we may want to have some discussion on Friday of that.

MS ADENSAM: Dr. Okrent, on operating reactors?

MR. OKRENT: Yes, or those under construction right now.

MS ADENSAM: I just wanted to know if you meant specific to Midland or whether you wanted me to cover the broad subject.

MR. OKRENT: I think what I envisage is it mentioning that in fact Midland does have safety grade protection and then I will be interested in hearing what the Staff thinks is appropriate and why for the other B&W reactors and we will see where that gets us.

Let's see. That gets us to Item C, which is others, and I guess we were going to pick up the turbine question at this time, right? Is there a comment or should I ask the question I asked?

MR. HASELTON: Warren Haselton from the Staff.

MR. OKRENT: I read the response concerning what the status is of missile protection and what it says, if I can paraphrase it, is that if you use the standard review plan you would estimate on the order of one times 10^{-5} per year for the frequency of unacceptable damage. It say for both Units 1 and 2. I do not know if that means for each or if you multiply by a factor of two, but I do not care about two -- not in this case. Sometimes I do.

Then you go on to say that General Electric calculates like something times 10^{-9} per year for degeneration of missiles. This, then, leads to a probability of an unacceptable damage of something times 10^{-9} per year. So we have differences in likelihood by one or the other method which are like 10^{4}.

MR. HASELTON: Yes.

MR. OKRENT: And then it says -- and I will quote -- "It is the Staff's position that the relevant General Electric analyses be submitted to the Staff for review and acceptance in order to verify the adequacy of the Applicant's turbine inspection and test programs."

How is it you anticipate resolving this turbine missile protection issue which is an outstanding issue in the SER?

MR. HASELTON: Well, that is also an issue in many of these near-term OLs. We have been having problems with doing the reviews the way that we had been doing them in the past and we have, as a matter of fact, decided on a different approach to doing these reviews.

In the past we, for example, assumed that the probability of generating the missile was 10^{-4}. We just assumed that as a given. Then we assumed the probability of damage of something getting hit of one and then tried to calculate the probability of a strike and tried to see whether the whole thing comes out to be less than 10^{-7}.

In some cases we have been able to do that with a great deal of difficulty, a great deal of Staff time, and in looking -- taking a new look at the turbine situation, we feel we have a better way of approaching it. That is, we are trying to put our emphasis on determining a P_1 or probability of a missile formation and instead of just taking that from a given historical data.

So in this case we will have a much -- we feel we will have a much easier chance of doing the probability of a strike in a manner that will show that we will have more confidence that we will have an overall product of 10^{-7} or less.

Now I do not have the time nor am I prepared to give you a full-blown story on this. We have prepared the document that describes what we are proposing to do, what we find difficult with the old procedure. The old procedure required a great deal of detail. We have been having difficulty getting that kind of detail and we have been having difficulty getting consistent types of stories from the various utilities.

So we feel that that is a more difficult way to go and we are trying to do the new way. As I said, we prepared a document that is intended to go to the Kreeger Committee to change our approach on this. It is in the process of going through our management review at NRR now and I do not know how it is going to make out -- the first crack the Committee gets at it -- but we, of course, fully intend that at the appropriate time we will make a complete presentation to the ACRS on it.

We do not plan to change the overall goal of 10^{-7} probability of the damage from a turbine missile, but what we intend to do is try to emphasize the front end of the whole argument where we have a little more control.

If we look at the situation realistically, when we are evaluating a plant that is already built, we do not have a lot of freedom to move things around and change things. So what we do is we keep sharpening the pencils, going into more and more detail to see whether the number turns out as acceptable or not, whereas we do have some measure of control over the probability of missile generation and again we are talking about things like disk integrity -- we know a good bit about that now -- and, of course, overspeed protection systems.

We feel that we want to emphasize those areas. Now we do have an overall P^1 probability analysis from Westinghouse that is now being evaluated and we expect to get the same kind of thing from General Electric, which is why those words are in there. So on the basis of the study we have done so far we believe that the P^1 number will come down to below the 10^{-4} that we are now using as a given, as input.

So that is what the situation is. We are in the midst of not changing horses but may be emphasizing a different part of the horse in doing our analysis.

MR. OKRENT: I must confess it is really not clear to me whether you expect to get 10^{-7} by coming up with a new estimate of P^1, not having changed anything in the turbine, the overspeed control or the inspection -- just on the basis of an analysis or experience -- or whether you expect to provide some basis for reducing P^1 from what the standard review plan suggests, because you are doing something additional that gives you some basis for making a quantitative estimate or still some third possibility.

Could you help me? Which was it you were telling us?

MR. HASELTON: I think possible some of both. That is, we are now performing inspections in a timely manner of the turbine disks. That is being done. The method of determining the schedule for these is done on a probabilistic basis.

MR. OKRENT: If I could interject a skeptical comment --

MR. HASELTON: Yes.

MR. OKRENT: I can recall when steam generator tubes were being inspected on a timely basis. The trouble is, from year to year the time has had to change.

MR. HASELTON: Well, you may be right.

MR. OKRENT: Well, but that does give one a different perspective on what was the meaning of the probability number he was using last year when last year's inspection was in force and so on.

MR. HASELTON: Well, as I said, this is somewhat of a long story and I am trying to shorten it, which is why I am successfully confusing you. But we have already taken a look at the P^1 numbers that Westinghouse has come up with. All right?

MR. OKRENT: Is this a recent one?

MR. HASELTON: This is more than 10^{-4}. These are recent.

MR. OKRENT: Because the last time I remember seeing a Westinghouse number which was early on in the question of the turbine missile question, they came in with a report, as I recall, that said in fact the number was very low -- less than 10^{-7} and there was no history of Westinghouse turbine failures to back up their number.

Unfortunately, the following year the history was there were two failures.

MR. HASELTON: This report I am talking about is within the past year. It is being evaluated now by Brookhaven. I doubt whether we are going to come to the same conclusion that Westinghouse does.

The point is -- and I do not remember the probability number will possibly vary from plant to plant and machine to machine -- the P^1 probability will -- because there are different mechanical designs and different disks that are critical and different designs, different machines that Westhinghouse makes. But I suspect that we are not going to agree with an extremely low number, but I think that Westhinghouse will be able to convince all of us that the 10^{-4} number is far too large.

So we are going in that direction. As you see, we are not there yet. We do not have the whole story yet, which is why I cannot give it to you. But we are working on it.

MR. OKRENT: Okay, I guess you do not want to answer my question about whether this is -- whether this is what some people refer to as sharpening the pencil or in fact you have a change in something that gives you that number.

MR. HASELTON: I think the point is that the people who have been doing these analyses over the past year or two are convinced that there is a better way to do them and that what they are proposing is a better way to do it, that we have better control over it, we have a better unierstaniing of what the numbers are.

So that is about all I can tell you.

MR. MATHIS: May I express my ignorance? What is so magic about your objective of 10^{-7}? You went through and you said you kind of pulled it out of thin air.

MR. HASELTON: No. I think you misunderstood. The 10^{-7} has been the goal from the beginning to have.

MR. MATHIS: On that basis? That is what I want to know. What is the basis of the goal?

MR. HASELTON: I did not set the goal. I do not know, but do not confuse that with what I said about 10^{-4} was the number selected for the probability of a missile.

MR. OKRENT: Okay, I guess.

MR. HASELTON: The point I want to make is there are a lot of new plants we are evaluating now that are in the same boat as Midland.

MR. OKRENT: I guess -- just let me offer a word of caution. There are a variety of issues for plants that are in operation or near operation where things are being done differently, let us say, on plants initiating construction and so forth. It is certainly not clear that one in all cases need accomplish the same degree of safety on an individual issue, in my opinion.

On the other hand, I do not think one wants to artificially provide a seeming measure of equivalence.

MR. HASELTON: We have no intention of doing it artificially.

MR. OKRENT: Let's see. Are there other items that we have left that we were supposed to pick up on this agenda topic?

MR. SULLIVAN: Yes. There were two items that we would like to address. One was the question about the interaction, possible interaction between power supply and off-site power. The second one -- that will be a quick response. The second one will be a presentation by our Plant Manager on the drain and flushing question.

So, Bruce, could you just address that?

MR. HARSHE: Bruce Harshe, Consumers Power. The question came up about the clarification on the off-site loss of power. The plants and towers are spaced such that if you would lose one off-site power line this would not result in loss of the other line.

MR. MOELLER: So the implication --

(Laughter.)

MR. MOELLER: The implication at the meeting at Midland was perhaps they could fall on one another and that was wrong?

MR. HARSHE: Some people, I understand -- okay. There was a possibility. The question was not answered. The domino effect could occur and the answer is no.

MR. MOELLER: Could parallel lines, if one fell would it interfere with the other?

MR. HARSHE: Off-site power, no. Remember, the off-site power lines are on each side with the 345 lines in-between. If I lose an off-site power line, the other would remain intact. I might lose the 345 line, but that would be it.

MR. MOELLER: Okay. Thank you.

MR. SLADE: Before I start my response -- Jery Slade, Assistant Manager. Before I start my response I would like to rephrase the question to make sure I have it adequately charaterized.

I think your question is really a combination of two questions that I would like to deal with separately. The first one is design capability for cleanup of systems. The second was our management plan for controlling occupational exposure within the plant.

MR. MOELLER: All right, fine.

MR. SLADE: In terms of design capability, if I could have the first slide now --

(Slide.)

This slide shows those systems which contain radioctive fluids. All of the piping systems have the capability of being drained manually prior to maintenance activities. The tanks generally have the capability that we can override the normal low level set point for pump interlock so that we can pump the tanks dry prior to any maintenance in the tanks.

Many systems have the capability of flushing either following use normally or prior to maintenance. You can see on the chart that wherever the Ms are are those where they would only be -- they would normally only be drained as a result of a maintenance activity to be in progress. There are a few of them, probably.

Of most note or the best example I could give you would be the one for the reactor coolant sampling right here (indicating), which as a result of our reviews of the design we found that we had a problem with background in the counting laps. So we actually modified the system so we can flush that after each sample is drawn. We can flush the system and we have similar capabilities.

But that is not the normal mechanism, although we do have flushing capabilities for, for instance, resin lines and the liquid waste system.

MR. MOELLER: When you say "flush," is this with extra water that you bring in?

MR. SLADE: Yes, with utility water which is recovered and it is essentially demineralized water.

MR. MOELLER: And theoretically if it proved useful you could even flush with some sort of a decontamination solution, or is that practical?

MR. SLADE: Most of the tanks have the capability. There are feed pots there but again that would not be considered normal, and you have the capability there, but before I ever did that I would want to make sure we went through an engineering analysis of what was I going to do with that solution when I got done with it.

MR. MOELLER: Would this be routine thing to flush a particular system, or is it only done under the most unusual of circumstances?

MR. SLADE: I would like to address that in terms of the management plan. Generally speaking, our overall management philosoph is to first of all limit the source in the first place. The objective, of course, is to limit it in the reactor coolant system.

The primary way we do that is through reactivity control by not taking rapid transients and subjecting the fuel to failure in the first place.

Also, we control the primary system chemistry very closely to try to minimize the amount of crud buildup that we get in the reactor coolant system, again, keeping the system very clean. In addition to that we also control the development of new sources at other locations in the plant -- crud traps, if you will -- specifically in the auxiliary building, but any place else that they may build up.

We do that through a portion of our ALARA program. Just to characterize the ALARA program -- then I will go into each of the phases in more depth -- basically the program tries to identify sources, then to evaluate those sources and what the impact is on dose, occupational dose and then act to either minimize that exposure risk or to eliminate the source altogether, if it is possible.

I am happy to report my health physics staff was more prepared than I thought they were in this respect with the ALARA program, that we do have a program for routine surveys to identify localized sources. They have established a criteria that any place where we identify an activity level that is a factor of five above the normal activity level for that area, that we identify that as something that has to be evaluated by management to make a determination of what actions are we going to take.

In terms of evaluation of the sources, there are several considerations that we use in making that evaluation. The first, of course, is area occupancy. Is it an area that is occupied a lot or very infrequently?

Second, the exposure would be required in order to keep that area up. We do not want to incur a greater exposure for decontamination than we want for the maintenance activity that might have to take place. The third is the dose rate. Again, we are concerned with getting dose rates that could be so high that eventually we would preclude the ability to ever go in that area to clean it up. So we also evaluated that.

The other consideration is the available methods for reducing the dose rates so that if we can reduce the exposure through flushing without actually exposing personnel, that that would be the preferred method and it would be more likely that we would follow through with an action in that respect.

MR. MOELLER: Is your liquid waste management system -- does it have an adequate capacity to handle flushings and cleanups?

MR. SLADE: Limiting flushing, yes. I do not think you would go through an extensive liquid waste system flush, but again, generally speaking, our objective is to try to control the sources as they build so that we can do it in a small portion rather than doing our whole system

MR. MOELLER: Okay.

MR. SLADE: In terms of contamination levels, for external to systems, so far we have discussed internal dose rates essentially, but external to systems we also do the same thing with our survey program, trying to identify those areas where we have a buildup of contamination and try to eliminate those, identify the source, first of all, and eliminate the source, but also to clean up the area just as quickly as possible -- really for two reasons.

The first one that led us into this in the first place was the health physics concern. What we found out in dealing with it is there is really a strong economic incentive for doing that in that we lose approximately 50 percent of our repair crew productivity as a result of suiting and unsuiting, the requirements for laundry, the administrative controls and so on. So not only do we have the health physics incentive to drive us in that direction but there is a pretty strong economic incentive.

The final step in the program, again, is to act to reduce the sources. The actions that we expect that we normally would take would be, first of all, just flushing the systems. Generally speaking, that works well for getting rid of the gross activities in the gross terms. It is not so effective for adherent scale type source terms and in fact our experience in that area where we have an inherent scale that builds up over a long period of time, flushing is not a very effective method to try to remove that. although we do continue to try.

Specifically, at our Palisades plant you would go through and we flushed drains on a routine basis and I expect we will be doing the same thing. Again, it is not every effective.

The second thing is prior to going into a specific area for maintenance, attempting to decontaminate in a specific area to the extent practical and, again, that is evaluated by the ALARA coordinator as part of the maintenance planning.

The third thing that we have done at our Palisades plant and I mentioned earlier we would consider is chemical cleaning of portions of systems.

Again, we do not encourage that but, as I said, we have found a need for that on occasion in our Palisades plant and we have undertaken that.

The final thing, of course, is that when all of the above fails, we also consider modification of the system to eliminate the source term in the trap entirely so it does not continue to recur. Again, we have established criteria, both economic criteria and health physics criteria for determiing when we will make those actions.

MR. MOELLER: Okay, thank you. That was a well presented report.

MR. OKRENT: Any other items in this category? Mr. Epler, did you want to add any comments on any of the matters in your area of interest?

MR. EPLER: I do not think so.

MR. OKRENT: Are there any other items the Subcommittee wants to raise?

(No response.)

MR. OKRENT: Then I am going to propose that we next spend a minute or two discussing the likely arrangement, tentative agenda -- whatever you wish to call it -- for the meeting with the full Committee which is scheduled to begin at 8:30 on Friday morning, June 4, and to end at 12:30. I hope that is noon.

(Laughter.)

MR. OKRENT: It may be well to save some time late in the evening. In any event, after we do this we will then get to a final item on the agenda where we will meet in closed session to talk about security matters.

The suggestion, then, for the agenda is as follows, subject to comments that my fellow Subcommittee members might make. We will begin with the Subcommittee Chairman's report. We expect that we will have one or more members of the public who will wish to make comments and that will follow the Subcommittee Chairman's report and on or around 9:00 we will get a summary of the status of the review by the NRC Staff.

We would propose that they take not more than 15 minutes to provide this summary, in which they in particular discuss the open items and other thing they think are particularly relevant, leaving some time for discussion by the Committee.

Then, beginning about 9:30 we would get into an item which we loosely call quality control issues. The question that will be raised before the full Committee is whether the experience at Midland indicates a need for some broader review of the quality control. So we would like to have the first 15 or 20 minute summary by the NRC on past experience from the beginning of construction -- not just the recent year or two -- and what the Staff position is with regard to whether or not there is a need for broader review.

By broader review that means would you look in areas where in fact your intention has not been specifically focused because settling occurred or a bolt failed or whatever, and then provide ten minutes for the Applicant to offer his opinions on the matter and then to leave some time for Committee discussion.

And if we stay on this agenda, we will have a break around 10:15 or 10:20. The next issue would relate to seismic design. We would ask that the Staff begin with a summary of their proposed requirements and why and their estimates of frequency or probability of the proposed safe shutdown earthquake and, let us say, a more severe earthquake, more severe earthquakes.

And then we would propose the Staff does this in ten minutes, that the Applicant then take ten minutes to summarize his thinking on the seismic design basis but also to tell us what he is doing in the area of seismic margin evaluation, including liquifaction. And then there would be time for discussion by the full Committee.

The fourth item specifically called out would be on inadequate core cooling instrumentation and the head vent. We will couple those two. First we would like to hear from the Staff what their position is, what they think should be done. I hope five minutes is more than enough for that, that the Applicant take five minutes to tell the Committee what the Applicant thinks should be the position and why and allow some time for the Committee to ask questions and discuss it.

The fifth item specifically on the agenda is experience with bolting or bolts -- whatever is the correct terminology. We would like to have, say, a ten minute summary by the Applicant of the experience and then we will have some discussion.

According to my overly optimistic agenda, that would get us to about 11:35 a.m., and we would then propose to provide the Committee with a long list of possible items that they may wish to have either presentations on, short presentations, or ask questions and so forth, but we are not proposing to schedule all of the available time with specific items because there are more items than we could possibly cover and it is going to be difficult to predict what they will want to hear.

So we will give them a list which includes the following, but there is no guarantee that Mr. Ebersole, for example, will not have some more questions -- fire protection systems interaction, integrated control system, the high copper welds in the vessel, the process steam system, ATWS, AC/DC system reliability, probabilistic risk assessment, auxiliary feedwater system reliability, organization, management and training, emergency operating procedures, and turbine missiles.

As I say, we do not expect that they will try to cover all of these or that this is necessarily the complete list of topics.

(Laughter.)

MR. OKRENT: Are there any questions?

(No response.)

MR. OKRENT: Well, seeing none, are there any comments the Subcommittee members would like to make? Would you like to add something specifically to the agenda? Do you think we should have emergency procedures down, for example, as the last topic? I know you brought that up at the Subcommittee meeting.

MR. MOELLER: I do not believe so because he did a good job. I was just curious whether you wanted to list any of the items from previous ACRS letters.

MR. OKRENT: Yes, I think we should at least call that to the Committee's attention -- those items --

and see what they wish to do.

MR. MOELLER: But I think, say, emergency planning and control room habitability they have done a -- they have responded to that.

MR. OKRENT: Yes.

MR. SULLIVAN: Terry Sullivan, Consumers. One of the items you mentioned which was not on the Subcommittee agenda was ATWS. Could I ask specifically what it is you are interested in there?

MR. OKRENT: It is just that this was mentioned in the construction permit letter for Midland.

MR. SULLIVAN: Yes, so --

MR. OKRENT: There are items in the construction permit letter that some Subcommittee members may feel they want to hear what the status is or how this is going to be resolved or so forth. If it were not late I would have added it to this agenda, but there are half a dozen things also that could have been added.

I guess I hinted that it is possible that the Committee will not be able to get through everything it wants to do in the few hours and they may or they may not decide that they want to see you later on the same day. I do not know just what will occur, but there is precedent for having extended discussions on the same day from other cases.

MR. SULLIVAN: The only suggestion I would make is if they do want to hear a presentation on organization and management it would best for us if that were in the morning.

MR. OKRENT: Okay. I think then you should do that when you get your first opportunity to stand up.

MR. SULLIVAN: Okay.

MR. OKRENT: They in fact have spent quite a bit of time on this subject in some prior operating license reviews. In this particular case it was my guess that they might decide that they would not devote as much time and might be willing to do it by questions. I may be wrong.

MR. MATHIS: Well, if they do want a presentation, I do think it could be very brief. You have a good enough story. I think you could run through it fairly fast. They are interested in experience.

(Laughter.)

MR. OKRENT: Okay. If there are no other comments on the proposed agenda, we will take five minutes to clear the room of people who are not supposed to be present for this discussion of security and then we will reconvene in closed session.

(Whereupon, at 8:45 o'clock p.m., the Subcommittee recessed, to reconvene in closed session.)

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

____

In the matter of: ACRS/Subcommittee on Midland Plant Units 1 and 2

Date of Proceeding: June 2, 1982

Docket Number: ______________

Place of Proceeding: Washington, D. C.

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

Jane W. Beach

Official Reporter (Typed)

Jane W. Beach

Official Reporter (Signature)

TENTATIVE SCHEDULE FOR THE
JUNE 2, 1982
ACRS SUBCOMMITTEE MEETING ON MIDLAND UNITS 1 & 2
ROOM 1046 (TENTATIVE) 1717 H ST. NW, WASHINGTON, D.C.

Approximate Time		Topic	Speaker
4:00 p.m.	I.	CHAIRMAN'S OPENING STATEMENT	D. Okrent
4:10 p.m.	II.	STATUS OF THE NRC STAFF REVIEW (Changes in open items, licensing conditions, etc. since the last Subcommittee meeting)	R. Hernan
4:20 p.m.	III.	QUESTIONS ON THE NRC STAFFS SER	D. Okrent
4:50 p.m.	IV.	ITEMS FROM PREVIOUS ACRS LETTERS	D. Hood
5:00 p.m.	V.	GENERAL TOPICS FOR DISCUSSION A. Methods to Reduce Common Cause Failure 1. Systems interaction studies 2. Changes in design resulting from previous experience	CPCo.
5:30 p.m.		B. Integrated Control System 1. What has been done to upgrade the ICS since TMI, changes brought about by B&W vs. CPCo.? 2. Failure modes & effect analysis	R. M. Hamm
6:00 p.m.		C. Seismic and Environmental Qualification of Equipment Important to Plant Safety	J.J. Zabritski
6:20 p.m.		D. DHR System Operation	L.S. Gibson
6:30 p.m.		E. Bolting and Other High Strength Material	H. W. Slager

Approx. Time		Topics	Speaker
6:40 p.m.		F. Fire Protection	R. A. Polich
		1. Potential problems for spurious actuations, flooding or wetting, damper actuation	
6:55 p.m.		G. Habitability	B. L. Harshe
		1. Control room 2. Emergency response facilities	
7:15 p.m.		H. Other	
7:30 p.m.	VI.	DISCUSSION OF QUESTIONS REMAINING FROM MAY 20-21 SUBCOMMITTEE MEETING	NRC Staff/CPCo.
		A. Questions on the Draft Environmental Statement	
		1. Tritium activity in the core. 2. Consistency of event probabilities with experience.	
		B. Staff Position on Overfill Protection for B&W SGs.	
		C. Others	
7:45 p.m.	VII.	INDUSTRIAL SECURITY	CPCo.
8:15 p.m.	VIII.	DISCUSSION OF THE MIDLAND PORTION OF THE FULL COMMITTEE MEETING	D. Okrent
8:30 p.m.		ADJOURN	

ATTACHMENT 2

TENTATIVE SCHEDULE FOR WEDNESDAY, JUNE 2
ACRS SUBCOMMITTEE MEETING

4:00	1.		Chairman's Opening Statement	D Okrent	(10 min)
4:10	2.		Status of NRC Review Change in Open Items/License Conditions Since Previous Subcommittee		(10 min)
4:20	3.		Questions to the Staff on the SER	D Okrent	(30 min)
4:50	4.		Items from Previous ACRS Letters	D Hood	(10 min)
5:00	5.		General Items		
	5:00	a.	Common Cause Failure	B L Harshe	(30 min)
	5:30	b.	ICS	R M Hamm	(30 min)
	6:00	c.	Environmental and Seismic Qualification	J J Zabritski	(20 min)
	6:20	d.	DHR System	L S Gibson	(10 min)
	6:30	e.	Bolting	H W Slager	(10 min)
	6.40	f.	Fire Protection	R A Polich	(15 min)
	6:55	g.	Habitability	B L Harshe	(20 min)
	7:15	h.	Other		(15 min)
7:30	6.		Feedback From NRC Staff		(15 min)
		a.	Response to Requests for Information During Previous Subcommittee Meeting		
		b.	Including CP Co		
7:45	7.		Discussion of Full Committee Agenda		(15 min)
8:00	8.		Security (Closed Session)		(30 min)
8:30	9.		Adjourn		

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5/2/82

NRC STAFF RESPONSES TO QUESTIONS BY

THE ACRS SUBCOMMITTEE DURING MEETING OF

MAY 20-21, 1982 ON MIDLAND PLANT, UNITS 1 AND 2

1a. What is the staff's criterion for turbine missiles?

Answer

The SRP Section 2.2.3 risk acceptance guidelines that are used for potential accident situations in the vicinity of the plant are and will continue to be used in determining the sufficiency of protection against turbine missiles.

During the past several years the results of turbine inspections at operating nuclear facilities indicate that cracking to various degrees has occurred at the inner radius of turbine disks, particularly those of Westinghouse design. Within this time period, there has actually been a Westinghouse turbine disk failure at one facility - Yankee Atomic Electric Company. Furthermore, recent inspections of General Electric turbines have also resulted in the identification of disk bore cracks.

In view of current experience and NRC safety objectives, the NRC staff intends to emphasize the turbine missile generation probability (i.e. turbine system integrity) in its reviews of the turbine missile issue and eliminate the need for elaborate and somewhat ambiguous analyses of strike and damage probabilities given an assumed turbine failure rate. Although straightforward in principle, the latter calculations have to be based on detailed facility information and assumptions as to missile shape and size, missile energies, barrier penetration potential and ultimately to the likelihood of damaging a facility safety system. Generally, there are significant differences between licensees or applicants submittals and the final evaluation by the staff. Nevertheless, the staff concludes, based on our reviews of many facilities, that the probability of a turbine missile striking and damaging a safety system is in a relatively narrow range depending on turbine orientation. More refined analyses or additional calculations for other facilities are unlikely to change this conclusion. Therefore, expensive and time consuming strike probability analyses on the part of applicants/licensees and/or the NRC staff are judged to be unwarranted.

This shift of emphasis requires all nuclear steam turbine manufacturers to develop volumetric (ultrasonic) examination techniques suitable for inservice inspection of turbine disks and shaft, and to prepare reports for NRC review which describe their methods for determining turbine missile generation probabilities. These methods are to relate disk design, materials properties, and inservice volumetric inspection interval to the design overspeed missile generation probability, and to relate overspeed protection system characteristics, and stop and control valve design and inservice test interval to the destructive overspeed missile generation probability.

It should be noted that although evaluations of strike and damage probabilities are not involved in following the proposed new procedures, the effect of these probabilities are taken into account in these procedures. The new procedures are related to the NRC safety goal for turbine missiles (SRP Section 3.5.1.3) by taking the P_2 P_3 product (i.e., the strike and damage probability) to be roughly in the range 10^{-4} to 10^{-3} for favorably oriented turbines and 10^{-3} to 10^{-2} for unfavorably oriented turbines, for all plants in each category, and specifying degrees of unacceptable damage in terms of missile generation probability ranges and corresponding appropriate responses required of the applicant or licensee.

1b. What is the status of the Midland Turbine Missile Protection Evaluation?

Answer

The applicant has made an evaluation of the turbine missile risk for Midland Plant Units 1 and 2. Based on their analysis, which uses General Electric calculated probabilities for the generation of missiles from design and destructive overspeed failure of 8.7×10^{-9} per year and 5.0×10^{-9} per year, respectively, the probability of unacceptable damage for Unit 1 is 1.4×10^{-9} per year and that for Unit 2 is 1.5×10^{-9} per year. However, based on the SRP Section 3.5.1.3 recommended missile generation probabilities for missiles from design and destructive overspeed failure of 6×10^{-5} per year and 4×10^{-5} per year, respectively, the probability of unacceptable damage for both Units 1 and 2 are about 1×10^{-5} per year. These are two orders of magnitude above the NRC safety objective of 10^{-7} per year.

The applicant contends that their turbine inspection and test programs are either explicitly or implicitly incorporated in their evaluation and justify their use of the General Electric missile generation probabilities. It is the staff's position that the relevant General Electric analyses be submitted to the staff for review and acceptance in order to verify the adequacy of the applicant's turbine inspection and test programs.

2. How does the staff define "adequate" core cooling?

Answer

It is well established by calculations and experiments that adequate core cooling will occur after a reactor trip so long as a two-phase froth level (liquid level swollen by the presence of steam bubble) covers the reactor core. Thus, with the possible exception of brief intervals of complex cooling conditions associated with large break LOCAs, the existence of a collapsed liquid level above the core is evidence of sufficient coolant inventory to cover the core. The large break LOCA conditions are not a detriment to the dependability of vessel level information simply because the blowdown would be over too rapidly to pose a longstanding source of confusion.

When reactor coolant pumps are running, adequate core cooling by pumped two-phase coolant will be maintained until depletion of coolant inventory well beyond the quantity required to cover the core after pumps have been shut off. Therefore, an indication of coolant inventory loss with pumps running is indicative of an approach to inadequate core cooling conditions.

See also the response to Question 3 a - d

3a. What are the staff's criteria for direct measurement of bubbles in the vessel head?

Answer

The staff's requirements for ICC instrumentation, as defined in Item II.F.2 of NUREG-0737, are:

(a) It must indicate the existence of ICC cause by various phenomena (i.e., high-void fraction-pumped flow as well as stagnant boil-off).

(b) It must give advanced warning of the approach of ICC (i.e., inventory trending capabilility).

(c) It must cover the full range from normal operation to complete core uncovery.

3b. What ways have other PWRS found for ICC?

Answer

Westinghouse's Reactor Vessel Level Instrumentation System (RVLIS) using differential pressure, and CE's Reactor Vessel Level Measurement System (RVLMS) using heated junction thermocouples (HJTC), have both been offered for inventory trending. Both systems, in conjunction with core exit thermocouples and subcooling margin monitors, appear to meet the staff's requirements for ICC instrumentation.

3c. Are these used for Midland? If not, why not?

Answer

They are not used for Midland.

The applicant has proposed by FSAR Revision 38 to use a B&W Hot Leg Level Measurement System (HLLMS). Two trains of HLLMS are proposed for each of the Midland units to monitor the primary coolant level from the top of each hot leg. The proposed design is still in the preliminary engineering phase, and no detailed system description for HLLMS is provided in FSAR Revision 38.

Unlike the Westinghouse RVLIS, the proposed HLLMS for Midland has no dp tap at the top or bottom of the vessel. Therefore, the proposed HLLMS would not indicate void formation in the reactor head until the vessel water level reaches the hot leg nozzle.

3d. What is the status of the staff position with regard to ICC instrumentation requirements?

Answer

A briefing for the CRGR evaluation of TMI Action Plan II.F.2 requirements was given by the staff on March 24, 1982. As a result of the briefing, additional information addressing some open technical issues and a cost/benefit study for ICC instrumentation design requirements were requested. The staff expects to resolve those issues with CRGR in June 1982.

The staff has also discussed several variations of the hot leg dp monitoring system with licensees and applicants for B&W reactors. However, detailed engineering descriptions and evaluations of the concepts have not been provided for staff review. Therefore, the discussion and preliminary evaluation of dp monitoring concepts is predicated on the following assumptions:

(1) Proposed dp concepts can be shown to function in an acceptable manner with pumps tripped by calculations and testings.
(2) Concepts which do not include dp across the core (vessel bottom tap) will not provide a reliable indicator for trending a loss of coolant inventory with the pumps running.
(3) Concepts which do not include dp from the vessel head to hot leg will not provide indication of voiding in the reactor vessel head until the bubble extends to the top of the hot leg nozzle.
(4) The detailed design of proposed systems will be accomplished in an acceptable manner with hardware which can be environmentally qualified.

Our preliminary conclusions are that an acceptable dp monitoring system for B&W reactors must include the following:

(1) A dp transmitter between the vessel head and the hot leg designed to indicate voiding in the vessel head and to track vessel level to within 5 feet of the top of the core (based on lower level of the hot leg nozzle in some reactors);
(2) a dp transmitter from the top of the candy cane to a level in the hot leg which is sufficiently low to distinguish between the most severe overcooling transient and a loss of coolant inventory; and
(3) a dp transmitter sensing pressure change from a tap at the bottom of the vessel and designed to trend voiding with the pumps running, or a pump current monitor for level trending with the pumps running.

4. Did the staff conduct a thorough review of internal flooding?

Answer

Yes. The staff reviewed internal flooding at the Midland Plant from sources inside and outside the containment.

(a) Flooding Inside Containment

Each Midland containment, including the reactor vessel cavity, is designed to direct all leakage to the containment sumps which are situated at the lowest point inside containment. As discussed in SER Section 5.2.5, the two separate, adjacent sumps are 70 inches deep and have a low level alarm at 18 inches, corresponding to a release of 1600 gallons. The sumps also have a rate of change alarm set at 3/4 inch per hour (1 gpm).

The design for containment water level monitoring after an accident is addressed in SER Section 6.2.8 (NUREG-0737 item II.F.1). The water level instrumentation at the Midland Plant has a range from the bottom of the sump to 10 feet (600,000 gallons) above the reactor building floor. The maximum calculated water level following a LOCA is calculated to be 9.5 feet above the reactor building floor (which is just below the bottom of the reactor vessel). The sensitivity of the water level instrumentation is such that is can detect a 1 gpm leak in one hour.

The staff reviewed leakage detection capabilities directly associated with service water to containment air coolers after the flooding incident at Indian Point, Unit 2. Each of the Midland containment air coolers is provided with a drain pan with a high flow alarm on the pan drain line. The high flow alarm annunciates and records leakage from the service water system into the containment. The flow into and out of each pair of air cooling units is also indicated in the control room. The differential flow is recorded and alarmed in the control room.

In summary, with the above sump design features at the Midland plant, the Staff concludes that a small leak in a system inside containment could be readily detected long before filling the sumps.

(b) Flooding Outside Containment

The results of the NRC staff's review regarding flooding outside containment (performed under various SRP sections) and its evaluation are provided in Sections 3.4.1, 3.6.1, 9.3.3 and 10.4.5 of the SER. Flooding sources included in the evaluations were piping and tanks, both seismic and nonseismic, which are the major contributors.

5. a) What are the staff's criteria for requiring a PRA?
   b) How does the population distribution for the Midland site, especially within the first few miles, compare with other sites?

Answer

a) The staff presented a paper (SECY 81-20) to the Commission which proposed the PRA's or other types of special analyses be performed on a priority basis for high population density sites. The analysis in that paper which identified those sites is attached (Attachment 1). The staff recommended that PRA's be performed on an expedited basis for those sites in Groups IV and V, designated as "Above Average" and "Significantly Above Average", respectively, but that all sites eventually be included as part of the NREP program. As can be seen from the attached analysis, the Midland site falls in Group III, "Slightly Above Average".

b) The 1970 residential population data for the Midland site for various distances out to 30 miles are shown together with similar data for several other sites on the accompanying Table 5-1. Indian Point, Zion and Limerick have been identified as the three sites which comprise Group V, designated "Significantly Above Average", in SECY 81-20. The Palisades site is representative of a typical or average site with regard to population. Also shown are the population values corresponding to 500 people per square mile, as given in Regulatory Guide 4.7. If at the time of CP review a site is projected to exceed these values at plant startup, then alternate sites having lower population densities should be considered.

   The general conclusions that can be gained form this table indicates that:

   - within 3 to 5 miles from the reactor the Midland site is among the highest in population density and that these values are also in excess of Reg. Guide 4.7.

   - beyond 10 miles from the reactor, the Midland site is close to average in population density.

Table 5-1

1970 RESIDENT POPULATION

Dist., Miles	Midland	Indian Pt.	Limerick	Zion	Palisades	500/MI^2
0-1	64	750	480	790	51	1,570
0-2	4,394	9,300	4,900	6,900	320	6,280
0-3	24,973	20,000	19,000	19,000	1,800	14,140
0-4	40,223	35,000	52,000	33,000	3,700	25,130
0-5	48,500	53,000	67,000	46,000	5,800	39,270
0-10	72,700	220,000	150,000	190,000	30,000	157,000
0-20	304,750	890,000	780,000	530,000	130,000	628,000
0-30	481,100	4,000,000	3,800,000	1,300,000	220,000	1,413,000

(Source: SECY 81-20)

Attachment 1

Prioritization of Sites with Regard to Population Density

1. Introduction

In comparing and evaluating the population around nuclear power reactor sites, the staff has long recognized that the population characteristics of a site, that is, its density and distribution, are a relatively crude measure of the consequences associated with the accidental release of radioactivity. The residual risk from an accident would depend not only upon the population density of the site, but also upon many other factors, such as reactor design, onsite and offsite management and technical support resources, external hazards, liquid pathway considerations, meteorological conditions at the time of the accident, and effectiveness and nature of public protective actions taken. In addition, the risk is not uniform for all members of the population regardless of distance from the site, but would be higher for those persons relatively close to the site, and would generally decrease with distance away from the site.

An analysis has been carried out to obtain a first-order prioritization of sites based upon population density and distribution. The discussion that follows outlines the rationale and methodology used and gives the results of this analysis.

2. Methodology

In carrying out this analysis, the following assumptions and methodology were used:

(a) All sites where a reactor was either in operation, under construction, or where a construction permit was presently under active review were evaluated. This involved a total of 93 sites.

(b) The population data used were taken from NUREG-0348, based on the 1970 census. The population data for the Fermi site as reported in NUREG-0348 are in error and were corrected for this analysis by a special computer run of the 1970 census tape.

(c) Although it is well-known that individuals closer to the reactor are at a higher level of risk, given an accident, than those more remotely located, the precise quantification of the variation of risk with distance is still somewhat uncertain. For the purpose of this analysis, the distance weighting given by the Site Population Factors (SPF), as given in WASH-1235, were used. Further, population beyond 30 miles was neglected, because the consequences at distances within 30 miles were considered to dominate any considerations of overall societal impact, and beyond 30 miles the potential population exposure differences from site to site become less sharp. Preliminary analyses carried out by the staff have indicated that somewhat differing weighting schemes, or the factoring in of population out to 50 miles, does not change the resulting prioritization of sites to a significant degree.

(d) The power level of the largest reactor at the site was multiplied by the SPF value to account, in a first-order way, for the variation of reactor fission product inventory from site to site. Only one reactor at a site was considered, even where multiple reactors exist or are contemplated, because the probability of an accident involving more than one reactor simultaneously was considered negligible. Although it can be argued that the population around a 4 reactor site is at a higher level of risk than those around a single reactor site, the prioritization of sites is intended to give a measure of the relative consequences, given that an accident has occurred. The number of reactors at a site presumably effects only the probability of an accident. Also, it could be argued that a multi-reactor site would have some attributes that would reduce risk, compared to a single-reactor site, because of greater management and technical resources that can be applied to reducing either the likelihood or consequences of an accident. Using the above methodology, the reactor power level times the SPF value was calculated and tabulated for each of the 93 sites considered. The results are discussed below.

3. Results

The reactor power level times SPF (P x SPF) was calculated for each of the 93 sites. The resulting values ranged from a high value of 2980 to a low value of 6. The median value is 206; and the median site has a population of less than 100 persons per square mile, which is almost a factor of two less than the population of the average site. The sites are not listed in numerical order, since this would imply a greater degree of precision than is warranted by the uncertainties in the analysis. Also, as pointed out previously, the residual risk at a particular site cannot be measured in terms of consequences alone, since plant design and other factors are important contributors to risk. Therefore, we decided to place each site into one of five groups or categories. The variation within a given group was selected to be sufficiently small so that each site within that group is considered to have about the same ranking. In selecting the groups we decided to use the median value and factor of two variation about the median to demarcate the "average" group boundaries. The other groups were chosen as indicated below.

Group No.	Title	Range
I	Below Average	PXSPF less than one-half the median value (PXSPF < 100)
II	Average	PXSPF between one-half and twice the median value (PXSPF from 100 to 400)
III	Slightly Above Average	PXSPF between twice and four times the median value (PXSPF from 400 to 800)
IV	Above Average	PXSPF between four and eight times the median (PXSPF from 800 to 1600)
V	Substantially Above Average	PXSPF greater than eight times the median (PXSPF > 1600)

Within each group the sites have been listed in alphabetical order, as shown in the following tables.

Group V - Substantially Above Average

1. Indian Point
2. Limerick
3. Zion

Group IV - Above Average[1]

1. Bailly
2. Beaver Valley
3. Fermi
4. Millstone
5. Seabrook
6. Shoreham
7. Three Mile Island
8. Waterford

Group III - Slightly Above Average

1. Byron
2. Catawba
3. Cook
4. Cherokee
5. Erie
6. Forked River
7. Haddam Neck
8. Hope Creek
9. McGuire
10. Midland
11. Peach Bottom
12. Perkins
13. Pilgrim
14. Perry
15. Salem
16. Sequoyah
17. Susquehanna
18. Rancho Seco
19. Turkey Point
20. Zimmer

Group II - Average

1. Arkansas
2. Bellefonte
3. Black Fox
4. Braidwood
5. Browns Ferry
6. Calvert Cliffs
7. Clinton
8. Brunswick
9. Davis-Besse
10. Duane Arnold
11. Fort Calhoun
12. Fitzpatrick
13. Ginna
14. Hartsville
15. LaSalle
16. Maine Yankee
17. Marble Hill
18. Nine Mile Point
19. Oconee
20. Oyster Creek
21. Palisades
22. Phipps Bend
23. Prairie Island
24. Quad Cities
25. River Bend
26. Robinson
27. San Onofre
28. Shearon Harris
29. Summer
30. Surry
31. St. Lucie
32. Skagit
33. Trojan
34. Vogtle
35. Watts Bar
36. WPPSS 3/5
37. Vermont Yankee
38. Monticello
39. Yellow Creek

[1]Bailly and Millstone Unit 3 are the only plants in Group IV that are in the early stages of construction.

Group I - Below Average

1. Allens Creek
2. Big Rock Point
3. Callaway
4. Comanche Peak
5. Cooper
6. Crystal River
7. Diablo Canyon
8. Dresden
9. Farley
10. Ft. St. Vrain
11. Grand Gulf
12. Hatch
13. Kewaunee
14. LaCrosse
15. North Anna
16. Palo Verde
17. Pebble Springs
18. Point Beach
19. South Texas
20. WPPSS 2
21. WPPSS 1/4
22. Wolf Creek
23. Yankee Rowe

6. Does the Staff have criteria on prioritization of alarms?

Answer

Staff provides guidelines on prioritization of alarms as presented in NUREG-0700, "Guidelines for Control Room Design Reviews," Section 6.3 Annunciator Warning Systems, Subsection 6.3.1, General System Characteristics. The specific guideline follows:

"6.3.1.4 Prioritization

Because of the large number of annunciators typically found in control rooms and the likelihood that numerous alarms may come in concurrently, some logical prioritization should be applied such that operators can differentiate the most important or serious alarms from less important ones.

a. Levels of Priority

(1) Prioritization should be accomplished using a relatively small (2-4) number of priority levels.

(2) Prioritization should be based on a continuum of importance, severity, or need for operator action in one or more dimensions, e.g., likelihood of reactor trip, release of radiation. Exhibit 6.3-3 (see below) provides an example of prioritization based on three levels of prioritization.

First Priority Alarms

- Plant shutdown (reactor trip, turbine trip).
- Radiation Release
- Plant conditions which, if not corrected immediately, will result in automatic plant shutdown or radiation release, or will require manual plant shutdown.

Second Priority Alarms

- Technical specification violations (other than those associated with first-priority alarms) which if not corrected will require plant shutdown.
- Plant conditions which, if not corrected may lead to plant shutdown or radiation releases.

Third Priority Alarms

- Plant conditions representing problems (e.g., system degradation) which affect plant operability but which should not lead to plant shutdown, radiation release, or violation of technical specifications.

b. Priority Coding

(1) Some method for coding the visual signals for the various priority levels should be employed. Acceptable methods for priority coding include color, position, shape, or symbolic coding.

(2) Auditory signal coding for priority level is also appropriate. See Guideline 6.2.2.3 for recommended coding tehcniques."

Summarizing the staff's guidelines, prioritization should be:

1. Accomplished using a relatively small number of levels;
2. Based on a continuum of importance, severity or need for operator action; and
3. Presented to the operator through use of coded signals.

7. What are the staff's criteria or requirements for ICC controls under conditions where the control room has been evacuated, e.g., due to a fire?

Answer

There are no criteria for specific ICC controls on the alternate shutdown panel. However, the shutdown panel does record primary system pressure and temperature.

8. What is the basis for the Staff's finding that manual operation of the Decay Heat Removal valves is acceptable?

Answer

Section 5.4.4 of the SER provides the Staff's conclusions regarding manual actions outside the control room necessary for achievement of cold shutdown at the Midland Plant. The Midland DHR system design requires local operator action to align the DHR suction valves from the reactor building sump to the RCS hot leg before the system can be brought into service. The staff's review of the Midland DHR design has been performed recognizing that manual action outside the control room in the absence of a postulated single failure is, in general, not consistent with RSB Branch Technical Position 5-1 for Class 2 plants (i.e., plants with CPs docketed before January 1, 1978 and OLs issuance scheduled on or after January 1, 1979). Two of the more significant factors of the Staff's evaluation are; (1) the time available for the action, and (2) accessibility of the operator to the valve. Review of the latter consideration is continuing.

a. Time Consideration

The design of the DHR system requires manual operator action outside the room between 6 to 30 hours during a cooldown to align the DHR suction valves. Once the DHR system is aligned, it can be operated from the control room without further remote manual action. In view of the ample time available for operator action and the ability of the DHR system to be operated remotely once properly aligned, the staff concludes that the system meets the requirements of BTP RSB 5-1 and is therefore acceptable, subject to resolution of the accessibility item below.

b. Accessibility

The manual DHR valves are located in the lower level of the auxiliary building, six levels below the control room. The valves are equipped with reach-rods which pass through a concrete wall between the auxiliary building hallway and the room housing the manual valves to reduce the radiation exposure to the operator from radioactivity which might be contained in the DHR water. In the SER, we note that the applicant is required to provide an evaluation of the environment which might exist in the vicinity of the valve hand wheels and in the passages which must be traversed between the control room and the manual DHR valves. The evaluation should consider all potential accident conditions (e.g., fire, radiation leaks in systems contained in the auxiliary building, small break loss of coolant accidents that are subsequently isolated and require RHR cooling) which might necessitate that the plant be brought to cold shutdown.

9. Will the staff require SG overfill protection on operating B&W 177 plants?

Answer

As discussed in the work scope and schedule for Task II.E.5.1 of NUREG-0660, the staff will determine in the review of the modifications proposed for CP holders if the proposed modifications warrant backfit for operating plants. The staff has not at this time imposed any requirement that operating plants install additional SG overfill protection. It is also not known what hardware changes would be required, if any, to provide protection similar to that at Midland. Cost benefit studies in this area have not been performed to date.

This issue was discussed in Recommendation 2 of NUREG-0667, "Transient Response of B&W - Designed Reactors," May 1980. The conclusion was that provisions to throttle or trip the auxiliary feedwater system to avoid grossly overfilling the steam generators are subject to failures that could isolate the reactor from its heat sink. The net effect of this type of overfill protection may increase risk.

Subsequent staff review (Mattson memo to Denton, 8/8/80) agreed with the NUREG -0667 recommendation.

Some operating plants (Rancho Seco, Crystal River 3, ANO-1) have proposed installation of the SG level protection in an effort to reduce plant sensitivity as part of the AFW upgrade and program required by Item II.E.1.1 of NUREG-0737.

The need for protection against steam generator overfill resulting from main feedwater control system failure is also being reviewed as part of Unresolved Safety Issue A-47 effort on safety implications of control system failures.

10. Are the probabilities of occurrence expressed in NUREG-0654 for reactor events and alerts consistent with experience?

Answer

There are no probabilities given in the final revision of NUREG-0654, although there were some in the draft document which was issued for interim use and comment in January, 1980. In that draft the frequency for "Notification of Unusual Events" was given as once or twice per year per operating unit. With approximately 72 operating units, this would translate into between 72 and 144 "Notification of Unusual Events" per year. In the time period 1/1/82 - 5/27/82, the NRC Operations Center has logged 108 "Notification of Unusual Events". However, these 108 events have not been analyzed to determine if they would meet the general criteria given in Revision 1 to NUREG-0654. This would be necessary before any firm reliance could be placed on the data because experience has shown that many events are over-classified by licensees and what they term a "Notification of an Unusual Event" is in reality a reportable occurrence under 10 CFR 50.72.

In the draft version of NUREG-0654 the frequency of occurrence of an "Alert" was given as once in 10 to 100 years per unit and the frequency of a "Site Area Emergency" was given as once in 100 to once in 5000 years per unit. In the same five month period described above, there has been one alert (which was subsequently upgraded to Site Area Emergency). This was the Ginna incident.

11. What is the basis for the Midland DES statement that seismic events and other natural phenomena do not contribute significantly to risk?

Answer

The basis is that the WASH-1400 estimate of the probability of severe release due to earthquakes is 10^{-6} to 10^{-8}/reactor year. This probability is small (at the higher end) compared to the sum of the release probabilities in the Midland DES of 4.8×10^{-5} /reactor year. It is only about one-tenth of the sum of the probabilities of the three sequences that release the largest fractions of core inventory (8×10^{-6} /reactor year). The staff did not evaluate the probability of a severe release due to a seismic event at Midland, nor did it determine the probability of severe releases caused by in-plant events for the Midland design. Rather, the WASH-1400 results were used, rebaselined as described in the DES Appendix E.

The staff will revise the FES section in which the level of significance will be indicated to be the uncertainty of the risks presented in the statement. Further, the section on uncertainty will be expanded and the bounds of the uncertainty given as over a factor of 10 but not so large as a factor of 100.

12. Why is liver the critical organ for the fish consumption pathway and the recreation pathway shown in DES Table C.6?

Answer

The major contributors to adult dose for the fish consumption pathway are the Cesium 134 and 137 isotopes. The relative uptake by different human organs of the various radioisotopes in the fish are such that the adult liver dose is about one-third higher than the total body dose, and about twice the dose to the bone.

The more significant recreational pathway is exposure from contaminated sediments. Because this is an external exposure pathway. DES Table C.6 indicates the same dose rate to the total body and internal organs. "Liver" is only one of several organs involved and will be deleted for the FES.

13. Why is H-3 not listed in Table 5.4 of the Midland DES?

Answer

Table 5.4 contains nuclides used in the calculation of health effects following severe accidents. The contribution of H-3 health effects following a severe reactor accident is negligible compared to the contribution to health effects of the 54 nuclides in the Table.

The selection criteria used in the Reactor Safety Study to reduce the hundreds of nuclides actually present in the plant to manageable proportions for calculations includes:

half life,
total content,
relative dose contribution within a chemical group.

The factors considered in the relative dose contribution included:

radiation type and energy,
daughters produced.

Consideration of the mass of primary coolant, about 2×10^8 grams, and the concentration of about one micro-Ci/gram shows that the total content of tritium in a PWR plant is between 200 and 300 Curies. It is a beta emitter with very low end point energy, about 0.02 MeV.

14. Page 5-58 of the DES states that "a groundwater pathway for public radiation exposure and environmental contamination that would be associated with severe reactor accidents was identified in Section 5.9.3 Exposure Pathways." However, this pathway does not appear to be identified in Section 5.9.3. Is this an error? (TR 580)

Answer

The reference on DES page 5-58 to Section 5.9.3 will be deleted in the FES. As noted on page 5-58 the groundwater pathway from severe reactor accidents are associated with soluble radionuclides which might be leached and transported with groundwater to downgradient domestic wells used for drinking, or to surface water bodies used for drinking, aquatic food and recreation.

15. What are the staff's criteria regarding draining and flushing of systems?

Answer

There are no specific requirements stating that tanks or systems must be drained and/or flushed to reduce dose rates in the region prior to maintenance. However, Regulatory Guide 8.8, "Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable" (Rev. 3), states that "accumulations of crud or other radioactive material that cannot be avoided within components or systems can be reduced by providing features that will permit the recirculation or flushing of fluids with the capacity to remove the radioactive material through chemical or physical action." (Section C.2.f.(3)). The applicant's ALARA program should contain provisions for minimizing the amount of personnel time spent in radiation areas.

IN the FSAR, the applicant states that equipment or components requiring personnel attention will be designed; 1) to provide for remote draining or flushing of equipment containing radioactive material, and 2) to minimize the buildup of radioactive material and facilitate flushing of crud traps. Prior to performing maintenance work on valves located in high radiation areas, the applicant will drain adjacent radioactive components to lower the area dose rates. Pumps containing radioactive liquids will be drained prior to maintenance. Other components, such as filters, demineralizers and tanks, which have the potential for containing radioactive liquids, will be provided with drains or spray taps for flushing and/or draining purposes.

Although the frequency with which these components are drained and/or flushed is not within the scope of the staff review, Midlands ALARA program states that equipment general design considerations are directed toward minimizing radiation levels proximate to equipment or components requiring personnel attention. One way to minimize equipment radiation levels is through equipment flushing and/or draining.

ACRS Items of November 18, 1976 Supplemental Midland Report

In a letter dated October 14, 1976, the Licensing Board for a Midland hearing which began on August 16, 1976, returned the original ACRS report of June 18, 1970 to the ACRS for clarification. The clarification sought by the Board was with reference to a paragraph on "other problems related to large water reactors" identified by the Regulatory Staff and the ACRS, and which the committee considered applicable to the Midland Plant.

In response to the Board's request, the ACRS issued a "Supplemental Report on Midland Plant Units 1 and 2" dated November 18, 1976. In July 1977, the NRC Staff issued Supplement 2 to the SER for the CP review (hereafter referred to as the CP-SER) to provide an updated status and identify resolutions of the eleven items identified by the ACRS reply. These items have also been addressed in the recent OL-SER as indexed in Chapter 19. A summary of these OL-SER discussions for the eleven items follows.

ITEMS FROM 11/18/76 ACRS SUPPLEMENTAL REPORT	SER REFERENCE
2.1 SEPARATION OF PROTECTION AND CONTROL EQUIPMENT	7.7.3, APP C (USI A-47)
2.2 VIBRATION AND LOOSE-PARTS MONITORING	4.4.4.2
2.3 POTENTIAL FOR AXIAL XENON OSCILLATIONS	4.3.2.5
2.4 BEHAVIOR OF CORE-BARREL CHECK VALVES IN NORMAL OPERATION	4.4.2.3, (2.4 of SUPP 2 to CP-SER)
2.5 FUEL-HANDLING ACCIDENT	15.5.6, 9.4.2
2.6 EFFECTS OF BLOWDOWN FORCES ON CORE INTERNALS	3.9.2.3, 3.9.2.2
2.7 ASSURANCE THAT LOCA RELATED FUEL ROD FAILURES WILL NOT INTERFERE WITH ECCS	4.2.3.3
2.8 EFFECT ON PRESSURE VESSEL INTEGRITY OF ECCS INDUCED THERMAL SHOCK	5.3.5, APP C (USI A-11 & 49)
2.9 ENVIRONMENTAL QUALIFICATION OF EQUIPMENT	3.11
2.10 INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT	TABLE 1.1 6.2.8, 7.5, 11.5, 12.3
2.11 IMPROVED QA AND ISI FOR PRIMARY SYSTEM	5.2.4

2.1 SEPARATION OF PROTECTION AND CONTROL EQUIPMENT

Source: ACRS Report on 3-Mile Island, January 17, 1968.

Concern centered around the applicant's proposed use of signals from protection instruments for control purposes. ACRS recommended applicant explore possibility of making safety instruments independent of control functions.

In Supplement 2 of the CP-SER, we noted that Consumers Power Company would follow IEEE-279 dated August 1968, and would develop detailed criteria and procedures for the installation of the protection and emergency power system for BOP & NSSS scopes. These were submitted for staff review and approval prior to installation.

In OL-SER, Section 7.7.3, we note the analyses being performed by the applicant of control systems that share a common power source or common instrument line (ICS, evaporator steam demand development, NNI) to assure that failure in these power sources or sensors will not result in consequences more severe than those in Chapter 15. This is also associated with our review of RG 1.97. These analyses will be addressed in an SER Supplement.

In OL-SER, Section 7.7.4, we discuss the applicant's response to IE Information Notice 79-22 (Sept. 79) which asked whether the harsh environment from a high energy line break might cause control system malfunctions and consequences more severe than Chapter 15 analyses. Our review of the applicant's evaluation accepts the finding that consequences beyond Chapter 15 analyses would not occur.

In OL-SER, Section 7.5.2, we address the applicant's response to IE Bulletin 79-27 which questions the adequacy of plant procedures for accomplishing shutdown upon loss of power to any electrical bus supplying power for instruments and controls. We note in Section 7.5.2 our acceptance of the applicant's evaluation finding that loss of power to any one of the buses would not prevent reaching and maintaining cold shutdown.

Finally, this safety implication of control systems is discussed in Appendix C of OL-SER by USI-A-47. Midland, like other plants, will be subject to the ultimate resolution of this USI.

2.2. VIBRATION AND LOOSE PARTS MONITORING

Source: ACRS Report on Palisades (1/27/70)

ACRS recommended studies of means of inservice monitoring for vibration or the presence of loose parts in the pressure vessel and other parts of the primary system, and implementation of such means as found practical and appropriate.

In Section 4.4.4.2 of OL-SER, we note that the applicant has described the LPMS that will be used at Midland. We have evaluated the system to RG 1.133 Revision 1 and compared it with procedures used on other plants and find it acceptable. Further review matters for this system will involve Tech. Specs. for the LCO and surveillance requirements, alarm settings, baseline data acquisition, and assurance of obtaining quality data.

The precritical vibration monitoring program for Midland is discussed in Section 3.9.22 of the OL-SER. We have reviewed and accepted the program to RG 1.20. The program recognizes Oconee Unit 1 tests as valid prototypes for the internals and recognizes Davis-Besse Unit 1 as a limited valid prototype for the surveillance specimen holder tube design.

2.3 POTENTIAL FOR AXIAL XENON OSCILLATIONS

Source: ACRS Report on 3-Mile Island, January 17, 1968.

This item references continuing studies on the possible use of part-length rods for stabilizing potential xenon oscillations.

As noted in Section 4.3.2.5 of the OL-SER, this issue was resolved by start-up tests for the Oconee Unit 1 reactor. A diagonal (combination of axial and azimuthal oscillation was induced, and the reactor was monitored for 72 hours. The azimuthal component of the oscillation was damped, but the axial component was divergent. At about 70 hours into the transient, the part-length rods were used to suppress the axial imbalance, which was reduced to near zero where it was kept.

2.4 BEHAVIOR OF CORE-BARREL CHECK VALVES IN NORMAL OPERATION

Source: ACRS Report on 3-Mile Island, January 17, 1968.

The Committee requested experimental verification that vibrations would not unseat these valves during normal operation. The concern was that there was a potential for these valves to open during normal operation allowing excessive core bypass flow.

Core bypass flow is discussed in 4.4.2.3 of OL-SER. Resolution of this item by tests on a previous operating plant is discussed in Section 2.4 of Supplement 2 to the CP-SER.

2.5 CONSEQUENCES OF FUEL HANDLING ACCIDENTS

Source: Hutchinson Island, March 12, 1970

In this item, the Committee referred to the possible need for a charcoal filtration system in the fuel handling building.

The Midland spent fuel pool area ventilation system is discussed in OL-SER Section 9.4.2. In the event of a radioactive release such as from a fuel-handling accident, redundant radiation detectors in the exhaust duct isolate the normal ventilation system and automatically start the safety-related standby exhaust system. The standby exhaust system consists of two 100%

capacity trains, each having an air filtration unit and an exhaust fan. The system meets RG 1.13 and limits radioactive releases to acceptable levels by air filtration and by maintaining a negative pressure in the area to limit exfiltration. Meets GDC 61. Also meets Position C2 of RG 1.52 and Positions C1 and C2 of RG 1.140.

Radiological consequences of a fuel handling accident are discussed in OL-SER Section 15.5.6 and are well within guidelines values of 10 CFR 100.

2.6 EFFECTS OF BLOWDOWN FORCES ON CORE INTERNALS

Source: ACRS Report on 3-Mile Island, January 17, 1968.

Committee recommended Staff review the effects of blowdown forces on core internals and the development of appropriate load combinations and deformation limits.

Section 3.9.2.3 of OL-SER discusses the applicant's analyses of the reactor internals and unbroken loops of the RCPB, including supports, for the combined effects of asymmetric LOCA loads and the SSE. These analyses are presently underway and the results are to be presented to the Staff by April 1983. The applicant's analysis will utilize previous analyses for Davis-Besse 2 and 3 with appropriate adjustments. The Staff has accepted the applicant's approach and will report on the results in a supplement to the SER.

2.7 ASSURANCE THAT LOCA RELATED FUEL ROD FAILURES WILL NOT INTERFERE WITH ECCS

Source: ACRS Report on 3-Mile Island, January 17, 1968.

The Committee desired to emphasize the importance of work to assure that fuel rod failure from LOCAs will not affect significantly the ability of ECCS to prevent clad melting.

This concern was resolved by the generic rulemaking hearing on acceptance criteria for ECCS, which resulted in 10 CFR 50.46 and Appendix K to 10 CFR Part 50.

The models and evaluation of fuel clad ballooning and flow blockage are discussed in OL-SER Sections 4.2.3.3(3) and 6.3.4 which indicates compliance with 10 CFR 50.46 and Appendix K, Part 50.

2.8 EFFECT ON PRESSURE VESSEL INTEGRITY OF ECCS INDUCED THERMAL SHOCK

Source: Oconee, July 11, 1967

The Committee recommended the Staff review analyses of possible effects upon pressure vessel integrity arising from thermal shock induced by ECCS operation.

The issue of pressurized thermal shock is discussed in OL-SER Section 5.3.5 and Appendix C (USI A-49). The potential for adverse effects increase with time as degradation of material properties accrue due to irradiation. The USI-49 issue should be resolved for operating PWRs within 4 calendar years. The Staff believes that the Midland vessels will not be jeopardized by thermal shock for at least 4 calendar years. By that time guidelines from resolution of A-49 will be available for Midland. The Staff's assessment for Midland has been made recognizing that for Midland Unit 1 the limiting reactor vessel beltline material is circumferential weld (WF 70) between the upper and lower shell forgings. The rate of increase in RT_{NDT} for Midland was estimated using the methods of RG 1.99 , Revision 1.

2.9 ENVIRONMENTAL QUALIFICATION OF EQUIPMENT

Source: Palisades, January 27, 1970

The Committee recommended that attention be given to the long term ability of vital components, such as electrical equipment and cables, to withstand the environment of the containment after a LOCA.

The status of the Staff's evaluation of the Midland program for environmental qualification of mechanical and electrical equipment is discussed in OL-SER Section 3.11. As noted therein, the review is being performed using the guidance of NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment". The review is continuing and upon completion will be addressed in a supplement to the SER. The applicant provided a revised submittal on April 30, 1982. The Staff anticipates an audit in mid-June 1982.

The seismic equipment qualification program is addressed in OL-SER Section 3.10. As noted there, the review is continuing. The applicant's seismic report is to be submitted in July 1982 and an audit by our SQRT is scheduled for September 1982.

2.10 INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT

Source: Hutchinson Island, March 12, 1970

This item relates to the development of systems to control the buildup of hydrogen in the containment, and of instrumentation to monitor the course of events in the event of a LOCA.

Section 6.2.5 of the OL-SER discusses the Midland hydrogen recombiners and the hydrogen monitoring system. The Staff reviewed the design to GDC 41, 42, and 43; 10 CFR 50.44; and RG 1.7, Revision 2 and found it to be acceptable. The design is also discussed in Appendix C (USI A-48) of the OL-SER.

Section 7.5 of the OL-SER discusses accident monitoring instruments. As listed in Table 1.1 of the OL-SER, the post TMI requirements include II.F.1 "Accident Monitoring Instrumentation" (Sections 6.2.8, 7.5, 11.5, and 12.3); II.F.2 "Instrumentation for Detection of Inadequate Core Cooling" (Section 4.4.4.1); and II.F.3 "Instrumentation for Monitoring Accident Conditions (RG 1.97, Rev. 2)" (Section 7.5.3). In OL-SER Section 7.5.4 the Staff finds the information systems important to safety, including accident monitoring instrumentation are consistent with the plant safety analyses and show substantial compliance with RG 1.97, Rev. 2.

2.11 IMPROVED QA AND ISI OF PRIMARY SYSTEM

Source: Oconee July 11, 1967.

The Committee emphasized the importance of QA in fabrication of the primary system and inspection during service life.

Code requirements were exceeded during the fabrication of the Midland reactor vessel by the performance of ultrasonic examinations of welds in addition to the code required radiography. Also, since originally initiating this concern at Oconee in 1967, compliance with new requirements of codes and Regulatory Guides have provided improved quality assurance for the fabrication of the primary system.

Since 1967, considerable improvements have been made in the preservice and inservice inspection requirements for the primary system. Examples include:

A. Issuance of the ASME Section XI Code.

B. Issuance of Appendix I to the ASME Section XI Code (this appendix improved and standardized vessel ultrasonic examinations).

C. Issuance of Appendix III to the ASME Section XI Code (this appendix improved and standardized piping ultrasonic examinations).

These requirements have been (and are being) implemented during the preservice inspection at the Midland Plant. They also will be implemented during inservice inspections if they are not superseded by more effective requirements.

SER sections which discuss this issue are: 5.2.1.1, 5.2.1.2, 5.2.3, 5.2.4 and 5.4.2.1.

METHODS TO REDUCE COMMON CAUSE FAILURE

SYSTEMS INTERACTIONS

- THREE TYPES
  - Spatial
  - Functional
  - Human

SPATIAL INTERACTIONS
(Additional Plant Walkdowns)

- THERMAL GROWTH
- STRESS
- FIRE PROTECTION
- TURNOVER

SPATIAL INTERACTIONS
(Addressed by Plant Walkdowns)

- PROXIMITY
- SEISMIC II/I
- FLOODING
- HELBA

FUNCTIONAL INTERACTIONS

- ADDRESSED BY:
  - Design Controls
  - Risk Assessment
  - Control Systems Failure Evaluation
  - Preoperational Testing
  - Operating Experience Review

HUMAN INTERACTIONS

- ADDRESSED BY:
  - Operator Training
  - Control Room Design Review
  - Operating Experience Review

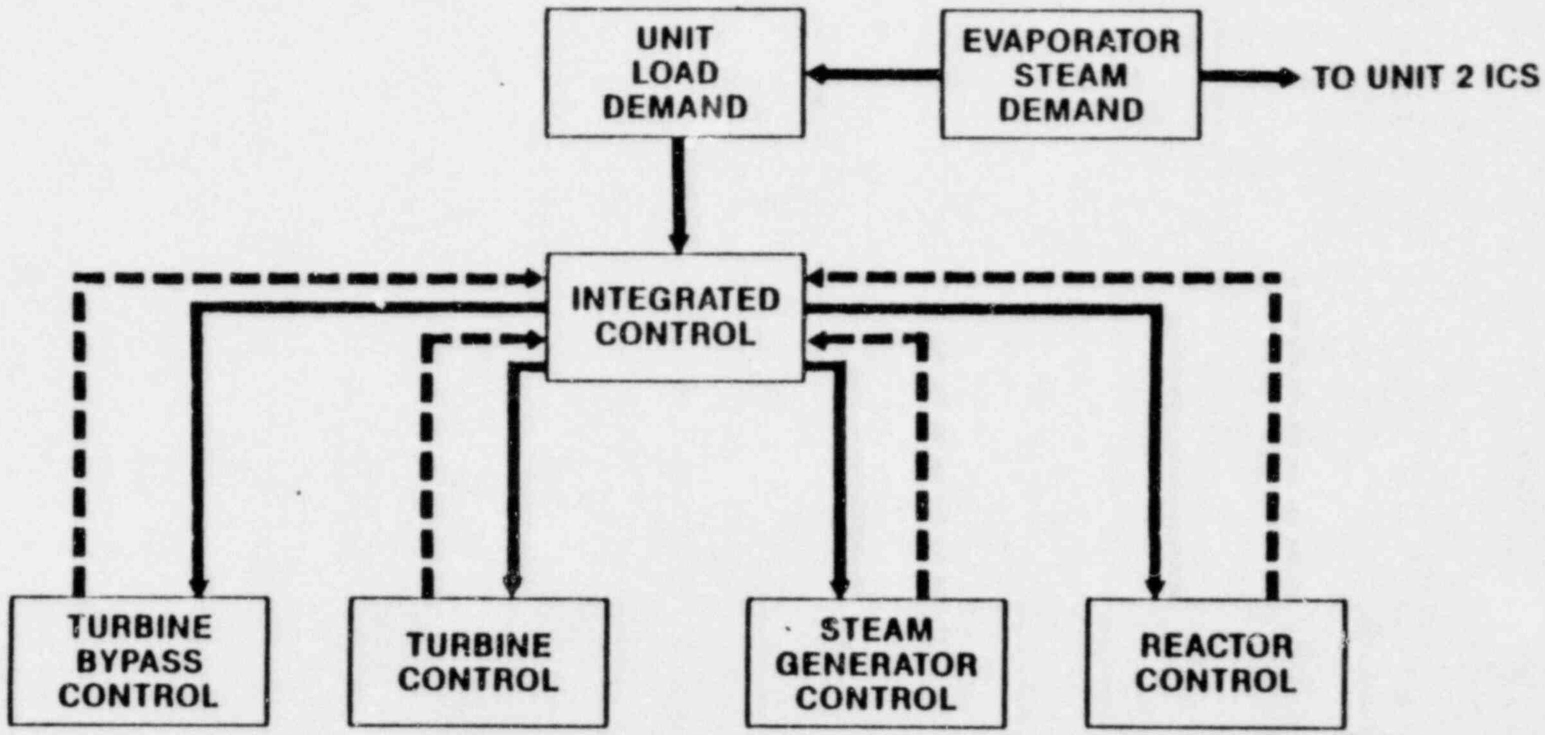
SYSTEMS INTERACTION SCOPE

- SAFETY GRADE - SAFETY GRADE INTERACTIONS

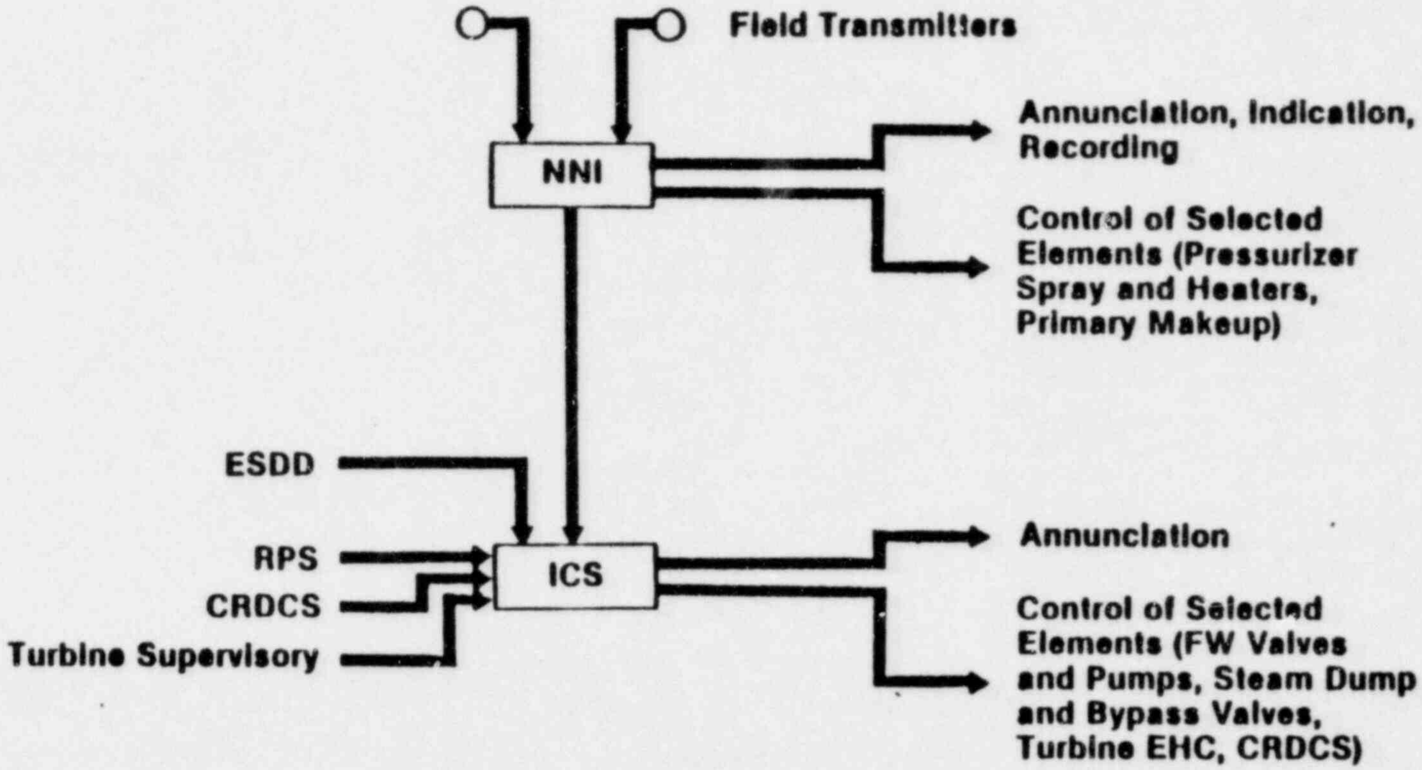
- NONSAFETY GRADE - SAFETY GRADE INTERACTIONS

INTEGRATED CONTROL SYSTEM

INTEGRATED CONTROL SYSTEM



ICS INTERFACES



MIDLAND ICS EVALUATION

- DATA EVALUATED
  - FMEA
  - Rancho Seco Incident
  - Crystal River Incident
- EXISTING DESIGN DIFFERENCES
  - AFW Safety Grade (independent of ICS)
  - Control Room Indication (independent of NNI/ICS)
- DESIGN MODIFICATIONS
  - Improved Power Supply Reliability
  - Fuse-Size Reduction
  - NNI Loss-of-Power Failure Modes
  - NNI/ICS Loss of Power Indication

CONTROL SYSTEM FAILURE EVALUATION

- CONTROL SYSTEMS EVALUATED INCLUDE:
  - Integrated Control System (ICS)
  - Evaporator Steam Demand Development (ESDD)
  - Non-Nuclear Instrumentation System (NNI)
- EFFECTS OF OTHER CONTROL SYSTEMS INCLUDED IF THEY SHARE SENSOR INPUT OR HAVE SENSOR INPUT THAT SHARES INSTRUMENT LINE WITH ICS, ESDD, OR NNI
- EVENTS CONSIDERED INCLUDE:
  - Loss of Single Sensor Input
  - Break of Instrument Lines Having More Than One Instrument with at Least One Input Into Above Systems
  - Failure of Individual Fuses or Breakers
  - Complete Loss of Power

SEISMIC AND ENVIRONMENTAL QUALIFICATION
OF EQUIPMENT IMPORTANT TO PLANT SAFETY

PARTICIPATING EQUIPMENT QUALIFICATION ORGANIZATIONS

- CPCo - OVERALL MANAGEMENT AND TECHNICAL DIRECTION
- B&W - NSSS EQUIPMENT
- BECHTEL - BALANCE-OF-PLANT EQUIPMENT
- WYLE LABORATORIES - ENVIRONMENTAL QUALIFICATION CONSULTANT
- NUTECH - SEISMIC/ENVIRONMENTAL QUALIFICATION CONSULTANT

ENVIRONMENTAL EQUIPMENT QUALIFICATION ELEMENTS

- PROGRAM DEVELOPED IN ACCORDANCE WITH CURRENT CRITERIA
- ADDRESSES QUALIFICATION OF ELECTRICAL AND MECHANICAL EQUIPMENT
- ADDRESSES HARSH AND MILD ENVIRONMENT
- RESOLUTION OF DISCREPANCIES AND DEFICIENCIES
- ENSURES QUALIFICATION FOR LIFE OF PLANT

ENVIRONMENTAL EQUIPMENT QUALIFICATION STATUS

- SUBMITTAL MADE TO NRC ON 5/3/82
  - Program Methodology
  - Qualification Data
  - Corrective Action Plans
- EQUIPMENT TEST PROGRAMS UNDER WAY
- TEST REPORT EVALUATIONS BEING COMPLETED
- INDEPENDENT AUDIT COMPLETED
- SURVEILLANCE/MAINTENANCE PROGRAMS BEING DEVELOPED
- INSTALLED EQUIPMENT BEING VERIFIED FOR CONSISTENCY WITH EQ REQUIREMENTS
- NRC AUDIT SCHEDULED FOR 6/82

SEISMIC QUALIFICATION OF EQUIPMENT ELEMENTS

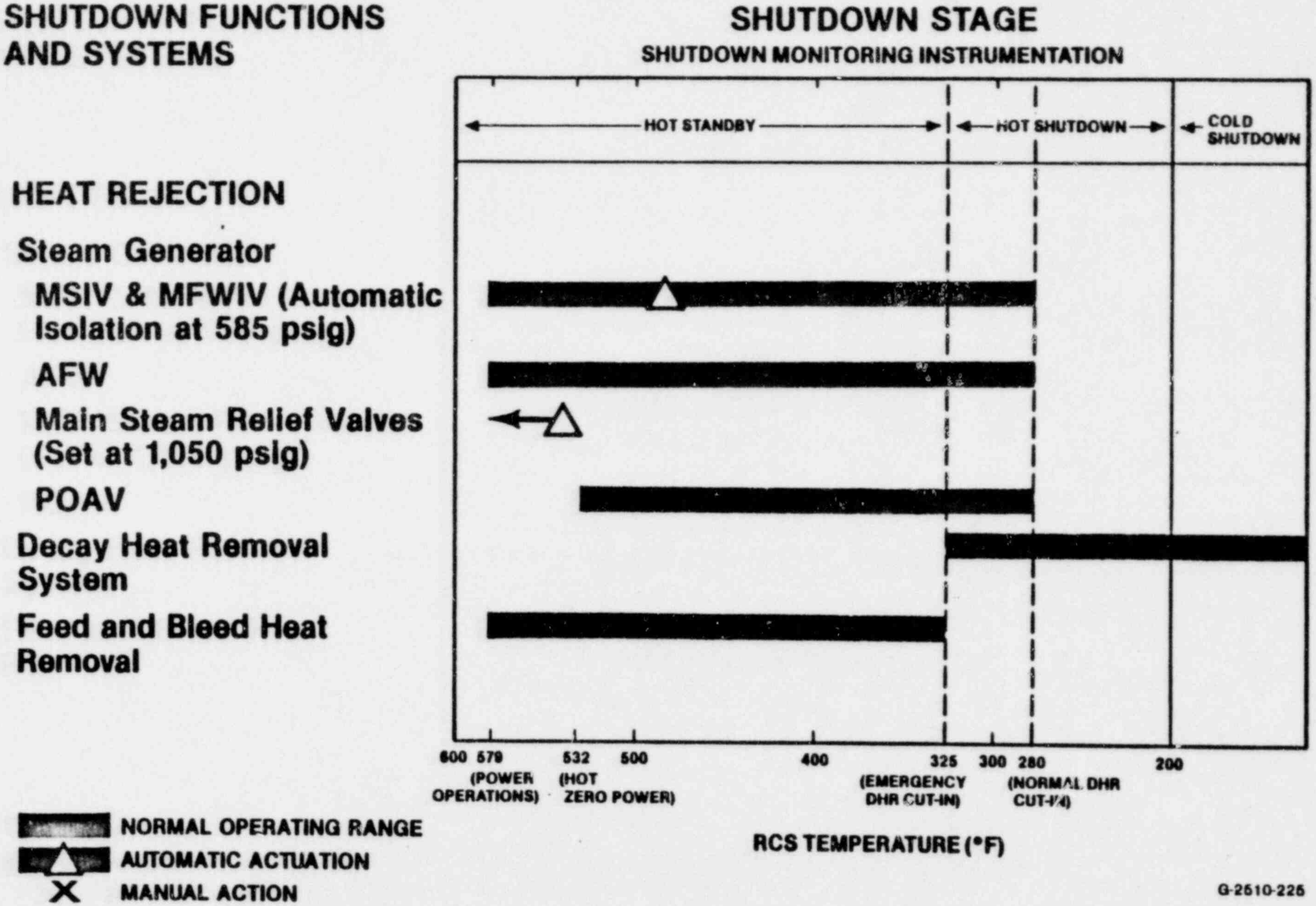
- PROGRAM DEVELOPED TO EVALUATE ALL SAFETY-RELATED EQUIPMENT
- FLOOR RESPONSE SPECTRA REVISED IN 1982
- REQUALIFICATION ACCORDING TO FSAR COMMITMENTS
  - IEEE Std 344-1971 Equipment Purchased Prior to 7/1/75
  - IEEE Std 344-1975 Equipment Purchased After 7/1/75
- EQUIPMENT TO BE EVALUATED AGAINST CURRENT NRC SEISMIC CRITERIA

SEISMIC QUALIFICATION OF EQUIPMENT STATUS

- REVISED FLOOR RESPONSE SPECTRA IN 1982
- REQUALIFICATION PROGRAM UNDER WAY
- INDEPENDENT REVIEWS IN PROCESS
- PROGRAM METHODOLOGY PRESENTED TO NRC ON 3/17/82
- SEISMIC REPORT TO BE PROVIDED TO NRC IN 7/82
- SEISMIC QUALIFICATION REVIEW TEAM (SQRT) AUDIT IN 9/82

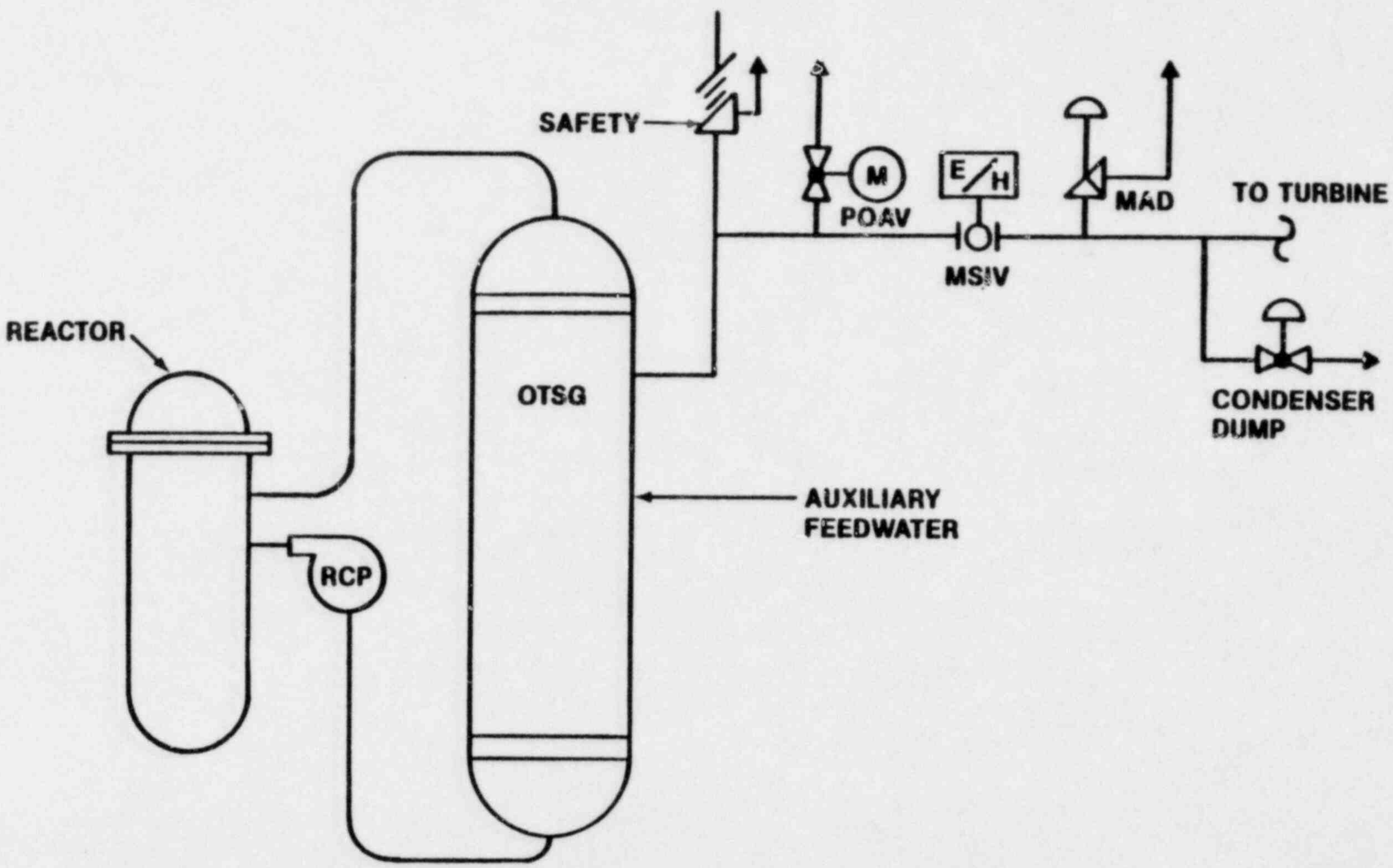
DHR SYSTEM OPERATIONS

SHUTDOWN SYSTEMS OPERATIONAL RANGE



ACRS SUBCOMMITTEE 5/82

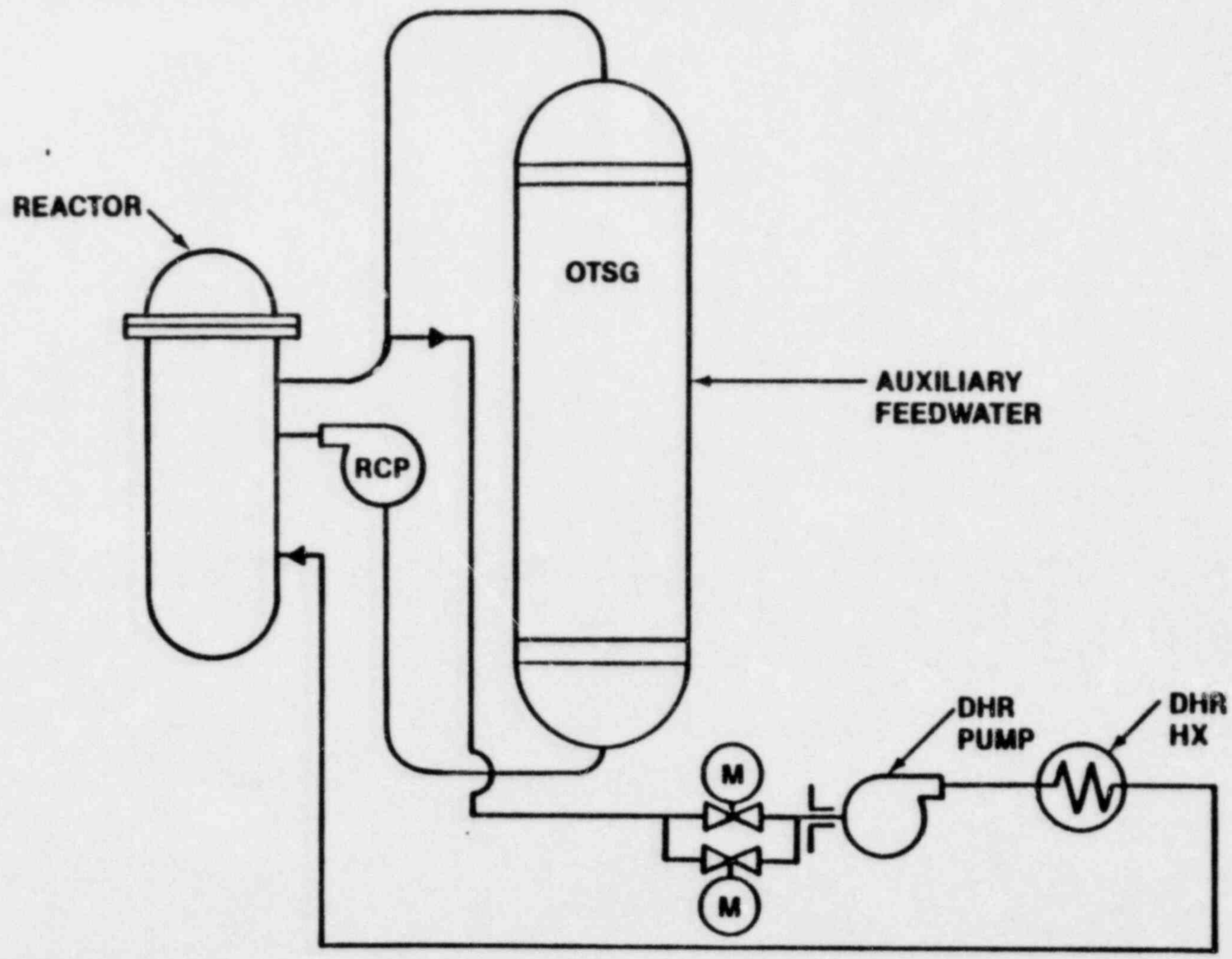
HEAT REJECTION
(Auxiliary Feedwater System)



MIDLAND UNITS 1 AND 2
ACRS SUBCOMMITTEE 5/82

G-2510-229

HEAT REJECTION
(Decay Heat Removal System)



BOLTING AND OTHER HIGH STRENGTH MATERIAL

MIDLAND LOW-ALLOY QUENCHED AND TEMPERED BOLTING

- UNIT 1 REACTOR VESSEL ANCHOR BOLTS
- PIPE WHIP RESTRAINT BOLTS
- STEAM GENERATOR ANCHOR BOLTS
- REACTOR COOLANT PUMP SNUBBER ANCHOR BOLTS
- LOW-ALLOY QUENCHED AND TEMPERED BOLT SURVEY

UNIT 1 REACTOR VESSEL ANCHOR BOLTS

- THREE BOLTS FAILED WITHIN 8 MONTHS OF PRELOADING
- CRACKING MECHANISM - STRESS CORROSION CRACKING FOLLOWED BY FRACTURE DUE TO LOW TOUGHNESS
- PRELOAD - APPROXIMATELY 92 KSI
- HARDNESS - AS HIGH AS 48 HRC
- RESOLUTION
  - Lower Prestress - 6 KSI Max
  - Upper Lateral Supports
  - Limit Accident Loads for 70% of Proof Load

FIRE PROTECTION

FIRE PROTECTION
AGENDA TOPICS

SER Open Items

Flooding and Wetting of Critical Components

Fire Damper Actuation

Spurious Equipment Actuation

CONTROL ROOM HABITABILITY

OFFSITE EVALUATIONS

- GENERAL INDUSTRY
- WATER AND WASTEWATER TREATMENT FACILITIES
- TRUCK LINES
- RAILROADS
- LARGE MANUFACTURING FACILITIES
- PIPELINES
- WATERWAYS
- AIRPORTS

ONSITE EVALUATIONS

- FUELS
- LUBRICATING OILS
- GASES
- LIQUID CHEMICALS

PLANT PROTECTIVE FEATURES

- TELEPHONE COMMUNICATIONS
  - Dow Chemical
  - Dow Corning
- RADIO COMMUNICATIONS
- HAZARDOUS GAS MONITORING SYSTEM
- CONTROL ROOM DESIGN
  - Low Leakage
  - Pressurized
  - Recirculation
- SELF-CONTAINED BREATHING APPARATUS