NUCLEAR REGULATORY COMMISSION

In the Matter of:

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON WASHINGTON PUBLIC POWER
SUPPLY SYSTEM, UNIT TWO

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OPEN MEETING

SUBCOMMITTEE ON WASHINGTON PUBLIC POWER SUPPLY SYSTEM, UNIT TWO

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Holiday Inn
Lewis and Clark Room
1515 George Washington Way
Richland, Washington

Friday, September 3, 1982

The open meeting of the Advisory Committee on Reactor Safeguards, Subcommittee on Washington Public Power Supply System, Unit Two, was convened at 8:30 a.m.

PRESENT FOR THE ACRS:

M. S. PLESSET, Chairman
J. C. MARK, Member
J. J. RAY, Member
J. EBERSOLE, Member
W. LIPINSKI, Consultant
I. CATTON, Consultant
M. GRIESMEYER, Staff

DESIGNATED FEDERAL EMPLOYEE:

G. QUITTSCHREIBER

ALSO PRESENT:

Present for the NRC and Industry:

R. Auluck
A. Schwencer
F. Eltawila
R. T. Dodds
A. Toth
D. Willett

Present for the NRC and Industry:

W. C. Bibb
D. W. Mazur
R. G. Matlock
J. R. Honekamp
J. D. Martin
J. V. Everett
D. L. Renberger
J. E. Rhoads
R. L. Corcoran
C. M. Powers
D. T. Evans
E. A. Fredenburg
P. K. Shen
R. Johnson
B. Holmberg
G. Bouchay
R. Davidson
J. Kimball
B. Bedrosian
F. Owen
J. Sorensen
F. Markowski
S. Rifaye
T. Meade

P R O C E E D I N G S

8:32 a.m.

MR. PLESSET: The meeting will come to order and we'll proceed at once to the first item on the agenda which is emergency planning. Will the Applicant proceed?

MR. NELSON: Yes.

MR. PLESSET: Okay, fine.

MR. EVERETT: My name is Vincent Everett and I'm the manager for Emergency Prepardeness for the Supply System.

We've got a number of topics I'm going to show slides on today. I'm going to go through them kind of fast so as I go through them, if I hit a point of interest, feel free to stop me and we'll get into more discussion or if I don't cover an area of interest, feel free to ask about it.

(Slide)

Areas that I'll cover include the 10 mile and 50 mile emergency planning zone which the supply system has adopted from the regulation.

The emergency organization and the outside agencies that support us, emergency centers that we have established and several of them are under construction, the communication systems that will be in these emergency centers and the communication systems with outside agencies, the early warning system and the public relations program -- the location of WNP-2 is unique to many other utilities in that the majority of our 10 mile emergency planning zone falls on the Hanford reservation. And we have no permanent resident population there. We have approximatley 1300 people who live within our 10 mile zone, mostly in Franklin County on the East side of the River. The population is, to the best of my knowledge, the lowest population of any nuclear plant in the country.

The two counties that we deal with in our 10 mile emergency planning zone, Benton County and Franklin County. The two counties have jointly agreed in a letter of understanding to develop one operational program in support of the supply system in DOE. That program is headed up by Benton County's Deparment of Emergency Services. The Benton County has developed an emergency plan for evacuation in response to support both DOE and supply system. That plan has been submitted to the State of Washington for review and was accepted. It has been submitted to the federal emergency management agency for review, and the Regional Assistance Committee which is headed by FEMA did an interim finding, review approximately two weeks ago of the plan and established some deficiencies. The deficiencies were not new things that we were not aware of. They were items that had not been completed according to the schedules as yet. I'll cover those a little more when we get into some of our deficiencies.

Another organization, a big organization we deal with is DOE. Supply system is a member of the Hanford Contractors Emergency Planning Council that meets periodically and discusses generic emergency planning issues for the reservation. DOE and supply systems jointly work with the county in the unified programs so that we have the same emergency action levels, the same levels which we notify the counties. We have jointly established a training program for the local fire departments, police, hospitals, ambulances which we're presently conducting.

(Slide)

Our 50 mile emergency planning zone goes into 10 counties, two of which are in the State of Oregon. The State of Washington has accepted the responsibility of planning effort with the counties in the 50 mile ingested pathway that are outside the 10 mile plume exposure pathway. The State of Washington has developed an ingestion pathway plan which they have sent to the eight counties in Washington and have received favorable response from many of those counties and a willingness to participate. In approximately the next month or two, we plan to go out and have meetings with each of the counties to discuss the plan a little more and make sure there's no additional problems. Those plans will then be part of the county disaster planning program for each of these counties.

1-6 The State of Washington is coordinating this and also develops a state plan which the State of Washington comes into any of the areas within our 50 mile zone and ten mile zone to conduct radiation monitoring. So this is a state responsibility as opposed to a county responsibility.

The State of Washington plan was initially developed in 1976 along with the Ben Franklin County Plan, both in support of the supply system plan submitted to the NRC. At that time, the NRC did not approve County and State plans but they concurred in them. The State of Washington and Ben Franklin County were the first plans in the nation concurred in by the NRC. Since then, we've revised them. The big impetus on our vision of the State plan has been in support of Trojan and they've got the program in pretty good shape and for the last year they've been concentrating on the supply system. That plan has been submitted to FEMA and the comments received back from the Regional Assistance Committee and had very minor problems with it. Excuse me, go back again, I've got --

MR. MARK: Excuse me.

MR. EVERETT: Yes.

MR. MARK: You have a ten mile zone from which evacuation is part of the plan.

MR. EVERETT: Correct.

MR. MARK: The 50 mile zone does not require thinking about evacuation of people in that area, I imagine, and the 10 mile zone doesn't include any people so that's simple enough. Essentially it doesn't include any people.

If you stretch out to about 15 miles, then you've got Richland in your picture. 35,000 people, Is the plan, as you've thought of it and I'm not suggesting you should because I think it's ridiculous, a certain amount of these provisions, does it include the idea of evacuating Richland?

MR. EVERETT: The plan for the supply system that is basically a County plan does not include the evacuation of Richland. The City of Richland is developing an evacuation plan in response to the Federal Emergency Management Agency's designation of this area as a target during nuclear war.

MR. MARK: No.

MR. EVERETT: So there is an evacuation plan for Richland under development.

MR. MARK: Then out of curiosity, who thinks what would be involved in evacuating Richland? I agree that I don't believe you ought to have to and as you tell me you don't -- what in heaven's name comes to mind with the idea of evacuating Richland? Where do they go? Do they move down the street to Kennewick? Or move across to the seaside? Or what the devil do they have in mind?

MR. EVERETT: For the plan that they will be developing for a nuclear war situation I'm not sure. As far as supply systems, the areas we've looked at are the Columbia Center which is approximately half way between Richland and Kennewick. The Ben Franklin County Fairground which is in Kennewick and the football fields in Pasco and Kennewick. So we are not looking in an evacuation of that situation, sending them outside the tri-cities.

MR. MARK: Well, I'm not suggesting you should. I was merely mildly curious as to what one would have in mind if one thought of anything. There's no place to go, that's worth going to.

MR. PLESSET: He's made a value judgement. We'll go on. Thank you, Mr. Mark.

(Slide)

MR. EVERETT: The State of Oregon is a second state that's in our 50 mile zone. We had discussions with the State of Oregon. The State takes the legal responsibility for the counties also in Oregon in the ingestion pathways and meetings are planned within the next month or so.

The Federal Emergency Management Agency has taken the position that Oregon State with an ingestion pathway plan is for Trojan, has done all the preliminary planning in the organizational establishment and communications and equipment needed in an ingestion pathway and it's a minor revision to the Oregon State plan to include the supply system in it.

The emergency organization for the supply system consists of organizations basically located in three areas. The first area is the on-site at the plant which the plant emergency director is responsible. The second area is the near-site emergency operations facility which the recovery manager and his staff are responsible for. The third location is the headquarters building there in North Richland which includes the managing director and the public information responsibilities.

In the plant, the initial person who may make the declaration of emergency, that authority does go all the way down to the shift manager who may be the only person on-site on that shift. The shift manager functions as plant emergency director and the recovery manager until those persons are on-site and relieved. He has all authority to make decisions on the classification of the emergency and recommendations for protective measures to the public.

Within the plant emergency director's organization, the plant organization, you have the technical support center operations which will technically support the plant control room in trying to determine where the, the emergency condition is at, what problems are occurring in the plant, and assist the operators if needed, technically.

Plant administration staff makes sure the necessary equipment, that food, that additional people that are needed and those logistic supports are taken care of.

The security force takes care of closure of the WNP-2 plant, access control, provisions for immediate access by fire and ambulance if necessary. They also will provide closure of the exclusionary boundary which is a 1.2 mile radius around the plant. And they will work with Department of Energy, if necessary, to close the whole Hanford side.

The operations manager -- excuse me. The shift manager reports to the operations manager and the operations manager supports the control room activities during the emergency.

The maintenance manager provides personnel to do repair operations. The on-site operations support center director is the person in charge of dispatching teams under the request and direction of the control room and technical support center. We have three teams report to him, a radiation safety medical emergency team which is basically the health, physics and chemistry personnel. A plant fire brigade, personnel rescue team, and also a recovery team.

The plant radiation protection manager located in the technical support center -- during the initial phases of the emergency, before the emergency operations facility is staffed up, the plant radiation protection manager will direct any initial environmental field team activities outside the site, outside the plant.

The emergency operations facility is headed by the recovery manager. The recovery manager then takes over responsibility once the EOF is established for making protective measures, recommendations to outside agencies, to requesting federal assistance and assistance from other organizations to support the supply system. He has the authority of the managing director to make commitments and recommendations that the company is requesting the other agencies to do. So the recovery manager is the person that's in charge of the emergency. Under him he has a technical group that interfaces with the on-site technical support center, a site support group which includes safety, QA, radioactive waste management, supporting activities such as scheduling and manpower and logistical support like food and additional equipment, a security operation which will interface with DOE and Ben Franklin County Sheriff's Departments on closing off the reservation or whatever other actions are necessary.

MR. MARK: I almost understood most of what you said but I can't imagine what a QA man has to do with what you're talking about.

MR. EVERETT: A QA man plays a minor role during emergency, but may play an important role during recovery effort in an attempt to get the plant in condition where it's acceptable to the NRC to allow us to start it back up.

MR. MARK: Why don't you have people who know something doing things like that? A QA man is obviously a bookkeeper of some sort.

MR. EVERETT: Yes, but we can't leave him out.

MR. PLESSET: You asked.

MR. MATLOCK: Go ahead. I don't think there are any here today, so --

MR. EVERETT: We have an off-site agency coordinator who will be responsible for making sure that the outside agencies that respond to the emergency operation facility such as the State, the County, other agencies that support us, have provisions that they need such as desks to work at, that the communications that they need are there and so on.

The EOF public information officer is a person who operates out of the EOF to collect data and information that is then passed onto the public information operations at the headquarters building.

At the EOF, there is an area which is a security training area, a large classroom in which we will conduct controlled tours by the press out to the emergency operations facility so that they can get pictures of the plant from there and also can go into the EOF and watch the operations as the conditions dictate.

The radiological emergency manager will be responsible for the field team operations of the supply system, dose projection calculations using the computerized system we're developing. He will coordinate with the State of Washington and Department of Energy or environmental field teams. During the initial phase of the emergency, the supply system may have environmental field teams out before anyone else gets out there. We will take responsibility for assessment in the 10 mile zone. Once DOE is equipped and responds, they will take over the responsibility on the reservation off of the exclusionary boundary for the supply system.

Approximately 6 hours is estimated for the State of Washington to respond and at that point, the State of Washington will take responsibility for the Ben Franklin County areas in the 10 mile zone. The supply system will still provide support and resources to these agencies as they request them.

At the headquarters, there's two main operations. The managing director operates out of the crisis management center and this center keeps the managing director up to date on what's going on. His main role during an emergency is directed toward public relations and interfacing with high officials from State and Federal and County agencies to work towards ensuring support to the supply system operation and assuring public confidence that the emergency is being handled correctly. At the headquarters building, is the emergency public information center or joint information center in which the supply systems, DOE, Ben Franklin County and the State of Washington will jointly conduct press operations in a unified effort. There is a memorandum of understanding that presently is in the Governor's office for signature which commits to this action and also the Federal Emergency Management Agency and NRC will have part of that. And the headquarters communication center which is a 24 hour staff center during normal operations, support security operations and that is the communication center being used by the headquarters personnel.

We have a number of outside organizations that will support us during an emergency. The Department of Energy will be a very large supporter of us with resources and manpower with the personnel that are available on the reservation and the equipment. We have a very large resource area unique to this side.

MR. MARK: You referred to the availability and the activity of some headquarters personnel. I presume we are talking of an office in Richland somewhere.

MR. EVERETT: Correct.

MR. MARK: Are those the headquarters personnel people? Or do they really live in Seattle or where?

MR. EVERETT: Those are headquarters people assigned to Richland.

MR. MARK: They're Richland people?

MR. EVERETT: Correct. We will use personnel from WP-3 as part of the emergency organization to support

WNP-2. We're looking at the company as a whole in looking at the best qualified people to fit in the various emergency positions. Those people from WNP-3, however, will staff up either a second or a third shift because they will not be available initially to respond. But we do have some highly qualified people there that we plan to use.

The Portland General Electric is -- we have an agreement with them to support us during an emergency a mutual letter of understanding. We are also in the process of developing an agreement with the West Coast utilities, including Pacific Gas and Electric, Southern California Edison, Sacramento Municipal Utilities District and Arizona Public Service and a joint agreement that would support any of the plants if an emergency occurred if support were requested.

Exxon Nuclear provides support with three monitoring personnel. Their main function and use would be to go along the 10 mile zone along Richland and to verify that no radiation levels are exceeding limits there.

Pacific Northwest Labs has available labs, dossimetry services, whole body counting, U.S. testing, has environmental sampling capabilities and TLD's.

Babcock and Wilcox, that's part of the WNP-1 program, General Electric instituted nuclear power operations can support us with manpower and assist us in finding equipment throughout the nation.

American Nuclear Insurers will provide support to personnel evacuated or public, if it's evacuated, Northwest Health Services with hospitals for contaminated personnel and the State and Counties. Coast Guard for for closure of the river, Federal Emergency Management Agency for assistance in communications in public affairs operations, NRC also.

(Slide)

In our facilities we have in the plant the tech support center which is located -- it's a new building being constructed outside the rad waste building, Unit Two and it's a 441 level as opposed to the control room of 501 and there are no security boundaries between those two operations during emergency, so there's close access to the two facilities.

The technical support center consists of a work area, communications area and some offices, records, a kitchenette and equipment.

(Slide)

The technical support center is built to the same capability as the control room. It will be staffed by the technical support center director and a technical staff and the plan emergency director.

(Slide)

The operations support center in the service building, it's the service building lunchroom and it's a point at which personnel that are evacuated will assemble for accountability. Those unnecessary people during major emergency would be evacuated off-site initially to the EOF. If conditions dictate, we'll send them down to the headquarters building and the operation support center director and the teams operate from here.

(Slide)

The Emergency Operations Facility is a new structure approximately 3/4's of a mile from Unit Two. It's designed to withstand serious release of radioactive material, approximately 2 feet of concrete shielding on the ceiling and the walls are covered with dirt. It's a basement concept. In the Emergency Operations Facility there are a number of areas down in the shielded area and I might point out that emergency operation facility is a part of this overall facility which is called the plant support facility. The emergency operation facility is the basement shielded part. And in there we have areas for supply system, decision making, security operations, off-site agency efforts, technical data operations where the corporate engineering staff would assist the plant with technical data. The dose assessment area for projecting doses at the ten mile zone, a back up radiological lab for supporting the plant, the whole body counters, the TLD System and some work areas. The the other parts of the plant, excuse me, the other parts of the facility, the non-shielded areas, we've identified labs that will be used if radiological conditions will allow us; we have a decontamination area, first aid area, and upstairs we've got --

(Slide)

We've got a number of classrooms which will be used for work areas and we've got the media briefing area which is a security center, security classroom I mentioned awhile ago, that we'll bring the press in and give them briefings there.

(Slide)

At the headquarters building, we have the presently called Emergency Public Information Center. One of the comments of FEMA was they'd like to see it called a joint information center so the name will change. The joint information center will be used by all agencies involved with public relations activities to get the press here to get the information and not have them going to the county emergency operation center and the state emergency operation center and other places.

The telephone response center and the rumor control center are areas to which we will try to handle the incoming telephones and advise people what's happening and people who call in we'll read the press releases to them. If people call in with assistance, we'll direct those calls to the proper person. We have some office areas for personnel, telecopy area. This facility does have emergency power that will support these areas and might point out the emergency operation facility also has emergency diesel generators, too.

(Slide)

Upstairs in the multi-purpose facility is the crisis management center which is presently the management board room and the security communication control center which is operated 24 hours a day. The security center will be the initial notification center and the plant, when the emergency occurs, a call will go to this center here and the security guard will collect the information that the operators will tell him on the forms that the State, County and Supply System and DOE agree to which are near completion and then we'll make all the necessary phone calls to notify the outside agencies within 15 minutes. Then we'll start calling supply system personnel, alerting them to the emergency so that they can respond if they're required to.

(Slide)

The emergency communications network -- we spend a lot of time working with communications. If you look back at emergencies at other plants, and at drills, you also see a deficiency shows up with communications. So we've spent a lot of time with this. We've established a radio network which in the communication center at the headquarters and also a communication center at the emergency operation facility has frequencies for the State when they respond with their radios, with DOE, with the local law inforcement agencies we have the frequency that all law enforcement agencies in this area have. We can talk to either the Benton County Sheriff, the Franklin County Sheriff, Richland police, and of these agencies.

We have frequencies where we can talk to the Coast Guard. We have the DOE frequencies. We can talk to DOE security, DOE fire department and then all supply system frequencies. During the emergency, the emergency operations facilities communication center will function as the primary radio center. The headquarters emergency communication center will function as the primary telephone center for calling people so we'll have split responsibility there. We'll probably have three to four people assigned, dedicated to communication operations.

Dedicated phones, we have dedicated phone systems which connects the plant, the emergency operations facility, the headquarters, DOE, Benton County Department of Emergency Services and County Emergency Operation Center, and the State of Washington's Emergency Operation Center, dedicated phone system with a FAX facsimile system where we can FAX the information to try to minimize the amount of occurrence in which data is taken down incorrectly over the phone. We'll just write it down to them, if it's important data, technical data, and FAX it to them. We will have the facsimile system which will give us approximately a 20 minute turn-around per page which is about as fast as we get.

Crash network is part of the dedicated phone system. With a dedicated phone system, you can selectively dial any of the various phone drops. With a crash network, you can push a single button and it rings all of them.

(Slide)

The early warning system -- supply system is presently reviewing the technical basis for the early warning system. I'm going to show you in the next slide is, what we are prepared to do at this time prior to completion of our technical review of the early warning system requirements. The early warning system will consist of two systems basically -- sirens for transient areas such as the Columbia River and the Yakima River which come into our 10 mile zone, tone activated radios for residents, permanent residents within our area. There's approximately 1300 residents in the 10 mile zone, approximately 435 homes I believe. The tone activated radios are connected to the emergency -- or will be activated by the emergency broadcast system which is KONA, 610 AM for the tri-cities.

(Slide)

If we look at our ten mile zone, this shows the points for the location of the sirens. The sirens have approximately a one mile range and we've analyzed the system, we've provided a report to the NRC and FEMA. We've got initial concurrence by FEMA that the design is acceptable and they will be installing it next year.

MR. RAY: Mr. Everett?

MR. EVERETT: Yes.

MR. RAY: There's a question in my mind. What does the public in the area understand that the sirens mean and how is that communicated to them?

MR. EVERETT: The public information program which will include a brochure that we hand out to all residents in the 10 mile zone and also will do some town hall meetings with people and possibly some newspaper advertisint. We'll state that the early warning system that is in place is an early warning system for all disasters, not just a nuclear disaster. That when these sirens go off, you are not to immediately evacuate. That is just a notification that you are to turn on your radio to the emergency broadcast system and to await further instruction. A lot of effort will be, don't evacuate.

MR. RAY: When will this information be disseminated or has it already been disseminated?

MR. EVERETT: The emergency public information brochure is being developed and it will be disseminated next spring. We hope to start the public meetings in approximately May.

MR. RAY: What are your plans for future repetition? You know, the public has a short memory if things are not favorable to them.

MR. EVERETT: It's an annual program. So each year we'll send out -- we hope to do different brochures. The brochures will also be in the information centers, will get out to Kiwanis Clubs and other organizations, if I can't give presentations. We've already done that in the last couple of years, so it's an active public information program.

MR. RAY: How long will it take? It will be repeated?

MR. EVERETT: Yes.

MR. NELSON: Mr. Ray, Mr. Ray, it might be a time to note it now that we have already committed to do the joint exercise in June of 1983 so all the dates that Vince is talking about lead up to that first joint exercise so all that will be tested in June of next year.

MR. RAY: Thank you.

(Slide)

MR. EVERETT: Our effort on public information -- we'll try to build up a peak about the time of our exercise in June. The public information program will include the annual program of brochures, media program which already is in place and has been in place for a number of years with DOE in which the press come and tour the facilities and get presentations given to them. A speaker's bureau which goes down and gives presentations and classes on a number of subjects and they'll also be giving them on emergency planning, the visitor's center, and during emergency operations we have the joint press center and the rumor control operations.

MR. MARK: You mentioned in many places to which phone calls might be directed that cited questions raised and probably you said but I missed it, I guess, where is the voice who says, there is radioactivity moving out to the East, the West or the South? Is that the plant manager and is he shielded from -- I don't mean he's shielded but he obviously can only handle a few phone calls. Where does that authoritative comment come from overriding excited concerns that B&W or -- you mentioned about 17 or maybe 20 different people who might be handling something or other but they don't know what they're handling.

MR. EVERETT: The information on what is occurring for example -- a release from the plant -- will go the press from the emergency public information director located at the joint information center at the headquarters building.

MR. MARK: And he will be in direct contact with the plant manager or something of that sort?

MR. EVERETT: That's correct. He is part -- his phone is on the dedicated phone system and he can contact the plant manager, recovery manager, states and counties and coordinate this release. What will happne in an information situation like that is that the recovery manager and the emergency operation facility public information person there at EOF -- he collects the data, the recovery manager makes sure it's accurate, that then goes to the Emergency Public Information director at the headquarters joint information center who then releases that to the public and any request for information that comes in through the supply system or the phone system will come into the public information center there at the headquarters building and the telephone operators will read the press releases. If they do not have the information, they will either get the information while the person stays on the phone or get a phone number to try to call them back later. So the single voice comes from that joint information center at headquarters.

MR. MARK: Thank you.

(Slide)

MR. EVERETT: The last couple of slides, I want to point out the advantages of the emergency preparedness programs for the Hanford reservation. The Hanford reservation has been operating nuclear plants since the early 1940's. There's a large pool of technical personnel and resources available to support us during emergencies. We have low population in our planning zone. It minimizes problems of evacuations. We have a local acceptance and understanding of nuclear operations which is very beneficial to our programs. We have a large number of people in the community who are directly related to the nuclear operations out here.

We have an active DOE emergency preparedness program that supply system coordinates with.

(Slide)

The advantages of the supply system that are unique is to point out that it's a nuclear oriented company and upper management is always aware of the problems or nuclear operations in planning for emergencies. They have a strong upper management support for safety. One of the first things that Mr. Ferguson asked for when he came on board was a status of where we were on emergency planning and that was very reinforcing to our program.

Our corporate offices are near the plants so we have a corporate support in operations that are quickly available. That's it.

MR. PLESSET: Well, thank you. I'm going to make an assumption, that the subcommittee is going to recommend that you come into the full committee and when you're going to do that, you're going to have to condense a day and a half into four hours.

Now, I'm going to give you a way of saving 34 minutes. I think in this section you need just one simple statement. First you have been actively developing an emergency plan. Second, you have no expectation of any difficulty of cooperation with local governmental authorities. You have a large amount of material in the handout. If anybody wants to know more, they'll have to ask you. Do you think that will do?

MR. EVERETT: That's fine with me.

MR. PLESSET: I think that will take one minute. I think the material you have is very good and should be made available to the full committee and yo: should be there to answer any questions regarding details. That's a way of -- it isn't that it isn't important. You have to do it anyway. This is a requirement on you and I think it's very good that you've been serious about it and it looks like you've done very well.

MR. EVERETT: Thank you.

MR. PLESSET: But you can't go into the details on these things. You have to do some severe condensing, okay? But I want to thank you for your presentation anyway. It's been good and Dr. Mark has learned quite a bit.

DR. MARK: Always.

MR. PLESSET: Okay, well, thanks again. One more comment. Mr. Ray?

MR. RAY: I feel compelled to endorse what Dr. Plesset has said. We have seen many emergency plans and I -- in my own case, this is the most comprehensive and most carefully thought out one that I've seen and I'd like to comment you for it.

DR. PLESSET: Yes, and we'll try to mention that to the full committee and that will help you. Mr. Ray made a very pertinent observation and it's true. I agree with it completely.

MR. EVERETT: Thank you. The next speaker will be Mr. Renberge- Deputy Director of Technology who will discuss geology and seismic issues.

MR. RENBERGER: The issues, part of this slide is at your request, the issues on seismology and geology have been resolved with the NRC staff.

(Slide)

The supplemental safety evaluation report was delayed while we pursued a review of a fault on the Southeast anticlimb of Gable Mountain. We demonstrated that that fault which was the nearest site fault, was not capable so, earlier a few months ago we had some issues. Now we have those issues resolved.

(Slide)

The topic today I will cover today in summary form will be the regional and site geology, the construction permit licensing basis, new information since the time of the construction permit and then the operating license, licensing basis.

(Slide)

On your site tour, the site is here in close proximity to the Columbia River. The tri-city areas are down here in the vicinity of the bend. You should have seen from the site the Saddle Mountains clearly, a high range of mountains across the Columbia River, possibly the Gable Mountains, a much lower range of hills here, the Rattlesnake Wallula alignment, Rattlesnake Mountain

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is a very large mountain to the Southwest of the site and this is a -- there's an alignment of hills along here, down the Wallula fault zone. There's faulting known to be down in here.

These other lines here are structures in the vicinity that are folds in the basalt that underlies the area.

(Slide)

Underneath the plant site, there are gravels about 60 feet deep that are in the age range of 10,000 years old, 10,000 to 15,000 years. These gravels came from a Missoula flood event which brought a large body of water through the region from an ice dam in the Montana area. Below that are very rock like cemented sands, silt and gravel down to a depth of about 400 feet with an age of actually 3 million to 10 million years. The below that are the basalt layers. Basalt flows that extrude in the region in the range of actually 10 to 25 million years ago and there are 25 major flows identified. These basalts are chemically different and they can be cored and identified so there's a good strategic or stratographic horizon to map.

MR. RAY: Mr. Renberger, perhaps I wasn't listening hard enough. Would you encompass the area with your light on the map under which the basalt is underlining?

MR. RENBERGER: The basalt underlies the whole region.

MR. RAY: The whole region.

MR. RENBERGER: Yes. And it is a predominant feature. For example, at these hills, it is very near the surface. At the site, under the plant, there is this very old cemented silt and gravels which also has strato-graphic horizons in it, identifiable by both reverse magnetism, you know, identifying the age by reverse magnetism and by radiographic or measuring it with the gamma radiation and so on.

MR. RAY: Would you encompass the area of the Hanford reservation on the map for me?

MR. RENBERGER: The Hanford reservation itself goes up to Rattlesnake Mountain, along the Columbia River crosses the Columbia River in the federal reservation in this area, comes back down this side here, so it's right in that area is the Hanford reservation.

MR. RAY: Thank you.

(Slide)

MR. RENBERGER: The construction permit for number two was issued in 1973 but there's been a lot of activity in the area from licensing standpoing since that time. We have two other plants in the vicinity of number two, number one and number four units were licensed in 1975 and in 1978 and in obtaining licenses, construction permits in those plants, additional work was done in the region. The techniques and methodologies and licensing criteria evolve with time as you know and so additional work was done and then finally we're at this present stage with the number two operating license review.

(Slide)

The construction permit licensing basis was used for all the facilities at Hanford in the late 60's and early 70's, based on the largest historical earthquake, intensity 7 that occurred near Walla Walla, Milton-Freewater, Oregon, Walla Walla, Washington, Milton-Freewater, Oregon and it occurred in 1936, about 80 kilometers from the site. The the exact structural association of that earthquake with a known structure or fault has not or was not determined at that time and it was assumed that that earthquake could have been associated with the aligment of the Rattlesnake Hills, Walula Gap fault zone, that was assumed that the Rattlesnake Mountains might be capable. For conservatism, the intensity was increased to eight and then the design basis for the plant of .25G, a zero period of acceleration was identified with the appropriate response spectrum.

(Slide)

Since -- in recent time now, in the past several years, there has been additional work associated with the basalt storage project, waste storage project at Hanford, the Skagit-Hanford plant citing, the supply systems own work in response to NRC questions. So there's a large amount of additional data obtained and of course, in this field, it will always be obtained; there's always someone looking in the field, drilling and so on.

(Slide)

Out of all this data, the analysis, the analysis, the interaction with the NRC has come the operating license, licensing basis. This operating license basis still rests upon the largest historical earthquake being that 1936 Milton-Freewater event, but in the past two years, we have assessed the magnitude, probable magnitude of that event, looking back at the instrumented measurements of that earthquake instead of just the reports, and it's been assessed as a magnitude 5-3/4 and the magnitude assessment as you know, is a more preferred licensing basis these days than an intensity basis, so we have done that.

The nearest capable fault has been identified as a central fault on Gable Mountain.

MR. RAY: Escuse me. Do I read from the diagram your statement that the magnitude 5-3/4 is considered equivalent to the intensity of 7?

MR. RENBERGER: I wouldn't say that you could find a correllation curve but by the separate techniques that evaluate intensity and that evaluate magnitude, yes.

MR. RAY: Well, in your earlier, in your CP stage, the intent for conservatism was to consider intensity 8.

MR. RENBERGER: And there were correlations that convert intensity to acceleration that were used to arrive at the .25G.

MR. RAY: Okay, and you're holding that--

MR. RENBERGER: We're holding that -- I'm saying here that for the operating license licensing basis, that same event still assessed at an intensity 7 -- there has been no change in that assessment of it --

MR. RAY: Yes, but the element of conservatism is what's concerning me.

MR. RENBERGER: All right, that will come later.

MR. RAY: Can you bring that out?

MR. RENBERGER: Okay, yes. All right.

MR. PLESSET: Actually, Mr. Ray has touched on a point that would be in the greatest interest to some of the committee members who are converted seismologists or physicists. There's nothing more enthusiastic than a recent convert. So, you have to be prepared for that and questions that they may have. Among questions that you will get are questions that nobody can answer but you mustn't be too surprised.

MR. RENBERGER: I was afraid of that.

DR. PLESSET: What's the return period?

MR. RENBERGER: Pardon me?

DR. PLESSET: What's the return period?

MR. RENBERGER: We do have an estimate of that for this plant.

DR. PLESSET: Okay, and you can defend it?

MR. RENBERGER: We have an estimate of it for this plant. I wouldn't defend it strongly but say, but we can describe the rationale for it.

DR. PLESSET: Okay, I think that the conservatisms and your basis for it are the really important part of your presentations, rather than a lot of details except that you have to get into those to answer the question properly. I'm trying to be helpful, that's all. I'm not being critical.

MR. RENBERGER: Well, let me jump down to the safe shutdown earthquake structure now and answer your question on conservatism.

The Rattlesnake-Wallula alignment still is the most prominent structure considered to be capable of faulting, but in the year since the construction permit there have been techniques developed for estimating magnitudes on structures and faults based on fault length, fault area, and so on, so now on this basis, both the NRC Staff and our consultant have evaluated what rattle-- what this Rattlesnake Mountain - Wallula alignment really is capable of and it has been assessed at a magnitude 6.5 and that magnitude still is -- and the resulting site acceleration is still within the .25G design, so the actual, the translation of this earthquake at Milton-Freewater up along this is no longer done quite that way because of new methodologies and there's one other methodology I need to cover with respect to that and that is, there is some controversy about whether that 1936 earthquake occurred on an extension of that Wallula Fault Zone or on a height fault that trends this way to the Northeast and because the Staff, the NRC Staff was not convinced that it could be pinned to either of those structures, they asked us to develp a site specific response spectrum based on that earthquake. It was conservatively done at 6.1 but develop a site specific response spectrum that assumed a random earthquake occurred somewhere in the region on a structure not identified or maybe not on a structure and develop a site specific response spectrum based on that earthquake occurring about 15, 16 kilometers away, so these methodologies in the licensing world -- this methodology is comparable to what has been used on the review of operating plants, re-reviews. Develop the random earthquake response spectrum. So the reason this slide is entitled to OL licensing basis is methodologies have changed some but the basic facts haven't changed. The 1936 earthquake is still there. It's still the one that occurred. As I started to say, there has been in the past two years, a capable fault that offsets those 10,000 year old sediments on Gable Mountain. It's been assessed, has a capability of a magnitude 5. It does not, the resulting impact on the plant does not reach the .25 GE design basis.

In addition, small magnitude earthquakes have been assessed. At the time of the construction permit it was known that there were micro-earthquakes occurring in the region in little swarms, generally associated with the boundaries of irrigated regions, newly irrigated lands across the Columbia River, so in this licensing phase, we have looked at small magnitude earthquakes in reasonable proximity to the site, looked at the ground motion from those, assessed the free field ground motion and then assessed the impact on the plant and again found that the plant design basis is adequate to handle the small magnitude earthquakes.

Now, for the exceedence or recurrence interval.

Because of the large number of structures in the region that have faults, but the fact that the region has low seismicity, it's not a California situation. We commissioned a probablistic risk analysis or exposure analysis for seismic purposes, to look at all of these structures and say what if you have an earthquake from a strike, strike slip-fault or a reverse fault, what size earthquake could it be based on a geology using the accepted correlations, what would that earthquake result in in a seismic or ground acceleration at the site and then look at the overall exposure of the sight to all potential sources and in our theory the probablistic assessment should provide over some long time, many years, some perspective as to how important new data is to you. How does some new data affect the seismic exposure.

So what we found in the study is the expected recurrence interval, the expected annual probability of exceeding the .25G design, is 1.1 X 10^{-4} or about one in ten thousand years recurrence interval for the safe shut down earthquake. In the licensing submittals, there is also a curve that shows the recurrence interval for other size earthquakes. I can imagine that at the full committee meeting we may talk about that curve. Or today, if you like.

DR. PLESSET: One way of looking at what you might encounter is if you had an earthquake, say 10^{-4} probability, annual probability, which was way, 0.35G for example, you've got a core melt. This makes that core melt too probable. I may not have expressed it, but you see what I'm getting at?

MR. RENBERGER: Yes.

DR. PLESSET: This is something you have to be able to deal with. We have to have the probability of a core melt, less than 10^{-4}.

MR. RENBERGER: I can't help but throw this slide up. It's back up and you don't have it there.

(Slide)

But, it deals with what you're talking about and this is the overall result from the exposure analysis and the .25G design is here and you read the 1.1 approximately times 10^{-4}. Considering all the sources from all these structures, now if you hypothesize a larger earthquake of whatever size it takes to make a core melt, we don't know. But if you want to guess and run down this curve, you can find the probability of exceeding higher G values, or the recurrence interval for higher G values. Now, a fact with this curve, which is in our licensing submittal, is that the slope of this top line is strongly driven by the assumption that a southeast anti-climb from Gable Mountain is capable. It's the closest to the site, and earthquakes, it was assumed 90% probability of being capable in the exposure analysis, so earthquakes that close to the site really control the site exposure, this top curve. As you can see, there's the exposure from that. Here's the exposure from Rattlesnake-Wallula, the real large structure in the Region, so being so close it controlled a study, the output. Now, we went in and drilled core holes over that fault, found reverse magnetism in a layer of gravel over that fault that was not disturbed and showed that it's not capable, but we did not go back and redo this analysis, but the real truth is that curve now, from all sources would be down in this range and the change slope really helps in terms of the probability of the higher G values.

DR. PLESSET: Well, that's very helpful and I think you should have that available, too, when you come to the full committee.

MR. RAY: I'd put the new curve in.

MR. RENBERGER: Okay. But I'm not a geologist-seismolgist so I'm a little hesitant to throw this up here but I do understand why we did it, what it means and the significance of it.

MR. RAY: I don't mean to use the diagram, use the diagram, but correct the curve, if you have good scientific basis for it.

MR. RENBERGER: Well, we have mixed feelings about that. We're not going to stand behind this as the real answer, either, and it's not really accepted in the licensing arena. It's interesting and it helps us all gain a perspective and periodically, we would probably update it, but we haven't chosen to update it for this particular time, just because of that. It isn't something that you can sit on that strongly, but it's useful.

MR. RAY: You can sit on it in terms of validity of evidence in a court of law in a suit, for instance, but from the viewpoint of technical thinking, it seems to me it's a plus value for you and if you get into a discussion in detail, I would have that curve available and I would have it corrected, updated, as a point of persuasion, if nothing else. I'm having trouble because of age and reading the axis, the values on the axis of ordinates.

MR. EBERSOLE: Let me comment on that. I see something that I think you see, because I've got my tri-focals on.

MR. RENBERGER: I knew I shouldn't have put this up.

MR. EBERSOLE: What is says to me is that in the 40 year life of the plant, you've got something like a 10^{-3}. Am I reading this correctly?

MR. RENBERGER: That's correct.

MR. EBERSOLE: Chance of having an exceedence type earthquake, is that correct?

MR. RENBERGER: On that top curve, that's correct. Or 10^{-4} if it's down in here.

MR. EBERSOLE: Now, that's going to automatically throw us into a horrendously detailed investigation of the seismic margins you have in your equipment, including the margins in a very expensive equipment where it costs a lot to make it better, and the $2 type items where you could buy at large margins, the whole spectrum of margins.

MR. RENBERGER: If you sit with that top curve.

MR. EBERSOLE: Yes, right. So, that's going to provoke an awful lot of further conversation unless you can lower it.

MR. RENBERGER: All right, I got the point.

DR. PLESSET: I also would suggest if you might have available to you at the full committee meeting, the experts in this field that you had to work with you.

MR. NELSON: The experts are available.

MR. RENBERGER: They're available and here today if you wished.

DR. PLESSET: Because they might need to enter the discussion.

MR. RENBERGER: We just haven't authorized the spending of the money that it takes to do that, to lower that curve.

MR. RAY: It's your application.

MR. RENBERGER: I know.

MR. EBERSOLE: Do you have a detailed study of the so-called seismic safety margins across the full span of equipment that are necessary to shut the station down?

MR. RENBERGER: No, we do not.

MR. EBERSOLE: Well, you might find, you know, that there's a few cheap items that are on the border line of being barely proficient.

MR. RAY: At the risk of using two more minutes of the precious time that Dr. Plesset is trying to conserve and I'm sympathetic, I'm not a recent convert to the seismology that he referred to earlier, but I would like you to take two minutes to summarize the margin of conservatism that you have. Now, you went through quite a detail here. I have the impression that you're going from a 5-3/4 to a 6.1 magnitude. You're not tying it down to any specific structure and you're bringing the possible source of a disturbance in closer to the site. Is this a real measure? Does this encompass the elements of conservatism that you've --

MR. RENBERGER: This is not our choice to do that. That's a methodology that the NRC uses now and they ask us to do that. Our consultants believe that earthquakes occur on structures, on faults and that a random earthquake in the region is not really something that should be used as a basis --

MR. RAY: It's a fantasy.

MR. RENBERGER: So we don't stand behind that, but we were asked to do that as a test, and we understand the reason for it, a test of what if, what if there is -- how does your plant stand up to that earthquake closer to the site. We understand that.

MR. RAY: Now, you haven't left in my mind a clear picture of the degree of conservatism that you have in your design. Would you in layman's terms try to convey that to me?

MR. RENBERGER: I cannot directly, in layman's terms I guess, describe the degree of conservatism in the design. The techniques used in the design, I would have to ask Dr. Bedrosian to just briefly summarize the method of design for this plant compared to, you know, in terms of the techniques used and how that results in margins.

MR. AULUCK: Dr. Plesset, the Staff would like to make comment on that.

DR. PLESSET: Beg your pardon?

MR. AULUCK: The Staff would like to make comment.

DR. PLESSET: I think that would be helpful if we, if you let him have some of your time.

MR. KIMBALL: Jeff Kimball, I'm a seismologist with NRC Staff. The 6.1 or the 5-3/4 are two different -- one is an ML and one is an MS, is the largest earthquake in the tectonic province which has not been associated with the structure, definitively associated with the structure. And it's typical with Central and Eastern U.S. sites, we view this as the tectonic province earthquake. The earthquake which has some likelihood to occur anywhere in the province. I don't believe in random earthquakes either, but there is an unknown that you don't know the structures that exist and that's the way of dealing with that. And that's the conservatism there.

In terms of the raw, the conservatism of the CP was to just to increase the intensity by one unit and at this stage, it's to assess the same structure in terms of magnitude and the 6.5 is larger than any other earthquake that has occurred in the tectonic province in historic times.

DR. PLESSET: I think we understand that and that's a way of indicating a basic conservatism which is built into the review, but well --

MR. RENBERGER: Well, let's have DR. Bedrosian address the design.

DR. PLESSET: All right, do you want to come up and use the microphone, Dr. Bedrossian?

DR. BEDROSSIAN: Yes. I was asked to briefly describe the conservatism available in the original design of the plant for the seismic events.

I think the original design is of the early 1970 vintage and at that time, very stringent requirements were placed, and limitations on the design because of the state of the art at the time and the knowledge at the time, so that the resulting design was in our opinion quite conservative. The way a plant is normally analyzed is that you develop a model and at the time a so-called lump mass model was used. One has to allow for interaction between the structure and the soil and at the time, springs and dashboards were used to model such interaction of things. A careful review by NRC imposed additional constraints at the time. It suggested that very stringent limitations on the damping values in the dashboards representing the interactive effects, be imposed -- the maximum damping value was set at about 10% of the time. Since then, the know-how has developed and the methods which are used to perform, to evaluate such structure interaction effects are mostly based on finite elements and/or equivalent methods of analysis and if this is implemented and the limitation on damping and the conservatism of the lump spring mass formulation for interactive effects are deleted, one could see that the significant conservatism was built in the plant. We had the chance to do some finite element analysis or implement them later, and the comparison between the responses obtained from the original lump mass analysis and the resulting values which were used in design of structures and equipment and a more recent finite element analysis are quite reflective of this significant conservatism.

DR. PLESSET: Thank you.

MR. RENBERGER: I have one more slide.

DR. PLESSET: All right.

(Slide)

MR. RENBERGER: In conclusion, the original safe shut down earthquake has been confirmed, is adequate and conservative, by the techniques that I've described in some details and there are no open items, open issues with the NRC Staff.

DR. PLESSET: Fine, well very good. Thank you.

MR. RENBERGER: The next speaker will be Jerry Dusty Rhoads who will talk about equipment qualification. Jerry is the program manager for equipment qualification on the supply system staff.

MR. RHOADS: We'll go right into the first slide.

(Slide)

I'm going to try to make this my presentation brief, because I know there were a number of questions raised earlier that I'd like to provide time for.

Primarily the objectives of our program are to confirm the WNP-2's safety related equipment can perform a safety function under all postulated acts of incidents and conditions, where documentation is deficient to establish this confirmation, take the necessary corrective action.

We also want to address and meet the reasonable and technically justifiable concerns raised by the NRC in our recent activities and to meet these concerns with aggressive programs. It minimizes the impact to our plant completion. And also, to establish the resource and expertise within the supply system to carry on the work throughout the plant life.

(Slide)

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The basic environmental requirements for the WNP-2 plant are to meet the requirements of NUREG 0588 four months prior to full power operation and licensing of the plant.

In terms of the licensing process, all nine qualified items must be dispositioned by test or analysis or other corrective action, by the NRC audit date. I'll get into that date later.

All safety related electrical and mechanical equipment shall also be qualified to the seismic and hydro-dynamic loads by fuel load with 85% of this equipment qualified and installed by the time we have the audit with the NRC.

(Slide)

Plant history, in the upper left-hand corner, you see the dates that are PSAR, construction permit, and applicable IEEE standards for a licensing base. You also see in the lower left-hand corner, when we procured most of our equipment, placed orders and had deliveries. You can see on the right hand upper side the FSAR docket period and the intensity period in terms of new guidance and information for the NRC for us to address, in terms of NUREG o737 -- when the TMI II accident occurred, IEB 79 01B, and other regulatory documents provided us information.

In the lower right-hand side, you see where we started the equipment qualification upgrade program. It was in late 1979 we chose to centralize the organization to address essentially what was being provided to the operating reactors. We didn't wait for the NRC to notify us to get hot out (ph) because we're an NTOL and looking at this concerns (ph). We took action when we -- on an upgrade program when the concerns were raised to the operating reactors.

(Slide)

I'd like to talk basically in terms of what constituted an equipment qualification program. The first portion of this is establishing the evaluation criteria. Our first review of NUREG 0588 gave us some concerns. We disagreed with some of the elements and we sent comments to the NRC on some of these points.

We also established that we needed to know more about this issue technically and so through the electrical power research institute, we commissioned some studies to be done as an industry group. I've listed them there. They've provided us some very good fundamental information by which we could continue our discussions with the staff and also refine our program in the areas of critical -- in the critical areas that really needed a good looking at or relooking at.

We also participated in AIF workshops to address areas of disagreement and to come up with alternate methods of meeting the Staff's concern and also in trying to implement our input into the rulemaking processes, we are also part of the nuclear utility group.

(Slide)

The second portion of the program and this is highlighted in NUREG 0588, half of NUREG 0588 deals with defining the envirnment. The other half deals within what is the criteria that you evaluate your equipment to in terms of methodology.

(Slide)

Establishing the accident environment criteria, we re-performed radiation studies for our plant. We re-performed high energy line breaks for outside of containment. We have re-performed LOCA and MSLB, main steamline breaks inside containment. We've also looked at this effects of a LOCA and main steamline break to the secondary containment and we've looked at flooding and have completed all of these re-analysis except for the flooding issue outside containment which is nearly done. The original design base was a generic specification from our NSSS supplier. With very few exceptions, that general generic specification was adequate. There are a few cases where there's a slight higher peak or a little bit longer duration.

The third element of our program is establishing the basis, and by that I mean the equipment that we look at and to try to pull this equipment into a definitive list that brought all of the elements of equipment qualification together.

(Slide)

This information was available. It was scattered throughout the documentation but it wasn't centralized. This was one of the harder areas of our program, to pull all of this information together in a centralized list, including the tag numbers, the actual tag numbers of the equipment in the plant, the manufacturer model number, what actual safety function it performs, the plant location, exactly where it is in the plant and how long does it really have to operate during an accident and to what accidents does it have to perate in.

Within this, finding backup documentation to the certificate of conformances that were generally a part of our basic documentation requirements from our vendors was an activity that has been ongoing for the last two years and we have been everywhere trying to find and to establish good credible back-up documentation to certificate of conformances. And to A/E files, vendor contacts and utility sharing have been the success task for us in finding a great deal of the documentation.

(Slide)

The fourth point of the program is to actually perform the evaluation to the documentation and to the criteria. We have as I say, centralized this function, the supply system, it's staffed with 8 engineers working directly for me and a couple of record analysts which are a tremendous support in terms of documentation. We are supplemented where our program is needed by a consultant working under direction from us. I have listed some of the consultant support and I believe the on-site number is now close to 8 in terms of consultant support.

(Slide)

The final portion of the program is when we find document deficiencies where we can't establish that the equipment was sufficiently tested or analyzed, and the documentation, the back-up documentation is not available or somehow as misplaced or lost and we take corrective action. We have direct contracts with two test laboratories, have listed them. We are cost sharing with other BWR's of the WNP-2 vintage in a cost sharing group which we call "Equate" and we're also joining other selected cost sharing programs in the industry that are not out of BWR areas but an instrument group, Rosemont and Foxburrough transmitters were a part of that group. We're part of an ITT General Controls cost sharing group and we're very intense in terms of trying to cost share this issue, cost share generating this additional documentation with other utilities, to minimize the cost of the program.

(Slide)

The program comes together with a great deal of interaction from a lot of different sources. In the seismic area, the piping analysis hydrodynamic loads, document retrievable lead to being able to perform the seismic evaluation.

On the environmental side, the various environmental studies and an evaluation review to those lead to a recommendation on whether or not the equipment is qualified or there's sufficient documentation to qualify it. Those lead to initiating a recommendation to our project engineering staff. They assess the recommendation for corrective action in terms of plant impact, what is it going to do in terms of completing this plant. If I make a recommendation to replace, what effect is that going to have on us.

(Slide)

Upon concurrence with those recommendations we initiate the requalification activity. In the center line of our program is the complete acceptance of the qualification program of each piece of equipment on our plant and I've listed some of the licensing elements which I'll go into more detail.

(Slide)

The seismic qualification schedule for both mechanical and electrical equipment will be performed in November of 1982. We've established that with the Staff. We will submit a report to them six weeks prior for them to select the equipment.

We're presently at an 85% qualified or an 85% level of qualification for the seismic element of our program. The schedule shows completion of all Class 1E and safety related mechnical equipment by fuel load and we think we can make that.

(Slide)

The environmental qualification schedule was our first submittal -- was provided to the staff in January 15th, 1982, as input to the SCR process (ph). We have continued working on our program and have established about an 85% level of qualified equipment, for equipment located in a harsh environment.

Our second submittal is scheduled about this time next week to leave our house to go to the staff and it will include responses to the NRC's first review, completion of the confirmatory analysis that I've talked about, corrective action plans for equipment with deficient documentation status. I'll also include our justification that WNP-2 can be operated safely pending completion of corrective action. This justification for interim operation was performed in accordance with the criteria given in the most recent draft of the present rule on environmental qualifications.

(Slide)

We have some corrective action programs under way. They include test programs for various pieces of equipment that I've listed here. These programs are under way and we are active on them.

Replacement actions. We have elected to replace some pieces of equipment. I might say for the majority of these we felt that the documentation was deficient. We didn't know if the equipment was but it was in our opinion a better course of action to take a replacement action and a restesting action so we chose to do that. We've upgraded NAMCO limits which is to newer nuclear grade models, the same with ASCO Solenoid Valves and a steam tunnel and inside containment.

For our electrical penetration boxes inside containment we are replacing the supply terminal blocks with another terminal block by another company which we tested, completed those tests in December, the NRC monitored those tests with us and gave us a favorable report in terms of that test program.

We're also replacing some Bailey transmitters with newer transmitters from another manufacturer, that are qualified.

(Slide)

In the area of mild environmental qualification, which is outside the harsh area that I've been talking about recently, we have been of the opinion that a good maintenance and surveillance program was what was necessary and what should be implemented for this equipment to address environmental qualification concerns.

The NRC in their rulemaking process has recently published this guideline that it is primarily a QA requirement and not necessarily a qualification requirement and they've also stated that a good maintenance and surveillance program meeting Appendix B and Reg Guide 1.33 is sufficient and we comply. And we are in agreement with that position.

(Slide)

In conclusion, 85% of our items are seismically qualified. Our October submittal to the staff will provide the details to them. We have all -- we will have all equipment seismically qualified by fuel load. 80% of our 1E items in a harsh environment are qualified and I'm told this morning that number is up to 83. They'll be detailed in the September submittal to the NRC. The remaining 20% of the 1E items in a harsh environment are scheduled for qualification. This will be detailed in our report and those are the options that will be detailed in terms of our activities for that.

We have completed our justification for interim operation and we will work with the staff to have that approved prior to fuel load.

And for the items that are in a harsh environment that are outside of this group of equipment items that are required for the justification for interim operation the other equipment will be qualified in accordance with the conditions, recommendations for November 30th, 1985.

That concludes my presentation and I'm open for questions.

DR. PLESSET: Thank you, Mr. Rhoads.

Let me make a general comment. I think all of this material should be available to the full committee but I think the presentation you gave could be very brief.

Jesse, would you like --

MR. EBERSOLE: I'd just like to ask a few questions.

DR. PLESSET: I think Jerry wanted to first and then we'll turn to you.

MR. RAY: Only a general comment. The question of a qualification of equipment is a rats nest of possible areas of disagreement and wheel spinning and I'm impressed that you people have gone about this with a very workmanlike attitude and you're facing up to the problems.

MR. RHOADS: Thank you.

MR. RAY: I think it's very direct and commendable.

DR. PLESSET: Jesse?

MR. EBERSOLE: Yes. I'd just like to ask about some route considerations before you start your qualification of program. As you know, the defense in depth concept requires that you meet accident conditions, whatever is an accident, on the thesis that you have the privilege of mitigating the accident, considering a random failure in one of two competent channels. Now, I said random, not consequential. Having said that, when you looked at the severe conditions associated with a pipe break or whatever, is the basis of your qualification program to ensure that after the accident has occurred and having included the damage to perhaps some mitigating equipment, do I have two competent mitigating systems .

available within which, one of which I can suffer a random failure?

MR. RHOADS: The brief answer to your question is no.

MR. EBERSOLE: Well now, I think we should list those cases where you have a single functional operative mitigating system left after an accident, because we're going to have to consider the potential of that experiencing the random failure, thus leaving you high and dry.

MR. RHOADS: Okay, the equipment is qualified to the environment that it will see. In otherwords, we perform tests to the equipment for the environment that it will see and which it must function in, so if we have a high energy line break and the equipment is exposed to the high energy line break, we run a test to those conditions to a type test, to verify that the equipment can work in that environment. I do not have two other trains outside that.

MR. EBERSOLE: No no no, I didn't say two others, as long as you prove survivability of the one that you looked at.

MR. RHOADS: Yes, we are doing that.

MR. EBERSOLE: So my statement is still correct.

MR. RHOADS: So my answer is yes.

MR. EBERSOLE: Yes, your answer is the reverse of what you said.

MR. RHOADS: Okay, I misunderstood your questions.

MR. EBERSOLE: That you still have survived, your equipment has survived such that you have the privilege of a random failure after the accident.

MR. RHOADS: Assuming that I still have equipment operable --

MR. EBERSOLE: Well, that's what you're supposed to prove.

MR. RHOADS: Because I'm verifying it through my testing.

MR. EBERSOLE: Yes.

MR. RHOADS: Yes.

MR. EBERSOLE: Isn't that the object of your test to show that it's functional and thus give you the privilege of a random failure subsequent to the accident.

MR. RHOADS: Yes.

MR. EBERSOLE: And isn't the basis of your whole program simply that, to show that you have mitigating competence in two channels?

MR. RHOADS: Yes.

MR. EBERSOLE: And you do have that everywhere.

MR. RHOADS: Yes.

MR. EBERSOLE: Watch it because there's places that get tough.

MR. RHOADS: I know it gets tough. There's a -- I will have that is what I'm saying. We have a justification for interim operation which doesn't assume that. All right, so a justification for interim operation will show that we have a single path to achieve cold shut down.

MR. EBERSOLE: Oh, an interim operation.

MR. RHOADS: Yes.

MR. EBERSOLE: You're going to have some cases where you have only one functional track for mitigation after an accident.

MR. RHOADS: Right, right, but in accordance with the commission schedule, we will be, we will demonstrate the qualification for the full range of equipment by November 30th, 1985.

MR. EBERSOLE: Are there many cases like that where you have only one functional track after an accident? Are there half a dozen or a hundred or any feel for this?

MR. RHOADS: No, I don't. What we have just completed, the justification for interim operation, it shows that there are some pieces of equipment that we're going to have to establish qualifications documentation for.

MR. EBERSOLE: Okay, but you're aiming for that?

MR. RHOADS: Yes.

MR. EBERSOLE: Right, so, you're going for the goal of having the privilege of a random failure after the accident, is that correct?

MR. RHOADS: We're going for that goal, yes. We won't stop our program until that goal is achieved.

MR. EBERSOLE: All right, now then, you have a once out of two twice system, a GE system that incorporates both redundancy and coincidence in four channels. Do you have any cases -- this is in essence a redundant system which is paired. Do you have any cases of destruction of impulse lines associated with an accident or being an original failure which leaves you hung without redundancy to mitigate the consequence of such an impulse line failure?

MR. RHOADS: We've evaluated high energy line breaks from various pipe sources.

MR. EBERSOLE: So, what an impulse line is, whether it's high energy or not, it's high pressured.

MR. RHOADS: Are you talking about instrument lines?

MR. EBERSOLE: Right.

MR. RHOADS: Okay. That particular study was not a part of our environmental development criteria. The results of high energy line breaks is the more limiting accident in terms of pressure, temperature and effected area. And in that program, we did look at the pipe whip where the impact would be, what it would wipe out, what the environmental effect in a neighboring room would be in terms of temperature pressure and humidity and provided that as the qualification basis by which we required our tests to be.

MR. EBERSOLE: So you don't really consider this impulse line business within your scope of general environmental qualification? That's another area of work?

MR. RHOADS: That to me is a systems interaction problem.

MR. EBERSOLE: That's another question.

MR. NELSON: Mr. Ebersole?

MR. EBERSOLE: Yes.

MR. NELSON: Can we answer your question? There was some confusion in my own mind.

MR. EBERSOLE: In the general context -- yes, go ahead.

MR. NELSON: In the justification for interim operation versus post-1985?

MR. EBERSOLE: In the context of environmental qualifications. I think you did.

MR. NELSON: I sense some confusion.

MR. EBERSOLE: Yes, in that context. The other system interaction aspect, I guess we haven't gotten straightened out yet, about the impulse line failures and so forth, so we'll wait for another time for that.

MR. EBERSOLE: Holding to the environmental qualification area.

MR. RHOADS: I answered your first question thinking a justification for interim operations in terms of redundancy of channels availability.

MR. EBERSOLE: Thank you.

MR. RHOADS: But the program will continue to get duel redundancy.

MR. EBERSOLE: I guess it would be nice to package the cases where we will be running in a single channel configuration for this interim interval.

MR. NELSON: Just for the interim part of it.

MR. EBERSOLE: Just package it up. Yes, right.

DR. PLESSET: I think Dr. Lipinski has a comment or question.

DR. LIPINSKI: On your seismic qualification, are you using a cut-off frequency to determine qualifications such as 33 cycles as an upper limit?

MR. RHOADS: Only in areas where we do not have hydrodynamic loads do we use the 33 cut off point.

DR. LIPINSKI: I'm particularly thinking of your relays that are spring mass systems that have characteristic resonant frequencies, whether you only look at those up to 33 cycles and everything is fine so you say they're qualified, whereas they may resonate at 40 cycles.

MR. RHOADS: It is true that a spring mass system such as a relay could have a higher frequency content, if that relay's location is an area of our plant that would have that frequency counted as part of it's input, then the relay would be evaluated up to the frequency content of the input and for hydrodynamic loads it goes much higher than 33 cycles. If that relay is located in our plant area where it's only going to be subject to the seismic condition, the energy input from the seismic condition is focused in the 1 to 33 Hertz region.

DR. LIPINSKI: That's what I thought but the energies actually go beyond 33. They're negligible and usually what you're getting from your plant analysis terminates at 33 but there are energies beyond 33 cycles but they're lower in magnitude and theoretically a spring mass system requires very little energy to excite it at it's resonant frequency.

MR. RHOADS: I understand what you're saying.

DR. LIPINSKI: The fact that your analysis is up to 33 and it stops there and if you take that at face value and say my equipment is qualified, because you told me there's nothing beyond 33, that's not true.

MR. RHOADS: Then our opinion is it's nothing of significance beyond 33.

DR. LIPINSKI: Okay, but the NRC staff in setting these qualifications, divorced the question of the seismic issue until a later date, so that you're now in this period where you're now trying to make your decision without their guidance in terms of the final position on seismic qualification of Class 1E.

MR. RHOADS: We have been very involved with following the course of action for the seismic qualification review team over the last three or four years and we have trimmed up, we have aligned our program to be in conformance with that team's requirements.

We believe that the rulemaking process will confirm our program rather than modify it.

MR. RAY: I'd like to comment to the staff that I think Dr. Lipinski's comment is of significance in the Staff's work for the seismic requirements for qualfication and it's a generic situation that is beyond application just as planned, and I think in their present thinking they should have this cranked in, and clear up the situation and what is forthcoming on seismic and that message that you'll back.

MR. SCHWENSEN: Yes, I recall this discussion came up I believe at the Perry application also.

MR. RAY: Wolf Creek and several of them.

DR. PLESSET: Any other comment? I guess not. Thank you, Mr. Rhoads.

MR. RHOADS: Thank you.

Our next speaker is Roger Corcoran. Roger is the operations manager of the WNP-2. He has a B.S. degree in electrical engineering. He's got over 16 years in commercial nuclear reactor experience.

MR. CORCORAN: My name is Roger Corcoran. I'm the plant operations manager. I would like to cover several topics this morning, as listed on the slide including control of human factors, term habitability, decay heat removal and emergency operating procedures.

(Slide)

Briefly I'd like to reorient those of you who were on the tour yesterday of the plant site. The photograph on the left shows the plant lay out. Briefly, we toured the reactor building including the lower elevations where the emergency core cooling systems were located and the refueling floor and some of the other levels of the building where the drywell and the wetwell were accessed. We toured the control room which is located almost in the top elevation of rad waste control building. We visited the diesel generator building which contains emergency on-site source of power. The full chart is shown behind the turbine building, this photograph over here. Our ultimate heat sink, stand-by service water system is shown by the spray ponds over here (ph) which are off the picture and the cooling tower is located in this vicinity.

(Slide)

The first topic is control room habitability.

The main control room is designed to ensure habitability through all the normal and abnormal operating conditions.

We have portable breathing apparatus and five days worth of food, water and other supplies available in the control room.

We assure habitability by the following features:

(Slide)

We have 2 HVAC systems which are operated from the control room, each delivering at 21,000 CFM of recirculated air and 1,000 CFM of intake air. A full path for that is to bring in primary outside air, 1000 CFM, pass through the air handling unit and pass through the control room, recirculating 21,000 CFM of air from the control room back to the air handling unit. And we exhaust 1000 CFM of air, so if we take in 1000 and we exhaust 1000 we maintain an unpressurized condition. Now, if we maintain adequate temperature environment of the control room by supplying chilled water systems to the air handling unit, we have two chilled water systems, a rad waste building chilled water system which is backed up by control room chilled water system.

All required components are redundant, in the seismic category 1 of class 1E power. Adequate shielding protects the operators from radiation streaming. The thickness of the control room walls are about two feet thick and when coupled with the thickness of the turbine building walls or reactor building walls which vary from two to four feet thickness, we have plenty of concrete shielding. And the control room doors are designed to protect us against a steamline pipe break in the turbine building. The doors are designed for I believe greater than 3 pounds per square inch blast pressure which is greater than what we would have if we had a break in the turbine building in the steam line.

(Slide)

MR. MATHIS: Can you completely isolate the control room?

MR. CORCORAN: Yes, we can, and I'll discuss in a moment what mode -- what takes place in that mode.

MR. MATHIS: Okay, I'll wait.

MR. CORCORAN: Now, I'd like to discuss two significant modes that we, we may cover, that we may have that will allow us to maintain habitability in the control room. One is the loss of cooling in an accident situation. In this event, what happens is the local fresh air intake is isolated, either of the remote areas intakes are opened, supplying air through the emergency filter unit. Now, the emergency filter unit is placed in the pressurized mode of operation in this case, so we bring in 1000 CFM of air, pass it through the emergency filter unit and we do not exhaust. The exhaust is closed off, thereby pressurizing the control room, and minimizing the infiltration.

Now, if higher radiation is detected in one of the remote area intakes, then this is closed off. There is double valve isolation in both of these. We only need one remote air intake available.

Now, the 30 day dose assessment --

MR. RAY: I presume you have good separation between them?

MR. CORCORAN: We have physical separation between the remote area intakes.

MR. RAY: Are they on opposite sides of the plant?

MR. CORCORAN: They're on opposite quadrants of the site, yes. Northwest and Southeast.

MR. EBERSOLE: Did you say opposite quadrants? So that gets away from the wind blowing --

MR. CORCORAN: One is located Northwest area and so the other one is Southeast.

MR. EBERSOLE: Okay. Have you taken a look at your neighbors down the road, the FFTF in the context of whether their emissions might be worse than your own when they have trouble?

MR. CORCORAN: Yes, the FFTF analysis has been considered. There is one case where the sodium oxide emissions could cause a problem, however, because of the duration of time between the release at FFTF and the length of time to arrive at number 2, we can take precautionary measures in the control room, but we don't automatically protect against this. It's a communication situation.

MR. EBERSOLE: What about the radiation release? Is that less than you would expect?

MR. CORCORAN: The radiation release has also been analyzed and found out to be a problem.

MR. EBERSOLE: Is it worse than your own LOCA?

MR.CORCORAN: I believe it's less than our LOCA situation.

MR. EBERSOLE: Oh, less than your own LOCA.

MR. CORCORAN: I believe it is.

MR. EBERSOLE: I see. Thank you.

(Slide)

MR. CORCORAN: The second condition I'd like to discuss is the hazardous chemical release in the event of a break in the fluoridation system located in this earth water pump house. We have redundant chlorine detectors located in the pump and intake header, this location (ph). In the event the chlorine exceeds the lengths of at least 5 parts per million, we will have a total isolation of all intakes.

Emergency filter units will go on a recirculation mode rather than a pressurization mode. The exhaust will be closed off. The control room will be under recirculation mode condition in this event.

Now, the emergency filter units have capability to remove the chlorine in the air. And, the conclusion is that the leakage will infiltrate the control room, however, in the analysis, the analysis shows it low enough such that we maintain habitability and we do clean up the chlorine that may enter prior to the isolation of the lines.

MR. RAY: Would you help me in my ignorance? What's the source you consider for chlorine?

MR. CORCORAN: The source for the chlorine would be a break of a liquid, liquid chlorination system the surf water pump house, the 2000 pound liquid chlorine cylinder.

In conclusion, the response of the control room habitability systems -- the response to the chlorine habitability systems is fully automatic to any of these events which I've just described. We can maintain habitability.

DR. PLESSET: How long can you operate in the recirculating mode?

MR. CORCORAN: We can operate for extensive periods of time in recirculation mode with the air handling units and the emergency filter units.

DR. PLESSET: Is that a day, an hour?

MR. CORCORAN: No, that's extensive. That's days, that's weeks.

DR. PLESSET: Many days.

MR. CORCORAN: Many days, that's correct.

DR. PLESSET: What's the limiting factor in that? Why can't you do it forever? What limits it?

MR. CORCORAN: What is the limiting factor for operation for extensive period of time?

MR. BOUCHAY: I think we don't know. We'll have to get --

DR. PLESSET: Okay, that's reasonable.

MR. BOUCHAY: We'll get the answer to you on that.

DR. PLESSET: All right.

MR. CORCORAN: The second topic invòlves a control of human factors. During the 1970's, the supply system recognized that improvements were required in our control room design, to enhance safe operation. In otherwords to improve the operator machine interface.

(Slide)

Following Three Mile Island, the NRC issued various guides in performing control room reviews and as a result of that, the G.E. Owner's Group formed a generic program to meet thėse NRC requirements.

At number two, we decided to go into a dual approach with human factors. We set up an in-house review program which was a task force, in 1980, which would provide early definition of hardware changes and provide coordination of control room changes. Simultaneously with this, the BWR owner's group formed an industry wide committee which prepared acceptable generic programming. Utility people were trained, human factor specialists were used, General Electric was involved in an attempt to implement this generic program. Several control rooms were reviewed after training and we provided people to this generic control room review program.

Later on in our program, we will be having the owner's group come in and provide an independent review by peers of what we have done in our control room. You know, that's after we incorporate the modifications.

(Slide)

Our in-house task force was chartered with two main areas. First, to perform the control room and shut down panel reviews. Now, these are based on operational reviews of other plants by the BWR owners, the generic program and by the NUREG 0700 guidelines. The second facet of the in-house task force is to provide coordination and change control. In otherwords, they reviewed all our control room design change where human factors are concerned.

Now, there's an interface here with emergency procedures preparation and other Three Mile Island changes that came about as a result of TMI including the emergency response information system and other regulatory documents such as regulatory guide 1.97.

Now, the task force is composed of plant operations personnel, project engineering, the architect engineer and a human factors specialist from general physics.

(Slide)

The major improvements as a result of our in-house review can be categorized in three different areas. The control display review which were aimed at relocation or deletion of controls and indications to improve operational grouping to achieve better operator procedure and panel integration.

The second area of improvement is in the enhancement area. Enhancement reviews are aimed at application of mimicking and demarcation, improved legend plate design, and meter recorder scale adequacy to improve operator recognition and response.

And the third area of improvements deals with an annunciator system. A general annunciator system was redesigned. We grouped related alarms and we upgraded alarm wording so the operator would have better recognition of what the event is.

Now, I'd like to show you a couple of photographs.

(Slide)

The first photograph shows the control room bench board, a portion of the control room bench board prior to any modifications. As you can see, there are no lines of demarcation. The description for the system is very small, hard to read, you can't tell which instrumentation is located with which controls.

Now on the right you will see the same panel after we have mocked up by way of taping and cut outs this part of the dashboard. I'd like to point out, as you can see this area right here which has been outlined, is the same as this area right here, prior to the changes. Notice the lines of demarcation around not only the controls portion of the panel but also the instrumentation. The annunciator is directly above the system and are for that particular system. Another slide will show a close up view of that, reactor water clean up system and some of the usability if you understand what I'm talking about.

The reactor water clean up system legend plate has been increased in size. Notice the mimicking between components, the lines between control switches.

(Slide)

Another view of that panel. This is the reactor recirculation flow control panel. Again, the mimicking between control components. Notice the two recorders that are shared by the reactor recirculation. One for temperature and one for flue closed, and the lines that outline that shared instrumentation system.

(Slide)

In summary, the program began with in-house reviews and will continue through 1982. The BWR owners group independent review has been scheduled for 1983. In 1983 the panel changes as we described it in the previous pictures, started in March of '82 and will be essentially complete by January of next year, when the open items to be completed by fuel load. The NRC report will be issued six months prior to fuel load.

In summary, we are involved with a very aggressive human factors review program composed by an in-house and peer group later on. And we know that this will definitely enhance the operator machine interface and improve the save and reliable operation.

MR. EBERSOLE: I couldn't help but notice, when I looked at your control room, there seemed to be a minimum of flow sheet representation, mimic flow sheets. Did you find that--am I correct in this?

MR. CORCORAN: A minimum of flow sheets?

MR. EBERSOLE: Yes, the diagrammatic aspects of the control system like the RHR system you just showed us there.

MR. CORCORAN: That's true. We tried to mimic the main flow paths from where we could, where we could relocate controls to do this. The benchboard was designed with no mimicking at all.

MR. EBERSOLE: That's what I noticed.

MR. CORCORAN: Correct.

MR. EBERSOLE: Did you simply find that not to be profitable? It's not always that way.

MR. CORCORAN: Like I mentioned, the major flow paths were mimicked. We felt that that was adequate.

MR. EBERSOLE: I see.

MR. CORCORAN: Any further questions on term review.

DR. LIPINSKI: I have a question.

DR. PLESSET: Yes. Dr. Lipinski has a question.

DR. LIPINSKI: Recently I read an article related to the computer industry and the allergic reactions to plastics that are associated with computer products. In closing up your control room and saying you can stay in that condition for 30 days without any refreshing air coming in, have you looked at the plastics that are in that control room and what they contribute to the air supply as to whether there would be allergic reaction with the people who would be in that room under those conditions?

MR. CORCORAN: Are you referring to the plastics that --

DR. LIPINSKI: Your cables are plastic covered. You'll have insulator boards that are in your panels that are plastic.

MR. CORCORAN: I can't directly answer that question. If you're dealing with fire protection --

DR. LIPINSKI: Well, not fire protection, but this indicated that people were having severe reactions and their eyes were burning and these were directly related to vapors given off by plastic material.

MR. RAY: Under normal ventilating conditions?

DR. LIPINSKI: Yes, under normal conditions. Well, they didn't say if you're in a room and the room -- you're at home or something like this and you don't have an air filter unit going, then conceivably you've got static conditions.

MR. RAY: But I mean in the absence of a high temperature source or something of this nature.

DR. LIPINSKI: Yes, this is just ambient conditions, where these vapors come off the plastic materials and people are reacting to them.

MR. CORCORAN: We'll have to get back to you on that one. I do not believe we have looked at that situation.

DR. PLESSET: I was going to suggest, Mr. Corcoran that we take a ten minute break at this time and come back for the rest of your presentation. Let's have a ten minute break.

(Whereupon, a ten minute recess was taken.)

DR. PLESSET: Let's reconvene and continue.

MR. NELSON: Dr. Pleset?

DR. PLESSET: Yes.

MR. NELSON: We -- there was a question that was asked during the last presentation relating to control room habitability. We'd like to at least respond to that question before we go on any further.

DR. PLESSET: Fine.

MR. NELSON: I'd like to ask Frank Owen, our principal engineer in that particular area to address that question. If you would restate it please, I think it will help him a little.

DR. PLESSET: What was the limiting factor that determined how long one could operate with a closed control room.

MR. OWEN: The limiting factor would be the oxygen content in there and there's enough air and oxygen to run for more than three or four days and the condition that causes us to close off the control room will be a chlorine incident which should be over in a few hours and so therefore the other consideration might be temperature but our chillers are qualified and so we'll have normal temperatures in there for the duration.

DR. PLESSET: So it's a matter of a few days rather than more or less indefinitely, right?

MR. OWEN: You mean as far as closing off the control room?

DR. PLESSET: Yes.

MR. NELSON: Does that answer your question.

DR. PLESSET: Yes. I got the impression it could be more or less indefinite from the presentation but it's relatively short, a few days.

MR. OWEN: Well, we're talking probably more in the order of a week.

DR. PLESSET: A week.

MR. OWEN: We can look up the exact numbers and if there isn't, you know, and get that for you if it's necessary.

DR. PLESSET: No, that's all right.

Then Dr. Lipinski had another question about the effect of emission of plastic materials in the control room. Is that taken into account? Is that your question?

DR. LIPINSKI: Yes.

MR. NELSON: Frank?

MR. OWEN: It's all right.

MR. NELSON: Let me take it please.

MR. OWEN: All right.

MR. NELSON: I understand that you, Dr. Lipinski, you have an article that relates to this particular subject matter. We have not seen the article. I think it might be more appropriate if we could see the article before we responded and make sure we respond to the right issues.

DR. PLESSET: That's okay, that's fine.

MR. NELSON: So if you could make that available to us, I think we can try to answer that.

DR. LIPINSKI: It's strictly generic though, because the plastics that are being used today do give off odors. If you saw this business of insulating your house with I think it's styrofoam, now they're recommending against it because the odor from the plastic finds its way into the building and it's toxic. The general issue though, is given the range of plastics that you use and the fact that they do emit odors and if you're circulating, well, when it's being swept out on a continuous basis but if you seal up what plastics do you have and what do they give off and are they serious?

It may be a non-issue but to say that you can --

MR. NELSON: The general feeling we had, we discussed this on a break -- the general feeling we had is we didn't think it would be a particular problem however, we haven't really looked into it in that much detail to really give you the answer you deserve.

MR. OWEN: I think we've got a couple of mitigating things, too, and one of them is that the material that's given off by plastics will be absorbed by activated charcoal and so therefore, even the circulating system will assist in that and the other one is, that we haven't identified any toxic substances here. We don't have any -- nobody has, you know, the REG guides or anybody else has given us anything that these plastics are giving off a toxic subject, maybe allergic, but not toxic.

MR. NELSON: Maybe Frank, maybe we ought to reserve any further response until we've seen the article.

DR. PLESSET: We can leave it at that and thank you. Mr. Corcoran, the floor is yours.

MR. CORCORAN: The next subject is decay heat removal.

(Slide)

Following a reactor shut down, steam generation continues at a reduced rate to the core efficient product decay heat. In the normal sense, the main steam is directed to the main condenser by way of the turbine by-pass valves and the steam is condensed in the condenser and feedwater then is supplied back to the reactor vessel to maintain water level.

Now, heat is rejected to the cooling towers by way of the circulating water system. Now, as soon as the main steam pressure has been reduced to the point where you have insufficient to maintain a steam jet air jet performance, at that point, we want to go into the shut down cooling mode of the RHR system. Now in this mode --

MR. EBERSOLE: Pardon me, may I ask a question? You have a station auxiliary boiler, don't you?

MR. CORCORAN: Yes.

MR. EBERSOLE: Can you use that with the ejectors?

MR. CORCORAN: No.

MR. EBERSOLE: No. You cannot.

MR. CORCORAN: Cannot use it with the ejectors. The pressure of the rejectors is something like 200 pounds. The auxiliary boiler does not provide steam but at a very high pressure.

MR. EBERSOLE: Is this a more or less standard mode of operation? Inability to use the air ejectors all at the station bar?

MR. CORCORAN: Yes, I believe it is.

MR. EBERSOLE: Okay, well, thank you.

MR. CORCORAN: Now we're at approximately 135 pounds in the reactor pressure vessel. We would like to go into the shut down cooling mode of the residual heat removal system, and cool down the cold shut down.

(Slide)

In order to do this, we will take a suction from the A recirculation loop upstream with the recirculation pump past through these isolation valves to either one of the

A or B RHR loops. From the discharge of one of the RHR pumps, we will pass through the RHR heat exchanger and we will go back to the downstream of the main recirculation pump, so the flow path then comes from the inlet right here through the RHR system, back through the recirculation loops, through the jet pumps and through the core and up and down and out again.

Now, the rate at which we cool down is controlled by the position of the heat exchanger by-pass valve, right here. And we used stand-by service water provide a cooling means for the heat exchanger. The heat is rejected then to the cooling towers or to the spray ponds by way of the stand-by service water system.

(Slide)

Now in this case, I'd like to describe the decay heat removal when the reactor pressure valves are isolated from the main condenser.

MR. CATTON: How well are your spray ponds going to work when they have all that volcanic ash all over them?

MR. NELSON: We have our task force as we mentioned earlier that is evaluating the system that is in place, the Trojan. Involved with that task force also, not only the evaluation of the Trojan system but also involved with that is the evaluation of the U.S.G.S. concerns that are placed in the SSER. We're under evaluation right now. We are in fact looking at ash in critical areas like the heat sink. The answer is it would sink. We do have some concerns that we are looking into related to how we would work with that and how much we would have to worry about. So that's kind of under study right now so we really don't have the solid answers for you but the answer is we're not ignoring it, we are in fact looking at it.

MR. CATTON: But it doesn't just float on the top?

MR. NELSON: My indications are that it does not.

MR. CATTON: You're going to test it to find out.

MR. NELSON: We will. We're looking into it, okay, so we're evaluating what U.S.G.S. told us and the SSER and we're certainly looking into that. We owe the staff a response sometime later this year.

MR. CORCORAN: I'd like to recap where I was. We're trying to cool down the pressure vessel. We are isolated from the main condenser by way of the MS, main seal isolation (ph) valves being closed.

The reactor pressure vessel relief valves will pass the team to the suppression pool in this case to maintain pressure and we will make up to the reactor pressure vessel by way of the high pressure porous spray system, from the Class A storage tank, or we can make up to the reactor pressure vessel by way of the reactor core isolation cooling system better known as the RCIC system from either the Class A storage tank or the suppression pool.

(Slides)

Now the RCIC system takes a portion of the decay heat or takes a portion of the steam from the vessel and drives the turbine and the pump, takes a suction on either Class A storage tank or the suppression pool. In this mode, the pressure vessel can be depressurized down to the neighborhood of 100psig at which point we would then like to go into the shut down cooling mode of RHR, just the same as I described a few minutes ago, the normal case.

(Slide)

Now I'd like to describe the case in which the RHR shut down cooling mode is unavailable. Initially, we have got the pressure in the vessel down to the neighborhood of 100 psig. We find that as an example, the suction valves to the RHR loop from the recirculation loops cannot be opened. If this is the case, we will not be able to use the shut down cooling mode of RHR, however, we can continually pressurize the vessel by way of using the relief valves, venting steam to the suppression pool. We can take a suction on the suppression pool by way of one of the three RHR loops going through either A, B or C. In this case, we show going through the B loop and pass it to the heat exchanger and back to the vessel through the injection, in otherwords to the low pressure coolant injection path, or we can take the low pressure core spray pump which takes a suction from the suppression pool which is not shown on the drawing and we can provide water back to the vessel. In this mode, the heat is rejected to the suppression pool and the RHR system will take that water, pass it to the heat exchanger, the stand-by service water will then cool that water and will reject the heat to the stand-by service water spray ponds.

MR. EBERSOLE: Pardon me. What if this problem develops just after you've taken the lid off, so you can't pressurize?

MR. CORCORAN: After you've taken the vessel lid off?

MR. EBERSOLE: Yes.

MR. CORCORAN: You're already down to less than 200°F?

MR. EBERSOLE: Yes, and then you lose the, by malfunction of some sort, you lose the valves off. Can you then handle the cooling problem subsequent to that?

MR. CORCORAN: We will probably not have a cooling problem, because we have other systems at our disposal. We have reactor water clean up system which can be used to maintain cooling shut down condition at this point. We have CRD system which supplies cool water to the vessel.

MR. EBERSOLE: Do they have enough mass flow to keep it below boiling?

MR. CORCORAN: We have the feedwater pumps which can maintain additional cold water to the vessel. The combination of these things will be maintain --

MR. EBERSOLE: It's not an inventory problem, it's a temperature problem. Will you be -- will you have to boil the pool?

MR. CORCORAN: I believe not. We will not have to boil because we can pass the cold water back to the vessel. We can draw off excess water with the reactor water clean up system.

MR. EBERSOLE: Okay, good enough.

MR. CORCORAN: In summary, we have shown that we have several diverse means available to remove decay heat from the core and to bring the reactor to the cold shut down condition.

(Slide)

This includes a degraded or abnormal condition of which we have an unavailability of the shut down cooling mode of the RHR system. That concludes my comments on this topic.

MR. EBERSOLE: In the long run, all of the heat out of the reactor after it's shut down and not connecting to the condenser has to go to the spray pond, doesn't it, eventually?

MR. CORCORAN: The heat can be directed to the cooling towers. The stand-by service water --

MR. EBERSOLE: That's what I meant. That is where it all goes.

MR. CORCORAN: Either the cooling towers or the spray ponds.

MR. EBERSOLE: You can also take it to the cooling towers.

MR. CORCORAN: Yes. It would be the normal course of business, take it to the cooling towers.

MR. EBERSOLE: How do you take the -- okay, that's if -- that's if I have the main steam isolation valves closed, if I've lost the normal heat sink I don't take it to the cooling towers then, do I?

MR. CORCORAN: Yes, we can take it to the cooling towers because the stand-by service pumps will direct water to the cooling tower inlet basin by way of the cooling towers. We'll go to the cooling towers and go back to the basin.

MR. EBERSOLE: I see, so you have a diverse path then?

MR. CORCORAN: Yes, and that basin will provide water to the stand-by service water spray pumps.

MR. EBERSOLE: So you really are not totally dependent on those two spray headers over the two pumps?

MR. CORCORAN: That's correct.

MR. EBERSOLE: And you know, the question was whether tornadic winds would blow them down. You'd have a problem, since they're not qualified.

MR. CORCORAN: Since we are not dependent upon the service water, stand-by service water spray ponds for this evolution, there's not a problem.

MR. EBERSOLE: Thank you.

MR. CORCORAN: The last topic I wish to discuss is the emergency operating procedures.

(Slide)

Emergency Operating Procedures are those plant procedures that direct actions necessary to mitigate the consequences of a transient or an accident that may cause a plant parameter to exceed a reactor protection system set point or an injured safety feature set point.

Prior to Three Mile Island, the plant operators role in the mitigation of an accident, was event specific.

In otherwords, the event orientation required the operator to diagnose and to respond to one of several predetermined accident scenarios. If you all remember, we had procedures which describe small break accidents, large break accidents, stuck open relief valves, loss of feedwater pumps and those kinds of things which the operator tried to respond to.

Now, subsequent to TMI lessons learned, the plant operators' role shifted. During an emergency he would try to maintain vital safety functions such as adequate core cooling, regardless of where the cause of the accident had been diagnosed.

Now, this shift in philosophy was implemented by the BWR owner's group development of generic emergency procedure guidelines. These symptom based guidelines used parameters such as low water levels or high dry wall pressure which are symptomatic of both emergencies and events which may degrade it to emergencies. The objective is to restore this parameter to stabilize the plant and to ultimately bring the reactor pressure vessel into a cold shut down condition if necessary.

Now, these emergency procedure guidelines accomodate multiple failures without requiring the operator to diagnose a specific event or set of events.

(Slide)

The next slide shows the organization of the emergency procedure guidelines. At the present time, the guidelines are under development and what we presently have is we have two, we have two main guidelines, the reactor pressure vessel control guideline and containment control guideline.

Within the pressure vessel control guideline we will enter by way of one of these abnormal parameters and we will then -- assuming we have a low water level, we would then go to a level control guideline which would then try to restore the water level and stabilize the plant and then, we would then go out of the guideline back to a normal situation.

The same holds true for the containment control guideline, based on one of the entry conditions we would then go into -- if we had a high dry wall temperature, for example. We would then go into the guideline for that and we would take care of the problem in that manner and then remove from the guideline and go back to normal conditions.

(Slide)

The supply system has been and continues to be an active participant in the effort of development and refining these emergency procedure guidelines. We are presently using these guidelines as a basis to develop our emergency operating procedures. These emergency operating procedures will be written plant specific. The guidelines are written in the general fashion for all the BWRs. Our implementation plans for the emergency operating procedures will follow the intent of NUREG 0899 which addresses the following areas. We will use a writers guide which will be written by us to confirm that we have -- excuse me, We will be using a writers guide to ensure the consistency in these procedures so they're all written approximately the same, in the same kind of format. We will do a verification review of the procedures to confirm their technical adequacy and the completeness of the procedure. We will do a hands on validation of the procedures by way of a walk-through through our control room and possibly use on a simulator and we will also provide operator training via a classroom lectures and use on our simulator prior to fuel loading.

In conclusion, the supply system has participated in the industry process to develop emergency procedure guidelines which are the new symptom based guidelines and we know that these will improve the operator's response to emergency conditions.

This concludes my remarks on this subject.

DR. PLESSET: Yes, Jesse:

MR. EBERSOLE: Mr. Corcoran, it looks like you're the right man to answer some of these, one of these questions.

I noticed that the ultimate heat sink, the two ponds that I was somewhat astonished to see that you had some low level, low MPSH trips on the pumps for the stand-by cooling system, indicating that you had a low level in those spray ponds.

MR. CORCORAN: Yes, we do have low level trips.

MR. EBERSOLE: My first reaction to that was, if those ponds are low, where do I go from here and what is your emergency procedure when you suddenly find, I presume that you've got low level in these ultimate heat sinks.

MR. CORCORAN: The low level condition and the ultimate heat sink is very low. It's almost -- I believe it's the basis of the lower level of the suction basin. The pond extends above that approximately 25 feet or so.

The river make up system, the tar make up system provides river water to the ponds. Also the circulating water basin by gravity feed, could supply water to the ponds.

MR. EBERSOLE: I guess I was wondering why that thing was ever there in the first place, on the grounds that it should never get that it should never get that low.

MR. CORCORAN: That's true.

MR. EBERSOLE: So what I have done, I've put a protective interlock on the pumps which it'd never function and you know, it's like having a protective interlock on the landing gear motor. It keeps from running the motor out but it ruins the plane. Is there a valid reason for a low trip on those pumps?

MR. CORCORAN: I'll have to get back with you on that answer.

MR. EBERSOLE: One must ask, when it gets that low, what do I do now?

MR. CORCORAN: Well, we've got two ponds.

MR. EBERSOLE: And you're --

MR. CORCORAN: We've got a source of water for both ponds from the river or the cooling tower basin.

MR. EBERSOLE: It leads me to suspect that you have a reason for believing that you're going to lose the water through a leak or something. Is that a supposition?

MR. CORCORAN: There are no lines in the bottom of the ponds during the ponds. (ph)

MR. EBERSOLE: You did have some leakage problems at one time?

MR. CORCORAN: We did have some leakage problems during construction which were fixed.

MR. EBERSOLE: All right, fine.

MR. CORCORAN: We'll get back with you on that answer.

DR. LIPINSKI: On your relief valves on the reactor pressure vessel, if your main steam isolation valves slam shut, what percentage of rate of flow can put into the wetwell, to pressure from the vessel?

MR. CORCORAN: If you're operating at full power then your MSIVs go closed?

DR. LIPINSKI: Right.

MR. CORCORAN: We can provide enough steam flow to the suppression pool by way of the 18 relief valves to maintain the pressure within the set points.

DR. LIPINSKI: But what percentage of 100% flow is that?

MR. CORCORAN: It is full flow.

DR. LIPINSKI: You can take 100% reactor --

MR. CORCORAN: That's correct. Now, at the same time, yes, at the same time we have a scram signal sent.

DR. LIPINSKI: Well, that's what I was getting at because here earlier we had talked about where it goes to after you had reset pump trip (ph) but your relief valve capacity to the pool would take 100% of what would normally go to the turbine?

MR. CORCORAN: It can in this instant. The same time we have a scram signal and so the steam generation rate decreases rapidly.

DR. PLESSET: He's talking about a failure to scram.

DR. LIPINSKI: I'm talking about a failure, that if you're at normal pressure in the vessel and you close your main steam isolation valve, continue 100% power production, that you get 100% steam through those valves, that you're not limited based on the number of valves you have?

MR. CORCORAN: That's correct.

DR. PLESSET: But the temperature of the suppression pool would go up.

MR. CORCORAN: Oh yes, drastically.

DR. PLESSET: How long will you be able to do that? Until the SRVs won't work anymore? How long would it be, before the suppression pool temperature is excessive, how's that?

MR. CORCORAN: I don't understand the question.

MR. NELSON: Are you saying, how long does it take us to get to the full temperature limit under these conditions?

DR. PLESSET: Yes.

MR. NELSON: The basic ATWS scenario.

DR. PLESSET: Right.

DR. LIPINSKI: Yes, but under this condition, they tripped the research pumps and yesterday you quoted what, 43% power limit it goes to?

MR. CORCORAN: Yes, Mr. Powers will present that, approximately 47% power.

MR. NELSON: Maybe we can do first this one again, this gentleman that is prepared to answer the questions --

DR. PLESSET: Now these are not, these are not criticisms of your insulation. These are generic questions.

MR. NELSON: Yes, we recognize that they are generic and we've looked into them.

DR. PLESSET: All right.

MR. EBERSOLE: One new feature that I got out of this was this is a new high power level which suggests what I think used to be about 4 minutes. It's not even four minutes anymore before you're in trouble.

MR. NELSON: Yes.

DR. PLESSET: You mean temperature limits.

MR. EBERSOLE: Yes, and it also suggests another problem. When you're desperately working to get the stand-by liquid control system in, you may be experiencing pressures which will lead to a hydraulic system leak some place and will dump it overboard as fast as you put it in and you're up the creek. So there's quite a bit of implication to this new high power level.

DR. PLESSET: Well, it's not all that different from some of the other Mark IIs. Right, we understand that. Okay. Well, I think that's all, Mr. Corcoran. Can we go on?

MR. NELSON: We hadn't prepared for this meeting to give our ATWS scenario.

DR. PLESSET: No, I know you hadn't so we're not holding that against you.

MR. NELSON: We certainly have looked into all these subjects and we're working very very closely with G.E. and all the other utilities.

DR. PLESSET: We're not holding it against you, be sure of that.

MR. NELSON: We certainly can offer something or send something to you if you wish.

MR. EBERSOLE: Mr. Chairman, may I ask Mr. Corcoran one question?

DR. PLESSET: Okay, sure.

MR. EBERSOLE: Due to the enthusiastic nature of all these pumps that pump water in on this reactor, one then looks at the opposite end of the question and maybe you don't stop when you should and maybe you over fill the boiler, you know it's the other end of the spectrum, and the water goes on up to the top and goes through the dryers and separaters and gets out into the main steam lines. Could you say a few words about what stops that unfortunate process and whether it could ever actually dump water into the main steam lines and if it did, would the main steam isolation valves close against the enormous hydraulic loads that they would suddenly face if that were the case?

MR. CORCORAN: You have to recognize that there are high level trips on high pressure core spray pump --

MR. EBERSOLE: Are these safety grade double tracked?

MR. CORCORAN: Yes, on that system.

MR. EBERSOLE: That's the core spray pump.

MR. CORCORAN: Pipe pressure core spray pump.

MR. EBERSOLE: What about the main feeds?

MR. CORCORAN: The main feedwater system will also trip the high water level in the reactor pressure vessel.

MR. EBERSOLE: Is that double tracked?

MR. CORCORAN: I believe it's redundant also.

MR. EBERSOLE: I think you better look at that.

MR. CORCORAN: The high water level trip is redundant.

MR. EBERSOLE: For the main feeds?

MR. CORCORAN: Main feed system. High pressure core spray system, reactor core isolation cooling system also has this feature.

MR. EBERSOLE: And so what you're saying, you've got double tracked over fill protection. Is that -- I don't want to put words in your mouth --

MR. CORCORAN: Yes. We have protection, automatic protection by way of the high level set points, the reactor pressure at some water level. In addition to that, we have emergency procedures which allow the operator to monitor this water level condition. He knows this is happening by way of instrumentation.

MR. EBERSOLE: So we've got the reasonably high assurance that this will never happen.

MR. CORCORAN: That's correct.

MR. EBERSOLE: I guess the other end of the question, but if it did will the main steam lines carry the water load or will they cave in?

MR. CORCORAN: If it did, the main steam lines will carry the water load. It's similar to a code pressure vessel hydro at a lower pressure --

MR. EBERSOLE: Will they --

MR. CORCORAN: Filled with water.

MR. EBERSOLE: Will they carry the weight without sagging?

MR. CORCORAN: Yes, they will carry the weight.

DR. PLESSET: Any other questions?

MR. CORCORAN: The next speaker is Chris Powers. Chris Powers is the reactor injury supervisor on the number II plant staff.

DR. PLESSET: Thank you.

MR. NELSON: Dr. Plesset, during the courses of meetings that we had yesterday and there were a few questions that came up that we deferred very intelligently to the right person. The right person is now at the podium and he is prepared to answer at least a good portion of the questions at this time so if we missed the point on the question, please don't hesitate to restate it but Chris is prepared to respond to those questions.

DR. PLESSET: All right, fine, thank you, Roger. Go ahead.

MR. POWERS: May I propose that we answer questions in this interim period prior to lunch and then after the lunch break I'll continue on with the presentation on the subject you see there.

DR. PLESSET: Fine, that's very good.

MR. POWERS: There were a number of questions raised. The first one I would like to address is the question from Mr. Lipinski yesterday that dealt with core stability and what the natural circulation power level we would achieve, should we experience a two pump trip.

What I'm putting before you right now is a simplified drawing of our power flow map which indicates the best conditions under which we intend to demonstrate plant performance during our power extension test program.

(Slide)

I'd like to draw your attention to the shaded area Test Condition 4 which is this area right here. You can see that it's bounded. This is our natural circulation line. It is bounded in power level by approximately 42% and 48%. This particular power flow map predicts for us what the power level would be should we trip the recirculation pump from 100% equilibrium conditions. We would basically follow this line down and achieve this particular power level in the natural circulation mode without recirculation pumps and service.

Now, we have submitted to the Staff the results of poor stability analysis or power levels that exceed this particular level and are more up in the order of 55% or so. The results of that analysis indicates that our decay ratios are on the order of 0.6%.

MR. EBERSOLE: A question, please.

MR. POWERS: Yes, sir.

MR. EBERSOLE: That power condition you described. Was that at the relief set point of the safety relief valves or the normal steam pressure? There would be a difference.

MR. POWERS: Excuse me, sir.

MR. EBERSOLE: That terminal power level would be altered by the pressure level of the reactor, wouldn't it?

MR. POWERS: To some extent, yes, that's correct.

MR. EBERSOLE: So was the condition for the normal steaming, normal pressure and normal content?

MR. POWERS: Yes, the test condition that I have shown here is, assuming we're under normal pressure control, by the DH system (ph).

MR. EBERSOLE: How much worse would it be -- I know it would be worse if you were at the relief safety set point? Would it be higher power? Well, it would be higher power, but how much?

MR. POWERS: It would be higher power. I'm not prepared to answer that directly.

MR. EBERSOLE: It might be significant because the void compression problem is present.

MR. POWERS: Yes, I understand the transient and again I'm not prepared to discuss the utmost scenario. I'd like to also clarify for Mr. Lipinski. I believe his question also involved that the power level that we were discussing here was significantly different than what he had understood from previous presentations from the General Electric Company.

I believe that the number Mr. Lipinski was quoting was something on the order of 30% to 35% which comes from a different product line which is a BWR 4. G.E. has submitted the results of their ATWS analysis for that product line. In addition, I believe that number has inherent in it assumptions that for the particular plant analyzed, they implemented an alternate 3 modification for the ATWS concern which .nvolves tripping the feedwater system and allowing water level to decrease to the point where HPCI injected and continued plant operation occurs with the lowered water level and HPCI injection which changes the amount of core flow induced through the core, reduces the amount of moderation within the core, increases the void fraction and reduces the power level into the ranges that he was quoting yesterday.

MR. EBERSOLE: Doesn't all this sum up to the fact that this plant looks a little worse for the ATWS problem than the earlier plants?

MR. POWERS: I am not prepared to draw that conclusion.

DR. PLESSET: How did you get to that, Jesse, so quick?

MR. EBERSOLE: Well, the apparent higher power against an already extremely too short interval for recovery on the older plants, suggest that here there may be only, I don't know, two minutes, one minute.

DR. LIPINSKI: When G.E. first made their presentations, the discussion hinged on the ten minute interval with respect to boric acid and the staff says you know, if it's longer than 10 minutes, manual injection is satisfactory. If it's less than 10, it has to be automatic. When G.E. came back with their second round of analysis they were quoting numbers like 2 to 3 minutes.

MR. EBERSOLE: Well, this is worse.

MR. POWERS: And these were not for plants that were 47% power, because now unless your water inventory is considerably higher, your suppression pool temperatures are going to arise much faster with this type of power production.

MR. EBERSOLE: Chris, what I'm getting around to, the recirc pump trip was a great thing in it's day but maybe it's suddenly lost its's significance unless you've got some time to do something with the suppression of power. You may have just lost your time within which to do do anything. That's all I'm saying. I think you should put an intensive investigation out for that aspect. We are riding on recirc pump trip to give us a not too comfortable interval within which to shut it down. That comfortable interval I think is getting extraordinarily short.

MR. POWERS: Mr. Ebersole, the feature that we have in our plant, that is, recirc pump trip, provides us with some very tangible benefits for other more credible accidents that --

MR. EBERSOLE: I know, I understand. I'm going to the ultimate state.

DR. PLESSET: We've pushed him into ATWS.

MR. EBERSOLE: Oh yes, I guess we have.

DR. PLESSET: That may not be entirely fair. It's not only his problem.

MR. EBERSOLE: His problem is one of the worst of any that I've heard.

DR. PLESSET: I don't think it's really that much different than LaSalle.

MR. EBERSOLE: Well, if LaSalle's core is the same as this one, then --

DR. PLESSET: I think it is. Isn't it the same?

MR. CORCORAN: THat is correct.

MR. EBERSOLE: Okay, then I guess there's no difference. I guess I'm talking to the whole class of these new things.

DR. PLESSET: Right, right.

MR. EBERSOLE: But they're distinctly different than the old ones.

DR. PLESSET: Oh yes, right. And this is something for ATWS consideration all right. That's certainly true.

MR. EBERSOLE: I'd like to have the staff give us the response inthe generic context of what's happening to us here.

DR. PLESSET: Yes, I think it's now something that the staff has to get into and let us know about these things and not only Mr. Ebersole, Mr. Lipinski and I will all be interested in what they come up with.

Now, you say there's a meeting on this?

DR. LIPINSKI: Yes, I just checked my calendar. It's scheduled for October 1 in Washington, on ATWS with the ACRS Subcommittee and I don't know what the total --

DR. PLESSET: Which one is that?

DR. LIPINSKI: ATWS.

DR. PLESSET: Which Subcommittee?

DR. LIPINSKI: The ATWS subcommittee. I think Dr. Kerr is chairman.

DR. PLESSET: That's Dr. Kerr. Do you ever get any data from those? Do you get any feedback from those other subcommittee meetings?

MR. POWERS: Definitely.

MR. NELSON: Are you talking about ACRS Subcommittee meetings?

DR. PLESSET: Yes, this is one that Dr. Lipinski points out is coming up --

DR. LIPINSKI: October 1.

DR. PLESS^^: October 1 on ATWS.

DR. LIPINSKI: I haven't seen the agenda as to whether we'll hear anything from General Electric or the Staff on these new BWRs. It would be very important.

MR. NELSON: Maybe we can answer that more directly as far as our involvement in these kinds of activities. My manager Jerry Sorensen is the chairman of an ATWS group and maybe he can address that more directly as to exactly what our involvement is.

DR. PLESSET: Be patient, Mr. Powers. Don't go away.

MR. SORENSEN: As Roger mentioned, I'm manager, or the chairman of the AIF ATWS group. Jerry Sorensen, manager of licensing for the supply system. We are aware of the upcoming subcommittee meeting with the ATWS subcommittee and it's my understanding that the utility group on ATWS does plan to make a presentation at that meeting and I have seen nothing further as to what the overall agenda will be but I do understand that the utility group has been asked to make a presentation. That has been largely supported by the BWR owner's group and supported by General Electric Company. I'm sure that none of them are aware of the discussions that have taken place here in the last couple of days, so I suspect that they're not prepared right now to discuss that topic but we will make them aware of what has gone on here the last couple of days and see what new things we might be able to come forward with.

DR. PLESSET: You might get some of the Mark III people involved, Jesse. They're not any better off and may be a little worse. Grand Gulf is certainly ahead of this plant in power level, above it.

MR. EBERSOLE: It's interesting how this matter kind of crept along under the rug so long.

DR. PLESSET: Well, I don't think -- we knew it was there.

MR. EBERSOLE: This 47 -- at least I didn't. I was, maybe I should read more but this high power level, I didn't grab that.

DR. PLESSET: It's been there for quite a while. Well, thank you, Mr. Powers. Why don't you go on.

MR. POWERS: The next question that I'd like to address is one that was raised very early in the program and had to do with the differences between the LaSalle and the WNP-2 core design.

DR. PLESSET: Specifically you were a little higher power I think.

MR. POWERS: Yes, our thermal reading was 3323 megawatts thermal as compared to 3293 for the LaSalle unit. The fundamental reason for that difference is that we have increased our core flow capability which results in a somewhat -- about a 2% flattening in our power distribution.

We are limited by peak energy generation rate so that we can increase our core thermal power with a flatter power distribution in order to achieve or reach before we reach the 13.4 kilowatts before the peak limit.

DR. PLESSET: You have a higher peaking factor as I recall, don't you?

MR. POWERS: No, I believe we have a lower peaking factor.

DR. PLESSET: Lower. Then I misread that. That's what bothered me. I'm glad to hear that actually it's lower because that fits.

MR. POWERS: And that lower peaking factor allows us to increase the thermal plant output while still maintaining 13.4 kilowatts per foot. We have a 2% higher core flow capability.

MR. CATTON: There was another part of the question, too. The maximum heat flux that is noted for your reactor is 428,000. For LaSalle, it's 361,000. That's a significant increase in the maxim of heat losses.

MR. POWERS: You said maximum?

MR. CATTON: Maximum. The average that's listed in the table is 163,000. The average for LaSalle is 145,000.

MR. POWERS: Our average will go up if we have a flatter power distribution.

MR. CATTON: Twenty percent? Fifteen percent? And also the maximum fuel temperature is up by 100°.

MR. POWERS: That particular table was not prepared by --

MR. CATTON: It was prepared by the Staff.

MR. POWERS: It was prepared the Regulatory Commission. Our design is well-conceived. We have a 2% higher core flow rating which allows us to flatten our power distribution and increase our thermal output roughly equivalent to 1-½% or 2%, which is -- we experienced a 30 megawatt increase between --

DR_ PLESSET: What bothered me in connection with Dr. Catton's question. On page 1-9 of the SER for your plant, total peaking factor is 2.51 and for LaSalle it's 2.25. And this is what I was struck by when he brought the question up. There may be an error.

MR. CATTON: Something is wrong.

MR. POWERS: There has to be an error in this.

DR. PLESSET: I would like it if you would correct that for us.

MR. POWERS: We did not operate with a 2.51 peaking factor.

DR. PLESSET: I beg your pardon?

MR. POWERS: We do not operate at the 2.51 factor.

DR. PLESSET: That's a pretty high factor anyway and there must be an error.

MR. SCHWENCER: DR. Plesset, Al Schwencer from the Staff. I think we do need to check this table. From what I'm hearing here, the staff's table for WNP-2 is incorrect in a number of columns here.

DR. PLESSET: So you'll correct that for us Al? Okay. Thank you.

MR. AULUCK: We will provide the full committee the correct one.

DR. PLESSET: Yes, that will help people understand this a little better. Okay, thank you.

MR. POWERS: But we do have a different flow control power configuration and we've managed to increase our total core flow by 1-½% which allows us to flatten the power distribution, increase our thermal output for the same peak, kilowatt per foot and our average generation rate goes up accordingly.

DR. PLESSET: You don't have any problems with flexibility of operation with this flatter profile, power profile?

MR. POWERS: No, we do not. We are not limited by our maximum average plant regeneration rate which is typically a problem if you run with flatter power distribution.

DR. PLESSET: Yes, but you're not troubled by that?

MR. POWERS: No, we're not. Our analysis shows we have sufficient margin from the MAPLHGR limits.

DR. PLESSET: Thank you, that helps. I feel a little better now that there may be an error -- well, I'm sure there is an error in that particular number.

MR. CATTON: This might be the fellow to ask. In the SCR there was also some discussion of a stability analysis. Could you maybe explain to me what that's all about?

MR. POWERS: We have a cycle 1 specific core stability analysis that was performed on the G.E. fuel for our initial cycle. During the course of the project, we have elected to go to Exxon reload cores. We have not submitted stability analysis to take into account differences in the fuel types, or subsequent core operation. We have a license condition imposed upon us that we cannot operate beyond cycle 1 without performing additional core stability analyses.

MR. CATTON: Oh, okay. Gee, then there's really not much to it. Thank you.

DR. PLESSET: If you'll let me address you on another question. I'm building up faster than you can answer them, maybe. Had you any plan to develop familiarity with any of the advanced codes NRC has made available, like RELAP-5 or TRAC within your own house?

MR. POWERS: That question would be more appropriately addressed by other individuals.

DR. PLESSET: Just as a matter of information.

MR. POWERS: I can't answer directly to your question.

DR. PLESSET: I beg your pardon?

MR. POWERS: I will attempt to get an answer directed to your question.

DR. PLESSET: Maybe Dr. Shen.

MR. NELSON: Yes, I was just going to say --

DR. PLESSET: May be able to tell us.

MR. NELSON: Is Dave Larkin in the audience? I think he may have answered one of those questions yesterday relating to RELAP.

MR. CATTON: I asked that question a little differently and the answer was no.

DR. PLESSET: On RETRAN. You're not planning to have any in-house capability on any of these codes?

MR. NELSON: Franz, go ahead.

MR. MARKOWSKI: Franz Markowski; I'm the assistant design engineer. I have knowledge of two persons right now who are using the RELAP code and we have used it since at least to my knowledge for the last four years. We have a WNP-2 RELAP Model and we have reproduced some of the General Electric Chapter 15 licensing transients with it.

DR. PLESSET: Well, I'm very glad, pleased to here that. Which RELAP version were you using? Do you recall now?

MR. MARKOWSKI: I believe it's 5 but I cannot be sure. I can go back and find out.

DR. PLESSET: I would like to know, if you can do it without too much difficulty.

MR. MARKOWSKI: All right, I will find out.

DR. PLESSET: I think that the committee will be interested to know about your developing your own independent capabilities so that you don't have to go outside to make an analysis if you need it.

MR. MARKOWSKI: Okay, all right. It's RELAP-5.

DR. PLESSET: Oh, thank you. That's about as good as we have.

MR. NELSON: If I heard your carry-over to that, you want us to get back with you as to what our plans are for in-house analysis capability using these codes?

DR. PLESSET: It seems that you do have it already.

MR. NELSON: We demonstrate that we do, of course, know the codes. We have knowledge of the codes.

DR. PLESSET: And you will exercise this capability?

MR. NELSON: Yes.

DR. PLESSET: Thank you, that's what I was glad to here.

MR. EBERSOLE: May I? Chris, something funny about this. It seems to me the trend as you have done here toward higher and higher flows would make the ATWS performance improved due to the lowering of the board content, before we give them power level. I guess the answer to that is you've raised the power output a little bit, is that right?

MR. POWERS: That's correct.

MR. EBERSOLE: So you're back at the old void fraction that you originally had. You're just moving the water faster.

MR. POWERS: That's also correct. We also get about 10 megawatts of electric for that.

MR. EBERSOLE: Thank you.

MR. POWERS: I can continue answering several other questions that were raised if --

MR. NELSON: Ye. , go ahead.

DR. PLESSET: You've got the floor. You'd better keep it.

MR. POWERS: There was also a question asked earlier I believe from Mr. Catton that had to do with bundle lift and LOCA seismic concerns with -- and it's interaction with channel bowing. I understand that from discussions with General Electric that they have recently submitted within the last month, new methodology and new analysis that does in fact account for the amount of bundle bolts that would be experienced due to a differential depressurization rate between the core flow by-pass region and the bundle channel region, such that they do account for this bulging of the bundle in the LOCA and seismic bundle whip interaction.

MR. CATTON: The question had to do with the accounting of the deflection when they already had some deformation at the box.

MR. POWERS: In addition, well, as I understand the analysis, the analysis assumes a certain degree of bulging to start with in the bundle. We have a -- we have committed to the Staff through the licensing process to implement a channel management program in which we will control the amount of bulge that we experience on the channels, resident in the core and discharge those bundles when they appear to reach a significant bowing level such that we're within the, within the bounds of the analysis on the seismic LOCA lift.

MR. CATTON: As I understand it, the way you dc that is you measure the rate at which the rod will drop and basically you measure the friction between the rod and the box, is that correct?

MR. POWERS: That is one approach to the solution, that's correct.

MR. CATTON: That means that you, you're going to do something when the deflection is already enough to rub on the control rod.

MR. POWERS: As I said that is one approach. Our approach has offered an alternative direction. We will aggressively measure the channel bow and we have developed, based on statistics we have acquired from operating plants to date, we have the ability to predict the amount of bow given the resonant time of the reactor, locations within the reactor, some specific material properties of the channel. We can predict when a bundle will reach an unacceptable amount of bows. Our program is primarily based in a measurement program that confirms those correllations and we intend to discharge bundles prior to their reaching an unacceptable level of bow. We're not going to rely solely on this friction measurement as you alluded to.

MR. CATTON: Now, the unacceptable bulge is the point at which you would get into difficulties if there were the LOCA that would cause further deformation?

MR. POWERS: No, our criteria will be based on degradation of scram speeds, of the rods which is a bow level that is less than the bow level that would create a problem for the seismic, the bundle uplift problem.

MR. CATTON: I'll look forward to reading your report.

DR. PLESSET: May I ask you another question in connection with your flatter power distribution. It occurred to me, I wonder what this does to your fuel utilizability? Does this affect the efficiency with which you use the fuel? Do you have to discharge the fuel earlier? Do you get more energy out of the fuel? People don't worry so much about fuel economy anymore but maybe we should.

MR. POWERS: Our analysis shows that towards the end of cycle, we have significant margins to our thermal limits of 13.4 kilowatts per foot. During that period of time, we are examining operating strategies that will extend the bundle useful lifetime or our ability to extract energy from them. Things on the, that have to do with changing the void fraction within the core which would produce a more fissile material with which we could extract an energy from later on in life, that bundle in subsequent cycles, so we are constantly looking at fuel cycle economics and adjusting our operating strategies to account for any fluctuations that would impact on bundle energy extraction.

DR. PLESSET: Do you think he may get a gain out of this flatter profile?

MR. POWERS: I'm not really sure. I'm not completely --

DR. PLESSET: You're giving us what your experience will be after you've run through a couple of cycles, but you don't expect much difference either way?

MR. POWERS: No, I do not. Not for the 1% difference in distribution.

MR. EBERSOLE: Chris, what would you expect to be a reasonable margin of safety about this box uplift problem for a LOCA in view of the end effects, if you do get an uplift? What will happen if you have an uplift is you'll raise the cans and they'll go up and hit the steam separaters? I don't know to what extent this will affect the actual scram. It certainly would do damage to the fuel, but what is a practical safety margin to be sure these cruciform rods go in and do not drag the fuel up? Do you have any feel for how much confidence you need about this? By the way, that channel box deflection probably is not axially uniformed. It's probably worse at the bottom.

MR. POWERS: I would expect that to be the case, yes.

MR. EBERSOLE: Whereas, the blow down load is worse at the top.

MR. POWERS: I guess intuitively I would guess that the bundle uplift problem would not be a severe problem.

MR. EBERSOLE: How high can it lift? Two feet, three feet?

MR. POWERS: Physically how high could the bundle lift?

MR. EBERSOLE: Yes.

MR. POWERS: I believe the separation between the top guide and the upper head, upper shroud head is on the order of, depending on where you are radially within the core, is probably onthe order of 3-½ feet.

MR. EBERSOLE: Three and a half feet.

MR. POWERS: Something like that.

MR. EBERSOLE: Something like a third of the core length.

MR. NELSON: Jess? There's a report that has just been issued by General Electric on this subject and I've just been informed that this subject matter is discussed in the report. In all due fairness to Chris, he hasn't had an opportunity to review this report. We do have some fuel individuals in our plant that have reviewed it and we're evaluating that right now, so I think Chris is maybe, doesn't have the right ammunition at this point.

MR. EBERSOLE: Well, let's defer this.

MR. MARK: I would like to raise a question which I don't believe needs to be commented on immediately but there is this business of the pressurized thermal shock which comes in some forms down to a radiation history of the pressure vessel. I don't think it's a problem for you, but it is a problem that you must obviously have in site and give thought to, and could you tell us just a word on the extent to which you are aware of that and giving any heed to it?

MR. POWERS: We have a specimen measurement program where we have core samples of the base metal of the reactor vessel located at appropriate locations above, around the core that we monitor the fluents and it's effect on the base metal of the reactor pressure vessel. I believe the question that you're referring to is most severe on a pressurized water reactor because they have a much smaller --

MR. MARK: That is certainly true.

MR. POWERS: Much smaller annulus region if you will. We have a very large, relatively large area filled with water that acts as a shield and so our fluences are smaller on a reactor vessel.

MR. MARK: I agree with you entirely, of course, but it is much more a problem for other people than for you. On the other hand, at some time you are almost certain to address questions on that subject and my query, I guess, are you going to be prepared to do so and what you're telling me is, you think you are.

MR. NELSON: Dr. Mark, we have members on our engineering staff that are part of Westinghouse owner's group and of course, Westinghouse is looking into this very deeply with various subcommittees within AIF where we're informed on this issue. We have a safety engineering group that reviews LERS on a continual basis so this kind of information is being fed back to our engineering and plant operations system so we are aware of the concern that is coming forth in this issue and we're abreast with it. Again, Chris has mentioned that the concern now appears to be narrowing in on PWRs. However, we do have two PWR plants as well, we we are involved with that kind of work that's going on in that area in PWR specifically to see it's application to our plant as well.

DR. MARK: What you say is just fine.

MR. EBERSOLE: Let me ask a question. This new high pressure electric driven core spray pump -- it's pretty close to the main feedwater pressure it can deliver. Is there an inhibit on that when it fills the boiler to keep it from going water solid?

MR. POWERS: Yes, there is. Mr. Ebersole, Mr. Corcoran referenced that high level trip on the high pressure core spray system.

MR. NELSON: Yes, we're talking high pressure core spray.

MR. EBERSOLE: High pressure, okay, thank you.

DR. PLESSET: Do you have any more questions that you want to answer? Did you have one?

MR. NELSON: Not after this.

(Pause)

DR. MARK: Would he like to introduce some questions none of us have thought of?

(Pause)

MR. POWERS: There were a number of questions raised by Mr. Ebersole and Mr. Lipinski during our tour yesterday morning.

MR. NELSON: Dr. Catton as well.

MR. POWERS: That I could answer. I believe I've got our responses to them. There was another question however that was raised in this form yesterday that I'd like to address. It has to do with providing jet impingement force protection or shield between the recirculation lines and the CRD insert withdraw lines modules as they penetrate the sacrificial shield and go underneath the vessel.

What I would like to do is simply summarize our response to exactly that question that was raised on our docket and I would like to basically summarize the response that we submitted to the commission at that time.

Fundamentally, we have had an analysis performed that studies the impact of jet impingement forces on CRD withdraw lines and how much force or how much deformation of the line is required in order to begin to effect our ability to scram the rods.

That study indicated that we could take up to an 87% reduction in the flow area of the withdraw line before we begin to affect the scram times at all. In addition to that, we can experience a reduction of the flow area to the point where there's only 1-½% of the original flow area available and studies have indicated that we would still be able to scram the rods. It would be at a reduced scram speed on the order of about 3 times the normal scram speed. That gives you the spectrum of amount of damage that we can tolerate on the withdrawal lines and still maintain the ability to scram the rods. Now, I might point out that with -- completely taking a CRD withdraw line and holding it completely in half so it has 180° bend in it, the studies have also shown that because of the material properties in the small diameter piping, there is still a 10% flow area remaining which would still allow us to scram the CRD so we don't feel the jet impingement force on the CRD withdraw lines could preclude us from scramming, driving the rods in.

MR. CATTON: I wouldn't have expected that kind of damage. I would have thought that jet impingement would just shake it until one of the ends broke. Those lines are preety long.

MR. POWERS: If we completely sever a line and break the line, that even --

MR. CATTON: Flow vibration is what I'm referring to, not just a steady push by the jet. Do you know why they are putting shields at some other plants?

MR. POWERS: No, I do not.

MR. CATTON: I really think you ought to take a look into that. I don't believe that they would do it without reasons.

MR. EBERSOLE: If I suddenly severed a supply line during a LOCA, does the rod go in?

MR. POWERS: The rod scrams?

MR. EBERSOLE: You see, it has available pressure from the check valve from boiler pressure. The boiler pressure is going away from you awful fast and the time scale, there's a very neat calculation you have to do to see whether you made it before you lost the pressure.

MR. POWERS: I believe the vessel pressurization rate is relatively slow enough to allow full stroke of the scram.

MR. EBERSOLE: What's the depressurization rate on the large LOCA compared to the rod insertion time?

MR. POWERS: I guess I do not know what the actual depressurization --

MR. EBERSOLE: Do you follow my course of thought is here?

MR. POWERS: Yes, I understand exactly what your concern is.

DR. PLESSET: What's the rod insertion time?

MR. POWERS: The concern is the reactor pressure would depressurize more rapidly than the scram stroke.

DR. PLESSET: What's the scram stroke time?

MR. POWERS: Our measured scram speeds are on the order of 2-½, 2.2 to 2.5 seconds.

MR. EBERSOLE: But this is a different cap here, this is a much lower pressure, going in on the boiler pressure itself. The boiler pressure is going away and boiler pressure is also driving the rod, because the supply line from the accumulator is gone.

MR. CATTON: Still, 2.5 seconds is pretty short.

DR. PLESSET: That's pretty short for reactor depressurization. Also, it might still be all right.

MR. POWERS: I might add, Mr. Ebersole, that during our test program, we brought out the scram accumulators and monitored, measured what the actual CRD scram time is without accumulative pressure, relying solely on reactor pressure and we do not see a significant degradation of our scram speeds.

MR. EBERSOLE: But this dry pressure would be going down exponentially.

MR.POWERS: Yes, I understand that.

MR. EBERSOLE: So you wouldn't be getting a representative picture. But mainly --

DR. PLESSET: Two seconds is a fairly short time for the depressurization rate.

MR. POWERS: The depressurization rate --

MR. EBERSOLE: Even on a large LOCA.

DR. PLESSET: Right, even on a large LOCA.

MR. EBERSOLE: Is the degree of damage that you postulate to the rods obtained by how you quantify in sort of break mode rather than the usual simple one where you take a sequential or a split of cross-section of pipe. In short, have you honed the thesis of level of damage to these rods on a complicated and quite involved and therefore suspicious number of conditional requirements that limit the break violence?

MR. POWERS: As I recall, the test program on the withdraw lines that tested under -- tried to simulate two types of damage. One, where you took a long section of piping and held it at either end and crimped it in the middle and just bent it.

MR. EBERSOLE: I'm talking about the damage or the impact or the forces that you're going to apply to it. I'm not talking about the performance of the tubes, I'm talking about the forces.

MR. POWERS: What I was trying to indicate were the two methods in which we applied forces to the point where we got deformation or damage to the withdraw line.

MR. EBERSOLE: Let me tell you my basic problem. I'm finding it a little difficult to believe that in the presence of a large split or circumferential break, you know, the simple minded mode of failure, that I'll have anything left but rags in the vicinity of the break. I simply won't have any tubes at all because of the violence of this hydraulic explosion.

Now, what you have done, I think is said oh, I'm not going to get a break that big, I'm going to get a crack because it has -- it's in a certain region where I can claim a modulated form of break using the NRC methods to reduce the size of the break. Is that right?

MR. POWERS: Are you questionning -- let me make sure I understand.

MR. EBERSOLE: It's the size and degree of the break in the vicinity of the rods. Have you taken a full scale split or a circumferential rupture?

MR. POWERS: Well, let's hypothesize that we have a full size break that completely wipes out all of the CRD withdraw lines.

MR. EBERSOLE: Yes.

MR. POWERS: Under that case, we still have the maximum flow area available to relieve the over piston area and the reactor pressure would drive the control rod drives in under that condition.

MR. EBERSOLE: The last statement you made is the one in question, because that pressure is rapidly decreasing.

DR. PLESSET: That's rapidly in quotation marks.

MR. EBERSOLE: But the question is whether the time is appropriate.

DR. PLESSET: I think you can easily get someone to look up for you what the depressurization is for 2 to 3 seconds and I suspect that it's slow enough so that you're all right. Do you have that or can you get it?

MR. POWERS: I can get that number for you. I believe that that number is greater than 2 seconds.

DR. PLESSET: I would agree with that too.

MR. EBERSOLE: I think it is, too.

DR. PLESSET: It's quite a bit greater than 2.5 seconds.

MR. POWERS: That forms the fundamental basis of our resolving this particular issue, Mr. Ebersole.

MR. EBERSOLE: Mr. Chairman, of course that only accounts for the supply line. If you fold the discharge flat, you go no place. The thesis here is that you won't ever quite fold them flat. You'll have a leak path and therefore obtain a discharge and I don't know how valid that is.

MR. POWERS: The information that was just brought to me indicates that reactor pressure is above

800 pounds, out into 16 seconds following a large break LOCA and it remains above 500 pounds.

DR. PLESSET: That sounds reasonable.

MR. EBERSOLE: Plenty of time.

MR. POWERS: Into 30 seconds.

MR. EBERSOLE: I think, the supply line failure, there's no problem.

MR. POWERS: And again, I might add that during the test program, we test selected drives with the scram discharge volume or excuse me, the scram accumulator valve at reduced reactor pressures as well as full reactor pressures so we have complete confidence that the rod will scram, should we damage the insert withdraw lines.

MR. EBERSOLE: Did you deliberately disperse the tubes so that you didn't have contiguous rods?

MR. POWERS: Yes, sir.

MR. EBERSOLE: And you had this in mind when you did this, I guess.

MR. POWERS: Had the --

MR. EBERSOLE: The damage concept of a local --

MR. POWERS: It has to do with separation, yes it does.

MR. EBERSOLE: Thank you.

DR. PLESSET: Very good. Well, we're happy, relatively speaking.

MR. NELSON: Are you still concerned about the variance (ph), Dr. Catton?

DR. CATTON: I'm just curious as to why they're doing it at other plants. Your arguments sound very convincing.

MR. NELSON: I think the answer is that these arguments are, post-date the insertion of the shields. I think the shields were added, it's my understanding that the shields were added by the architect engineers as an added conservatism prior to being aware of any expense (ph) it had in mind.

DR. PLESSET: Mr. Powers, do you have more?

MR. POWERS: There were four or five questions I believe Mr. Ebersole raised during the tour and I believe he would like to have a response to those?

DR. PLESSET: Sure, why don't we do that.

MR. NELSON: We know the answer to that, Chris.

MR. POWERS: I believe one of the first questions you asked me, Mr. Ebersole was up on the refueling floor when we were looking at the reactor building crane and you had asked whether or not we had dual cable cranes. We do in fact have dual cable, single drum, dual hook, main crane.

MR. EBERSOLE: I believe I asked you the question, did you go via the logic of I will never drop the load, like 125 ton cask or I will drop it but it won't hurt anything? I believe you told me you went both ways? That you can say you'll never drop it with high assurance; second, if you do, you're all right. Am I correct?

MR. POWERS: That is correct.

MR. EBERSOLE: I guess I don't need to pursue that any further. You can drop it.

MR. POWERS: When we were in the diesel generator room, you asked the question whether or not the -- each individual diesel had it's own independent DC system to supply it's control logic and so forth. On our HPCS system which is our division 3, it has a completely independent, separate DC power system that is powered off of it's own SM4 bus. The other two divisions of the diesel have a, come off of the 125 volt division 1, division 2 battery -- 125 volt battery system that I'll be showing you a slide on later in my presentation.

You raised another question --

DR. LIPINSKI: Before you go on, I have one question on those diesels. The motor driven compressors, are those motors on the 125 volt DC?

MR. NELSON: This is air compressors?

DR. LIPINSKI: Air compressors for the diesel start.

MR. POWERS: I believe I have one AC powered and one DC powered.

MR. NELSON: That is correct.

MR. POWERS: One DC is off the 120 -- I believe it's 125 volt DC power for that division and then we have our other AC motor that's powered from the emergency or critical bus for it's respective division.

I believe Mr. Lipinski you asked the question when we were on the 522 elevation and I pointed out to you the pipe chase areas that were closed in a concrete that as they came up the biological shield and turned it and went into the primary containment, you had asked what the design basis for that concrete shield was, and I was uncertain as to whether or not they were actually for radiation shielding of plant personnel protection and in fact they are for normal plant operation when we're in the shut down cooling mode -- those pipe chases are enclosed in the structures for radiation protection and plant shielding.

I think the last question that I have a response to is Mr. Ebersole's question that had to do with a cooling of the generator, on the diesel generators, whether or not there it was room or was taken from outside air. The answer to that question is, it is room air, that is circulated through the generator to cool it.

MR. EBERSOLE: If it's room air, then that leads to the next question. Are there any modes of operation such as fire protection wherein you closed the room by systems which are not seismic class 1 or otherwise, class 1E safety grade competence? Are there any devices which in essence can close the room air up so you have no generator cooling? If you follow me --

MR. POWERS: I understand your question. I do not have a direct answer for that question. I will try --

MR. EBERSOLE: For that room -- it turns out that the generator is cooled by room air and the next question is --

MR. POWERS: The generator --

MR. EBERSOLE: The room air.

MR. POWERS: The generator is rated for 155° or 315°, 311°F are the environmental conditions in which that particular generator was designed for. It has a very high ambient temperature that it can run at.

MR. EBERSOLE: Do you mean it can run via a room ambient of 350°?

MR. POWERS: 311°.

MR. EBERSOLE: 311°.

MR. POWERS: Yes, sir.

MR. EBERSOLE: That's astounding. Nobody can go in there to service it, of course.

MR. POWERS: I believe the scenario we were talking about is say we had a fire in another section of the room or something like that that would require us to --

MR. EBERSOLE: Let me just ask you to look at the potential for blockage of the room, open cycle ventilation system. I assume you don't have a closed cooling system in there?

MR. MARKOWSKI: May I interject? Franz Markowski, System Design Engineer. There are cooling coils, a smaller one and a heavy one which come on automatically when the diesel starts. Or more correctly, the smaller one is normally on and the heavier one comes on as soon as the diesel generator starts and cooling is not achieved by circulating the air out of the room but cooling is achieved by circulating the air through these cooling coils internally.

MR. EBERSOLE: You just answered the question.

MR. MARKOWSKI: Yes, you do not need outside air.

MR. EBERSOLE: Thank you.

MR. POWERS: Those were all the questions.

DR. MARK: I have a question I'd like to ask.

DR. PLESSET: Well, it's up to you. You can't silence a member. Dr. Mark has a very general kind of question.

DR. MARK: Very general indeed. There are many people present here as there were yesterday and this is of course, quite agreeable to the subcommittee and we'd like to think that there are people interested in what it was doing. Many of those will be here because of their connection with General Electric or connection with Washington Public Power and there will be some I suppose who are here because of interest. I'm wondering if those who are here, not connected with one of the organizations who are trying to present their case would be willing to let us know by showing their hands, just roughly, how many of any such there are? Members of the public, that is.

DR. PLESSET: Just one. Well, that shows you that you have a limited attraction because you're not known.

Let's recess for lunch and we'll reconvene at 1 o'clock.

(Whereupon, at 12:02 p.m., the hearing in the above-entitled matter was recessed, to reconvene at 1:00 p.m. this same day, Friday, September 3, 1982, in the same place.)

A F T E R N O O N   S E S S I O N

1:07 p.m.

DR. PLESSET: Let's get back to the meeting and continue with our agenda.

We'll go back to Mr. Powers. Is he here? Oh, yes. Mr. Powers. Will you begin?

MR. POWERS: I'd like to begin my formal presentation in which I'll be covering three topics.

(Slide)

They are AC/DC system reliability.

MR. BIBB: Can we take a minute before we get started and answer a queston that Mr. Ebersole had on a service board pumps (ph).

MR. NELSON: Yes, I think Mr. Rifaye can answer that question.

MR. RIFAYE: This switch is --

DR. PLESSET: Who are you?

MR. RIFAYE: Shafike Rifaye. That switch is merely for maintenance and during outage you can have the pumps maintained or something like that, you don't want an operator to start the pump and just all completely drawing. Because you float the weir and you maintain the area, during, only during outage.

MR. EBERSOLE: Was this because of the level interlock?

MR. RIFAYE: The low level trip.

MR. EBERSOLE: Why don't you just open the breaker and tie it off?

MR. RIFAYE: Because I have it there -- it's just for me to -- it's just for maintenance purpose. I don't have it for operation. For operation when it works, that means the whole spray pond is completely empty so I have no water anyhow.

MR. EBERSOLE: Do you mean that that, now this is the level lock out, right?

MR. RIFAYE: The level lock out, yes.

MR. EBERSOLE: You mean a normal operation, it short-circuited?

MR. RIFAYE: A normal operation once it reach to that level that means the spray pond is completely empty.

MR. EBERSOLE: I know that, but if I also have a malfunction of the switch, the pump stops.

MR. RIFAYE: You can switch to the other three and you have completely two independent drains of --

MR. EBERSOLE: I understand. What's the relative probability that I will go to low level versus the probability that the switch will go bad.

MR. RIFAYE: I can't answer that.

MR. EBERSOLE: I think the odds are fantastically higher that it's going to be about switch malfunctions.

MR. RIFAYE: That's true, but in that case I can switch to the other spray pump and go and bridge it and take it off the circuit.

MR. EBERSOLE: I guess, I don't understand, I mean, do you mean to clean out the pool you're going to --

MR. RIFAYE: To clean the pool and that nobody can start the pump during that time.

MR. EBERSOLE: And you don't depend on opening circuit breakers and locking out the pump for that purpose?

MR. RIFAYE: No, I don't think.

MR. EBERSOLE: This is sort of an indirect --

MR. RIFAYE: It's indirect permissive --

MR. EBERSOLE: You've got a local interlock that's virtually manual.

MR. RIFAYE: That's right.

MR. EBERSOLE: I don't know what to say about it except that I'm suspicious that it's got problems.

MR. RIFAYE: Normally, normally you're going to lose water in the ponds to address the operation and we have 30 days reservoir in both ponds.

MR. EBERSOLE: How frequently do you anticipate that you're going to empty the things to clean them out?

MR. RIFAYE: I don't expect, in perhaps in 20 years or so I might have to.

MR. EBERSOLE: And once every 20 years I'm going to have this switch have to work?

MR. RIFAYE: It's true, I mean, I can, I see your point, you know. Okay.

DR. PLESSET: Let's go on, Mr. Powers.

MR. POWERS: I'll be covering three subjects today as I said. The description of the AC/DC distribution systems and it's associated reliability. I'd like to spend a few minutes and discuss total loss of AC incident and how we would anticipate to responding to such an incident and finally, I'd like to present to you some design modifications that we're making on the remote shut down systems to make it a more reliable system. Before I go into the formal presentation, I'd like to clarify two items from my earlier period of time up here prior to lunch.

I would like to clarify a statement that I made that may have left the wrong impression to the members of the ACRS committee in regards to the air compressors that provide air starting power for the diesel generators.

We have one AC motor that's powered from the emergency bus. We have a second diesel driven air compressor that has it's own DC supply for the starting logic and the starting motive force to start the diesel driven air compressor. This diesel driven air compressor takes a suction from and discharges it's exhaust to the respective inlet and outlet of the associated diesel generator that is providing a start capability for so I think there may be a misconception on what I said earlier on that subject. I'd like to clarify that.

DR. LIPINSKI: Where was that other compressor located because we looked into the one room and I only saw the motor compressors with the receiver tanks?

MR. POWERS: They are located in the same room, completely set behind, back behind the AC motor that we pointed out to you on the tour.

DR. LIPINSKI: Okay, we missed that.

MR. POWERS: Yesterday. The other point I would like to clarify is a statement that I confirmed from Mr. Ebersole in that we felt that we could withstand a cask drop incident. We have a situation analyzed from a radiological protection standpoint and we feel comfortable with our ability to control the radiological consequences of such an incident. We have not analyzed a situation from a potential damage to the fuel pool and what a drop in the cask would do to the fuel pool. Our fundamental line of defense is that we won't drop the cask. So I would like to clarify that.

MR. EBERSOLE: Well, then that gets into an intensive study of this matter of the crane being able to override itself, the duality of the limits which is on travel and torque and so when you -- have you opened the crane designs and it's controls and upgraded to safety grade functions. Those drum drive systems and breaking systems so that you really have a valid basis for safety grade lifting?

MR. POWERS: We have submitted a report in response to a NUREG on control of heavy loads and it's --

MR. EBERSOLE: I'm unfortunately not familiar enough with that to really say that, whether it covers the problem fully or not.

MR. POWERS: What I was about to say, Mr. Ebersole, was that our submittal to that NUREG ona control of heavy loads, addresses the interlocks that we have on the crane, our measures to keep them in service, the surveillance on those, that sort of thing that I believe would address your concern.

MR. EBERSOLE: Suppose I, the over travel interlock fails on the crane and keeps running. What's the ultimate consequence on the drum and the cable? Do I have excessive torque capability?

MR. POWERS: I cannot directly answer that question.

MR. EBERSOLE: You follow my line of questionning?

MR. POWERS: Yes, I do.

MR. EBERSOLE: I'm getting into the box that we call the crane and addressing it as being necessarily having to be designed to reactor grade, class 1E type rationale. Does the Staff not require this? If you invoke infallibility of dropping? And, you have in this case maybe the potential for puncturing a hole in the fuel pump?

MR. SCHWENCER: I think with respect to this plant, Mr. Ebersole, we have not completed the review. We're still -- need to look at this report that they've submitted.

MR. NELSON: I can clarify that a little bit. Chris made a statement that we have responded to NUREG 0612, the heavy loads issue. We have had verbal discussions with the staff and the staff's consultant on this issue. We know what our response is. It has been drafted. The Staff knows what it's going to be, but we have not actually submitted it yet.

MR. EBERSOLE: Mr. Nelson, what I'm really getting at, do you consider the Staff's requirements an adequate baseline for the safety of this crane operation?

MR. NELSON: Yes, we have evaluated the NUREG 0612 requirements and we believe that they're adequate.

MR. EBERSOLE: It's comprehensive, you think.

MR. NELSON: Yes, it is comprehensive and we feel it's adequate.

MR. EBERSOLE: Okay, thank you.

DR. PLESSET: Go ahead, Mr. Powers.

MR. POWERS: I'd like to get into now a presentation that I had prepared that describes the AC power distribution. What I have in front of you now is a -- is the Washington portion of the Pacific Northwest grid, which is commonly referred to within the Benton power administration as the federal Columbia River power system.

(Slide)

It is a little bit difficult to see, but I'll try to point this out with the pointer here. WNP-2 is physically located in this area right here. What I want to point out to you is the major 500 KV transmission lines that criss-cross the State of Washington into which the output of WNP-2 is tied. Here is a major 500 KV line that goes over to the major load center on the West to a portion of the State of Washington in the Seattle-Tacoma area. In addition, we have a major 500 KV inter-tie coming down to the Bonneville Region in this area and continuing on down to another major load center that the BPA grid here in the Northwest services and that is the State of California. I would like to also point out that we import and export a significant degree of power from BC hydro, that passes through the BPA grid. The impression I'd like to leave you here is that the BPA grid has an installed capacity of something on the order of 12 million kilowatts. We are interconnected with grids in the rest of the United States at 100 locations, approximately and there are inter-tied with 17 other transmission systems that tie into the Northwest power grid.

MR. RAY: Mr. Powers, do I read this diagram to indicate that you also have 500 KV ties into Canada?

MR. POWERS: Yes, as I was indicating, we transmit import and export power from BC hydro through the BPA grid to the load center in California.

(Slide)

It's not particularly graphic in this slide however, I would like to point out that there are 27 hydro projects on the Columbia, federal Columbia River power project.

(Slide)

This particular slide is showing you a little bit more detail of the area immediately surrounding the WNP-2 location. We are physically located right there. This symbol represents WNP-2. Here is WNPs 1 and 4 projects located here.

The output of our generator is transmitted to the

Howard Ashe substation where it is connected with the 500 KV system by this line, goes up into the major 500 KV transmission point. In addition, we also have a 500 KV coming into Ashe, going into the lower Monumental Dam complex. I would like to point out while I'm on this slide, one of the major 115 KV transmission system points, the Benton substation -- what I'm trying to point out here is, that we have at least four sources of supply into the Benton substation of 115 KV. We have two lines coming in from the lower Snake Dam complex where Ice Harbor, the lower Monumental, the Little Goose dam are located. In addition to that, it's just off the left edge of this map, I would like to point out that the number of sources of supply of 230 KV power coming into the midway substation which supplies us the major power exitation for our start up transformer which we showed you on the tour yesterday, coming from Midway down through the 230 KV lines into Ashe and then onto our unit.

MR. RAY: You mentioned two 500 KV lines at Ashe and I see one connected to Pebble Springs. Is that isolated from the WNP input?

MR. POWERS: No, it is not. I simply did not choose to --

MR. RAY: So you have three lines there.

MR. POWERS: That's correct.

I want to emphasize that coming into the midway substation, we have as a minimum, four separate sources of supply coming into Midway that come from the various dams on the upper Columbia and the middle Columbia and even to tie into the lower Columbia hydro projects at the La Dalle's and Bonneville Dam complexes.

Also over in the Benton substation as I pointed out, we have at least four sources of supply coming from the hydro project.

MR. SCHWENSEN: The clarification is -- the one to Pebbles Springs, is that an existing line or is that a future planned one to the Pebble Springs Nuclear area?

MR. POWERS: I believe that this -- I believe that this particular line is a future planned area and the major inter-tie with the coal fire units down there is through the 115, 230 KV line that you see coming down towards the area dam project.

MR. RAY: I fail to follow that. Are you saying that the third 500 KV line is a future line?

MR. POWERS: There is an intention to fill, there is on the drawing boards I should say, an intention to build a Pebble Springs nuclear plant by Portland General Electric. That is sometime off in the future.

MR. RAY: I see. Will that be in conjunction with the additional nuclear power units at WNP?

MR. POWERS: I'm sorry?

MR. RAY: Will that be in conjunction with the next units? The rest of your nuclear program?

MR. POWERS: No.

MR. RAY: It's beyond that.

MR. POWERS: It's independent of our activities.

(Slide)

What I was attempting to indicate on this particular slide, this shows you a little bit more detail of the Midway Substation and shows you the ring bus configuration which is connected into the 230 KV supply line that comes into the HOward Ashe substation that's immediately to the North of our facility.

MR. RAY: Do you have a detail of the 500 KV switching at Ashe?

MR. POWERS: I'm sorry, I do not have a slide on that. It is a similar configuration. The ring-bus concept is applied to the 500 KV that you see on the 230.

MR. RAY: So the 500 KV going over to Midway and the one going to Lower Monumental are separately switched?

MR. POWERS: That is correct.

MR. RAY: How about -- is there a transformation tie between this 230 KV bus and that 500 KV ring bus that you mentioned?

MR. POWERS: In the Ashe?

MR. RAY: Yes.

MR. POWERS: No, there's not.

MR. RAY: No transformation.

MR. POWERS: No.

(Slide)

While I'm on this particular slide, I would also like to point out that there is a connection between the Ashe substation and the 230 KV supply that comes down and comes out through the White Bluff substation and is transformed down between 230 and 115 KV and goes onto the Benton substation. If you recall the Benton was our primary source of 115 supply to the back up transformer. Here we see the ring-bus arrangement in Ashe that we draw off the power supply for our starter transformer TRS which we showed you on the tour yesterday.

(Slide)

This shows you the similar arrangement at the Benton substation. Again, we have at least 4 independent sources of supply coming from the hydro project that tie in the supply of 115 KV. Here is the White Bluff's inter-tie that I mentioned from the previous slide. It comes in -- it's an additional source of 115 and comes into the Benton substation.

The important concept that I would like you to understand here is that the ring-bus configuration which would allow us basically -- we have the ring-bus aligned such that we have the circuit breakers between the major load and incoming source to protect our sources from faults on the grid external to our switching station. Should we have a problem should this particular component fail, we have the opportunity to close in a manual disconnect switch loacted here which will bring in again all four sources of supply in the ring-bus configuration into our source of supply.

MR. RAY: I'm confused by your nomenclature. To mek that's not a ring-bus. A normal operation, I gather that the top bus without the switches on it is not closed in, am I right?

MR. POWERS: That's correct.

MR. RAY: Well then, that's a straight bus, really, and the normal operation, the bottom bus is energized and each source is switched to it except your start-up transformer. That's a straight bus. See, you don't have the continuity of service without switching that goes with a ring-bus. Now, it's an academic point, but don't call it a ring-bus if in a normal operation it isn't in the ring configuration. Do you follow me?

MR. POWERS: Yes, I understand your point. I'll attempt to clarify that.

MR. RAY: That's allright. You see, there is an element of reliability. I'm not prepared to give you a quantitative measure of it but there's an element of reliability, additional reliability, if you have a ring-bus rather than a straight bus because if you have a bus fault there, you lose every connection to it. Every source as well as every load and you're out until you switch back in the bus at the top. Do you follow me? And the ring-bus, this isn't necessarily true. You may get a fault between breakers. It's cleared and everything on the bus except what was connected to that section is still in service. So when you call it a ring bus, you're giving it a connotation of additional reliability over what that represents. And it isn't correct.

MR. POWERS: I think there may be -- I'm pretty confident that we have a ring bus arrangement. I think there may be a problem with the simplified diagram that I've got up here. I'm very confident --

MR. RAY: If this is correct, whatever presentation you make or whatever you publish, don't call it a ring-bus.

MR. POWERS: I understand your concern and again I'll clarify that as quickly as I can.

(Slide)

What this particular slide is attempting to show is the immediate vicinity of WNP-2 and the incoming and outgoing sources of supply. Very quickly, I have the reactor building here and the turbine building and I have the switch yard indicated, encircled in the fence.

Our normal source of supply for the emergency buses which are depicted here as SM 7 and 8, would come from TR-M 3 and 4 which are normal auxiliary transformers which take a feed off of our generator output and supply normal source of power through SM-1 and 2 to SM-7 and 8.

In addition to that, we ahve the incoming start-up transformer located here that has a 230KV supply again coming from the Ashe substation. In addition to that we have the back-up auxiliary power transformer located here which has switching mechanism that will directly supply power to the critical buses, SM-7 and 8 and it's source of power as I said before was the Benton substation. It comes in at 115 KV.

MR. EBERSOLE: Let me ask you a question. It's kind of a fundamental one. You've got other plants coming on, TWRs and so forth and some of them really don't want to transfer after they get a generator trip. They want to maintain the output of the generators to service the reactor cooler pump for awhile on the grounds that a certain kind of transient might have preceeded the closure that is, the trip out of the turbine. This tends to raise a kind of fundamental question. Why is it advantageous in the first place to run the auxiliaries of a nuclear plant off the output of it's own turbine generator rather than maintain such auxiliaries through station service systems and not be faced with the necessity of the switch which is inevitable every time the turbine generator comes down. My understanding is, that I -- I asked TVA this question and they are going to henceforth do this beginning at Bellafont. They will no longer carry the unit auxiliaries off the turbine generator output. They'll carry it off of another source. Therefore, there'll be no switching. Is this just a historical way of doing things from the fossil and hydro days and we keep doing it this way or is there a distinct advantage in your view of running off the unit which is sure to go dead when you get in trouble?

MR. POWERS: I'm not prepared to conjecture about the long term or the background of why we evolved into this particular kind --

MR. EBERSOLE: Looking further down the road, you might raise the question. Why do I always jump to the unit for it's own support when I'm going to need it worse when I don't have it. It's not the coal miners and the hydros. I got to have it when I'm not running and it doesn't fit any more. Well, it's just pertinent to the distribution design here. Maybe in the future.

MR. POWERS: As I indicated yesterday to you, Mr. Ebersole, it would be a simple matter of us closing the TRS breakers --

MR. EBERSOLE: You could get it.

MR. POWERS: And opening the normal auxiliary breakers and running with our normal house loads carried off of the TRS.

MR. EBERSOLE: The question is, why do you even have to do that?

MR. RAY: Chris, is the capacity of the back-up transformer the same as your unit -- station transformer?

MR. POWERS: There is a rating difference.

MR. RAY: Then I presume that the loads that would be switched onto the back up source are essentially the safety loads.

MR. POWERS: That's correct.

MR. RAY: Rather than the general loads.

MR. POWERS: That is correct.

MR. RAY: Okay, thank you.

MR. EBERSOLE: Chris, since I seem to have an infinite source of information in front of me, I'm going to pull on it. What is the -- in the event of a turbine generator disconnect where it loses it's main load and has only house load left what's the reliability that you might quote to me that you will guarantee loss of exitation? That you must have it? You've got to have it? I don't want a persistence of voltage at the unit transformer. I want it to die and the reason I'm doing that is, if I don't have a reliable way of doing that, I have a potential of over speed on the house load.

MR. POWERS: The loads that we're primarily concerned with, Mr. Ebersole, all are critical components required for shut down. They are powered off SM-7 and 8. We have two levels of under voltage protection on those buses that since both an instantaneous under voltage of 69%, we also have an additional back-up -- perhaps I shouldn't say back-up because the set point is higher, but we have a sustained 83% under voltage trip where you don't degrade to less than 69 but it's a time delay, 8 second trip on -- continued degraded under voltage on the -- at 83% on the emergency buses. We have two levels of under voltage protection on the critical bus.

MR. EBERSOLE: Oh, you clear these by breakers?

MR. POWERS: Yes.

MR. EBERSOLE: So you don't have as a for instance, the main cooling pump still hung on the output of the turbine generator?

MR. POWERS: No, they're not. When we receive a turbine trip, we use our power supply to, in this case SH 5 and 6 which are the 69KV supplies to the recirculation pumps.

MR. EBERSOLE: Do you understand what I'm getting at? I do not want to have a persistence of voltage output at high frequency.

MR. POWERS: Yes, we recognize that and have so made design changes to protect, and our desire here was to protect the ECCS equipment.

(Slide)

This particular slide now provides some additional detail of the power distribution system within the plant. Very quickly, this is our main generator, our step up transformer from 25 KV to 500 KV and we transmit the out-out of the generator onto Ashe and the 500 KV distribution system.

In addition to that, we have TR-N1 which is our unit auxiliary transformer that steps down the 25KV output from the generator to the 4160 volt supply that comes through SM-3 down to SM-8 which is our critical division 2 bus. That it would be the normal line up as we are operating, possibly would currently call for us to line up.

In addition to that, in periods of time when we do not have the generator, we use the start up transformer here coming in again, 230KV coming from Ashe. It is set down to 4160 volts, comes again through SM-3 down to SM-8.

In addition, we have the back-up transformer which has as it's source again coming from Benton, 115 KV stepped down to 4160 that comes in and can directly SM-8.

In addition to that, we have a diesel generator system that can supply necessary power to SM-8. So in summary, we have 4 sources of power to the critical buses. We have the normal unit, TRS and TRV as will as the diesel generators.

Now, to address your question, Mr. Ebersole on why we couldn't normally line up to supply the -- normally have TRS as opposed to relying on our unit, all we would have to do in that case would be to open that breaker and close that breaker.

MR. EBERSOLE: My basic question is why is that the normal load?

MR. POWERS: I guess I'm not prepared to address our philosophy in that regard.

MR. EBERSOLE: And SM-7 is the same?

MR. POWERS: That's correct.

MR. EBERSOLE: Opposite hands.

MR. POWERS: I have chosen to highlight Division 2. Division 1 which is SM-7 located here is identical.

MR. EBERSOLE: What prohibits are there on the inter-tie? You have a tie bus.

MR. POWERS: These two breakers are mechanically interlocked. Excuse me. These two breakers are interlocked logically from closing at the same time.

MR. EBERSOLE: That's just electric.

MR. POWERS: That's correct.

MR. EBERSOLE: Can a single failure inter-tie those buses and get the diesels to fail because of non-synchronization? When I hear interlock I think of one circuit affecting two breakers. Can I find a single point in the interlock that I can punch and make an out of phase connection to the diesels?

MR. RAY: Are you sure, Mr. Powers, that it's only a logic interlock -- that there is not a mechanical interlock?

MR. EBERSOLE: I believe it would take a long bar, Jerry.

MR. RAY: It depends on how close they are.

MR. POWERS: I don't believe that there is a mechanical interlock between the two. The two buses are physically separated.

MR. RAY: Physically, why, why are they separated?

MR. EBERSOLE: In general, when I hear the word Interlock is it not proper for me to infer that that is a single circuit inter-tying to other electrical elements and in that circuit, I might have a single failure which involves both of the others? And you know, what appears to be redundant is really single tracked?

MR. RAY: There's always a possibility of an interaction between control elements that --

MR. EBERSOLE: Well, it would be not nice to have an inadvertent non-synchronization tie of these diesels when they were needed.

MR. POWERS: Let me see if I can close this particular question.

MR. MEADE: My name is Terry Meade. I'm engineering plant staff. Will you repeat your question, please?

MR. EBERSOLE: Is there in the bus tie interlocking system which ties two breakers together and therefore prevents non-synchronized inter-ties of the diesels, is there a single point in that circuitry which I could go fiddle with and cause an out of synchronization closure with those breakers.

MR. MEADE: No, there is not. They're interlocked via A contacts on the circuit breakers.

MR. EBERSOLE: A contacts.

MR. MEADE: A contacts. They'll be closed. A contacts indicate that they will be closed when that particular breaker is closed. The other breaker has in it's circuitry interlocked to that contact and the other one has the same system. They are not tied together at any point.

MR. EBERSOLE: So you just -- go to auxiliary switches on the breaker?

MR. MEADE: That's correct.

MR. EBERSOLE: Can I devise a short-circuit in the wires that will defeat that logic?

MR. MEADE: If you had a jumper wire, you could possibly do that.

MR. EBERSOLE: I don't mean a jumper. I mean a wire to wire fault.

MR. MEADE: No, I do not believe so.

MR. EBERSOLE: You can't do it with a wire to wire fault?

MR. MEADE: I do not believe you can.

MR. EBERSOLE: Okay, well, I'll drop that for the moment.

MR. NELSON: Thanks very much.

MR. EBERSOLE: Thank you.

MR. RAY: Before you go on to the DC system, I have a couple of general questions. One, I think we learned yesterday that the transmission system into which whip speeds is operated by Bonneville and what you said this morning would imply the same thing.

MR. POWERS: That is correct.

MR. RAY: So therefore the switching at Ashe including this unit switching is under the control of the Bonneville system operator?

MR. POWERS: That is correct.

MR. RAY: In the event that you should have, as incredible as it may seem, an AC system black-out, particularly the 500 KV, or the 230KV, is there any priority agreement as to priority assigned by the Bonneville system operator for restoration of AC supply into whips?

MR. POWERS: Yes, we do. There are at present two nuclear stations on the BPA grid that being Trojan and in the very near future, the unit 2. We have if you'll recall from my first slide, we have major inter-ties between the mid-Columbia and upper-Columbia as well as the lower Snake hydro projects. We have an agreement with the Bonneville Power Administration that we would have top priority for power restoration.

MR. RAY: Good. The other question, do you know if Bonneville has made a transient stability system analyses involving whips operation? That is, for instance --

MR. POWERS: Should we trip off 1100 megawatts from their grid?

MR. RAY: I beg your pardon?

MR. POWERS: Should we trip off 1100 megawatts from the grid?

MR. RAY: No, but you may not be able to prevent it. If you have a bad enough fault, it may be that this unit goes unstable and trips.

MR. POWERS: That is a distinct possibility.

MR. RAY: Unless they've analyzed it and found that that won't happen for the worst fault on the system. Do you know if they've done that?

MR. MARKOWSKI: May I answer this one?

MR. RAY: Yes.

MR. MARKOWSKI: Franz Markowski, system design engineer. I have talked to three different Bonneville people in the course of retrieving grid reliability data from Bonneville and I have asked them this very question and they have a group working on stability analysis continuously.

MR. RAY: I would expect that.

MR. MARKOWSKI: Yes, they have looked at this problem.

MR. RAY: And they're satisfied that for the worst fault condition on the 500 KV system, the WNP-2 stays in service? It does not go unstable?

MR. MARKOWSKI: It does not go -- yes, the stability question is what they particularly look at.

MR. RAY: And it's affirmative that it's a stable situation?

MR. MARKOWSKI: Yes, that is correct. And this is a continous effort, this is not a one shut task.

MR. RAY: No. Any time a major change is made in transmission connections or source connections to such a system, the stability study should be made and a good organization like Bonneville would certainly make it. But I wanted to make sure that they have done it for this unit.

MR. MARKOWSKI: Right, they have.

MR. RAY: Thank you.

MR. POWERS: What I have before you at the present time is a schematic of a 250 volt DC distribution system.

(Slide)

This is the 250 volt DC distribution panel depicted here with the station, 250 volt batteries riding on, normally riding on the bus. In addition to that, we have a 250 volt battery charger that is continuously maintaining a battery charge. In addition, it is the normal source of supply, if you will for the 250 volt DC loads. The division one power supply comes ultimately from SM-7 which is a critical bus, as I indicated previously, that has 4 sources of supply to it.

What we have depicted here are typical loads off of the 250 volt DC system. Here's a typical motor operated valve starter. Here's a typical motor starter. Some of the loads off of the 250 volt DC system include the RCIC system valves, the reactor head spray valve, the reactor water clean up outboard isolation valve, but primarily there are the RCIC system valves are powered off of the 250 volt division 1 DC bus.

(Slide)

I wanted to show a similar arrangement for a 125 volt DC distribution system. Again, we have the same arrangement and we have the batteries on the distribution panel. Normally, a battery charger -- again, ultimately powered back up through a series of switching arrangements back up to SM-7 which is our critical bus, again, with four sources of power to it. Some of the typical loads off of this particular instrument or excuse me, this particular distribution panel are, the diesel generator control circuitry, the switch gear logic, and the inverters that supply the critical instrument buses that provide the power for our critical instrumentation in the control room.

MR. EBERSOLE: Does the high pressure core spray and the RCIC DC controls come off of separate DC buses?

MR. POWERS: The high pressure core spray system has a -- it has it's own DC system.

MR. EBERSOLE: Has it's own DC -- okay, thank you.

MR. POWERS: And therefore they're on diverse systems.

MR. EBERSOLE: If I were to hypothesize that the battery voltage regulators in their modulation mode got stuck at maximum voltage, what would be the terminal voltage obtainable on this, on say the 250 volt bus? Would it be like 280 or 290 or 300 or --

MR. POWERS: I'm not sure but I'll try to get you a direct answer.

MR. EBERSOLE: The point is, I'm trying to find out where there is a nail in the modulation control. Another way of asking this is, when I -- well, if I'm equalizing the charge on the batteries, do I leave the loads on this -- on these DC buses? Are they qualified for the highest voltage necessary to equalize the charges? You're on a periodic equalization charge. Do you do so with the loads in their normal connected mode?

MR. POWERS: Yes, they do.

MR. EBERSOLE: So they take the saturation voltage level.

MR. POWERS: Yes, they do.

MR. EBERSOLE: If I accidentally lose the battery, do I have any stabilization problems with the charger? Will it carry the DC loads without the stabilizing influence of the battery?

MR. POWERS: Yes, it will. Yes, our normal power flow, if you will if you can imagine it, is down through the charger and up through the loads.

MR. EBERSOLE: And it doesn't need the battery?

MR. POWERS: The batteries are just riding on the --

MR. EBERSOLE: Right, it doesn't need the battery to assist in the regulation. Thank you.

MR. RAY: Mr. Powers, before you go on.

MR. POWERS: Yes.

MR. RAY: Have you evaluated how long you can run on DC without AC supply into the station?

MR. POWERS: Yes, we have. I'll be addressing that in more detail in a little while when I get on with the presentation.

MR. RAY: You will. Thank you.

MR. POWERS: What I have here is Division 1 of the 24 volt DC system that we have. Typical loads off of this particular system are exclusively our neutron monitoring system. Again, the power supply, ultimately if you trace this particular source of power back to the -- it's a source for Division one. It also cascades back to SM-7 which is our critical bus. We have Division 1 SRMs and Division 1 IRms powered from this 24 volt DC power supply.

DR. PLESSET: Well, let me make a comment here. I think when you go to the full Committee, you can omit this presentation.

MR. POWERS: This level of detail?

DR. PLESSET: But be prepared with the material, all right?

MR. NELSON: Omit this presentation but be prepared with the material.

DR. PLESSET: In case there are questions on it. I think this part they might be interested in. They may not believe it but they'd like to --

MR. EBERSOLE: The first reaction to numbers like this is whoever analyzed it never heard of common mode failure. When you get past 10^{-4} and 10^{-5} everything gets very shady.

MR. POWERS: I'd like to point out that this is a plant specific analysis that we have conducted for our unit. Some of the information that is included in here comes from an analysis that we submitted on our, for our 1 and 4 projects because much of the information is common between the two units. What I've got this slide up here for is the probability of events per year of losing all AC for longer than the appropriate times as indicated. The point I would like to make here is that we think that it's highly incredible to assume that we lose all of our AC power supply for longer than 120 minutes.

DR. PLESSET: A new definition of incredible.

MR. POWERS: Yes. I believe the standard industry is on the order of 10^{-4} or 10^{-5} and we're down several orders of magnitude beyond that. I feel very strongly that because we are on a hydro -- we're on a very significant hydro grid with 27 hydro projects each with self-start capability, that the probability of our losing RHC for longer than 120 minutes is extremely remote.

MR. RAY: I would agree that it looks like that. Have you talked to Bonneville about time for restoration?

MR. POWERS: Yes, we have.

MR. RAY: And they say they can do it in two hours?

MR. POWERS: These numbers have in them studies from the Bonneville Power Administration on their mean time between failures and the length of outages that they have experienced to date in the 35 plus years of the power distribution business.

MR. EBERSOLE: Chris, let me call your attention to the earlier presentation on the probability of exceedance of the earthquake that you expect. The numbers like 10^{-4}. Incidentally, what is this? Probability for what?

MR. POWERS: Events per year.

MR. EBERSOLE: Per year. The other was also. And the probability of exceedance of the design basis earthquake as I recall is 10^{-4} which invalidates these numbers immediately. I mean, you've got to look broadly when you create numbers like this. Look back at the earthquake and they say these are no good.

MR. POWERS: I'm not sure that's a logical conclusion, Mr. Ebersole.

MR. EBERSOLE: Isn't it? Well, the off-site power system is not seismically competent, is it? And the turbine generator is not at all.

MR. POWERS: Certainly the turbine generator is not.

MR. EBERSOLE: Neither are the towers.

MR. RAY: I don't think that the industry yet builds earthquake proof transmission lines.

DR. LIPINSKI: Well, let me ask the question -- I wanted to ask this yesterday when we were in the switch yard and we saw those tall, vertical ceramic insulators that fed the main transformers. What rating do they have for G forces?

MR. POWERS: I'm certainly not prepared to answer that question.

MR. RAY: Well, I don't think is specific with WNP-2. It seems we're talking generic things.

MR. EBERSOLE: But the fellow who turns out these numbers certainly doesn't work with the earthquake team.

MR. MEADE: I think I should point out here that these figures include both loss of off-site AC and loss of on-site AC.

MR. EBERSOLE: Yes, I know that, right, so that brings in the 99% reliability of the diesels.

MR. MEADE: Yes, we did not use a .01 factor, but as far as orders of magnitude, yes, that's right.

MR. RAY: He wouldn't have believed that either.

DR. LAPINSKI: With no common mode on the diesels you get 10^{-4}.

MR. EBERSOLE: Well, one looks at these numbers with a kind of a you know, degree of suspicion.

MR. RAY: You have to commend your courage, though, in citing them.

MR. POWERS: Are there any further questions on the AC distribution? What I would like to do now is provide a brief description of a total loss of AC incident. How we would expect to respond to it to provide you some assurance that we feel comfortable that under these circumstances that we could adequately mitigate the consequences of this particular incident.

(Slide)

What I'd like to do first is discuss the plant transient, starting out with the first two items there, form the basic assumption of the scenario under which we are going to proceed. First of all, I assume that for some particular reason, if I lose both the 230KV and the 115KV AC sources concurrent with failure to start of the on-site diesel generators. In addition to that, I also assume that whatever the major grid disruption was that caused me to lose both the 230KV and 115 will create a turbine trip and I've lost the main generator and my ability to carry house loads from our own generator.

Almost---instantaneously we would expect to experience a reactor scram and a primary containment isolation as a result of the turbine generator trip and the loss of all of our AC power. Very quickly thereafter reactor pressure begins to rise rather rapidly and reaches a safety relief valve set points whereby the relief valves would open to relieve reactor pressure transients.

Reactor water level would begin to decrease because we lost our feed supply yet we are relieving pressure through the relief valve so that water level would begin to decrease. At the point where we reach a level 2 as we call it which is -38 inches from normal water level, from instrument zero on the narrow range, we would experience an RCIC system initiation and RCIC would start and begin vessel injection some 30 seconds after it received it's initiation signal.

MR. RAY: What's the drive on the RCIC?

MR. POWERS: What is the drive? The steam from the reactor. RCIC takes the steam supply when it comes off the main steam line which, the tap point is between the reactor vessel and the in board isolation valve. So, that on a containment isolation we would still maintain steam support.

MR. EBERSOLE: In view of the relatively low reliability of the RCIC system, with all of it's auxiliaries, I should think you would claim title to the electrically driven diesel high pressure core spray as not being a part of the electrical network. I think you could claim that.

MR. POWERS: The HPCS system is an entirely separate redundant or entirely separate electrical system.

MR. EBERSOLE: Certainly, there's an element of common mode significance, if they all have got the wrong fuel or something.

MR. POWERS: Yes, the impact of that, assuming that we have HPCS -- is that we have a water level transient that is less severe. The conclusion would still be the same, however which I will draw in a minute and that is, that the water level never reaches the top of active fuel and we provide adequate core cooling on that basis.

Approximately 10 minutes after the isolation, assuming the expected decay heat load approximately 10 minutes after isolation, the RCIC system capacity will have caught up with the steam relieving rate and begin to turn water level around. And in a matter of a few moments, RCIC will return water level into it's normal band whereupon the reactor operator would take the RCIC system and control water level in the normal band -- the point I want to make here is that level remains at all times above top of active fuel.

MR. EBERSOLE: Chris, could you tell me, in the beginning of this transient, how many safety reliefs would have opened?

MR. POWERS: Depending on when this transient occurred --

MR. EBERSOLE: At full loads is the best case.

MR. POWERS: Depending again on what cycle we're operating in. If we're out in the equilibrium cycle, we expect to -- we would expect to lift three to four pressured relief groups which would be approximately 12 of the 16 total relief valves that we have.

MR. EBERSOLE: If one of them sticks open as has been our experience with them, are you in trouble?

MR. POWERS: Our feeling on that subject is no, we would not. We would experience a lower minimum reactor water level but relatively quickly into this transient, the RCIC capacity would exceed the safety relief valve discharge capacity and return water level to near normal. It would take us a longer period of time to do that.

MR. EBERSOLE: Would you eventually run out of steam pressures so you couldn't run the RCIC?

MR. POWERS: That is a distinct possibility, yes.

MR. EBERSOLE: And that's where the diesel driven core spray is your main frame (ph)?

MR. POWERS: That is correct.

I'd like to point out that our critical plant instrumentation and logic would be available from both the two divisions of 125 volt DC as well as we'd maintain control of the appropriate valves on RCIC through the 250 volt DC system.

Continued relief valve operation in this mode would begin to raise pool temperature. In conjunction with that, our loss of drywell cooling because we've lost AC, would also cause containment temperature to increase. Associated with that,containment pressure would also begin to increase. However, for the initial portion of the transient, we would -- in a matter of minutes, have reactor pressure and level under control. Therefore, we have adequate core cooling in that scenario.

Now there are some mitigating actions that as operators of the plant would have to take in order to maintain an acceptable plant response to this particular scenario and I would like to summarize those briefly.

We have some primary containment integrity protection emergency procedures that would direct us to take action to protect primary containment integrity any time that the suppression pool temperature is elevated at the same time that we have significant pressure in the reactor. Should we go beyond the heat capacity of the suppression pool, we would be directed by those procedures to rapidly depressurize the vessel and maintain it depressurized. In that situation we would depressurize to approximately 100 pounds, such that we would maintain the operability of the RCIC system. RCIC system would isolate 50 pounds reactor pressure.

Immediately upon recognition that we have lost AC power, we would begin immediate action to restore AC power as quickly as possible. There are a number of actions that the operator must take in order to maintain RCIC operability. Some of those would include in the very long term, taking manual action to preclude the leakage detection that's applied to RCIC system from actuating and isolating a system. That would involve jumpering (ph) things like high room area temperature, high turbine exhaust pressure because our containment pressure is increasing, those sorts of measures that we have identified.

The concern is raised about how long we can operate without a source of supply to the DC loads. The operators have identified non-critical DC loads on the buses and we would take action to shed those buses to maximize the length of time that we would have DC power on the batteries.

There is a potential that we would have, in long term line ups that we would have to provide for continued safety relief valve actuation capability and I believe we have a unique design in that regard in that we have on the containment instrument air system, we have normally writing on that system, approximately 16 nitrogen bottles that would supply motive air to, for us to be able to actuate the safety relief valves. If we get beyond that capacity ---- we have the ability to connect directly into the containment instrument air system from outside the reactor building with an external source of nitrogen and continue to supply nitrogen to the safety relief valves.

MR. EBERSOLE: Still through the solenoid (ph) valves, though?

MR. POWERS: That is correct, that is correct.

MR. RAY: Chris, you mentioned that an analyses had been made to determine what the maximum time of operation of the batteries could be without recharging. Do you know what that is?

MR. POWERS: Our design basis is, on maximum load, our batteries are rated for more than two hours.

MR. RAY: No, I mean with only, with the non-critical load shed?

MR. POWERS: With non-critical loads, we are talking on the order of 8 to 10 hours minimum.

MR. RAY: Which would certainly be ample time to restore the AC system.

MR. POWERS: We feel that way yes, that's correct.

MR. RAY: In fact, under those circumstances if you went the 8 hours, you could still bring a source in, gas driven, gasoline driven charger to drive AC through the charger for the batteries.

MR. POWERS: That is correct.

MR. RAY: You're certainly not going to sit and wring your hands.

MR. POWERS: No, that's certainly not the case. I might also point out at this point in time that there are some additional measures that are concerns that we have in terms of maintaining the RCIC system operability and that has to do with the loss of room coolant to the RCIC system and we believe that we can maintain adequate room cooling for a minimum of 2 to 3 hours simply on the natural circulation that would be -- or natural convection that would be established by circulating the reactor building air volume through the RCIC room; should we go beyond that, we can again bring in portable DC or portable generators in supply portable room cooling to the RCIC system.

MR. EBERSOLE: Chris, it seems to me that this all hinges on two basic things. That is, you hold -- well one thing really. You hold from 150 pounds pressure in the reactor because that's what you need to run the RCIC.

MR. POWERS: That's correct.

MR. EBERSOLE: Way back many years ago, the stand-by cooling system was a different thing than you call it. It was a terminal way to get water into the reactor from a brass nozzle or some place via the usual piping channels. You don't have anything like that here. I understand you're a graduate of Brown's Ferry?

MR. POWERS: That is correct.

MR. EBERSOLE: And you recall that low pressure system that was the ultimate flutter? I don't see that here, is that correct? There is no way to get water in at about 200 pounds from some totally external source, having nothing to do with this unit, like domestic water or city water?

MR. POWERS: We have an interconnection from the stand-by service water system that we can directly, through the tower make up system located at the river, would be the normal supply for -- I shouldn't say normal but, would be the installed capacity to inject river water directly into the reactor.

MR. EBERSOLE: Oh, you do have such a --

MR. POWERS: We have a connection on a stand-by service water system, yes, that would allow us to by-pass or take the stand-by service water system and eject directly into the core.

MR. EBERSOLE: I see, and what powers that?

MR. POWERS: Our normal supply of AC.

MR. EBERSOLE: So that goes back.

MR. POWERS: That is correct.

MR. EBERSOLE: You don't have another nuclear unit some place? Or another AC power supply for this plant? You just listed all of them.

MR. POWERS: That's correct.

MR. EBERSOLE: I just want to understand that that system is not here.

MR. POWERS: I'm informed that we also have a diesel driven fire pump that we can inject -- cross-connect from the circ water system into the stand-by service water system which would then allow us to go into the reactor.

MR. EBERSOLE: Well fine, you found it.

(Slide)

MR. POWERS: I think in summary what we'd like to say on this particular subject is, that because of our unique situation, we have confidence in our loss of AC numbers. We believe that the total loss of AC for longer than two hours is absolutely incredible. We have a very strong hydro based system on which we can isolate the output of each dam. We have a multiple flow path of hydro--we have multiple flow paths of power into either the Benton or the Midway substation to supply power to our unit. Each of those hydro stations has a self-start capability. In addition, we have a very high priority within the Bonneville Power Administration to restore that power to us. We feel comfortable that we would restore power within two hours. In addition to that, we have adequate emergency procedures that would prescribe for us mitigating actions that we can continue to operate, certainly beyond two hours as we have discussed here, and so we feel we're adequately designed to survive the loss of AC.

(Slide)

The last subject I'd like to discuss very quickly is some modifications we have made to the remote shut down system to provide us with an alternate remote shut down capability or a redundant remote shut down capability.

We are in the process at the present time of implementing design changes to the plant that would provide for us local control switches and equipment status lights at localized motor control centers to provide for operation of critical pumps and valves such that we can light the A RHR system up in the alternate shut down cooling mode which Mr. Corcoran described to you previously. In addition to that, we would provide local control in status indication such that we can operate the safety relief valves. We would also provide local instrumentation to monitor containment parameters and stand-by service water flows and in this fashion, we feel like we can adequately control reactor pressure level and bring the plant to cold shut down using the A RHR system from a location that's independent of both the control room and the remote shut down panel.

(Slide)

What I wanted to show you basically here was a concept which shows that we have two alternate paths to achieve cold shut down. On the left, we have the normally presently installed design that has control from the control room through the remote shut down panel of the BRHR system. In addition, as I said before we are implementing modifications to the plant design that would allow us to control the other loop of RHR via the alternate shut down cooling mode to get to cold shut down.

In summary, the ultimate shut down cooling mode of operation is approved and is in our licensing basis. We feel that the proposed modifications that we are about to implement provides us an adequate control of that shut down cooling capability and therefore, we provide the ability to have a redundant remote shut down capability.

Are there any further questions of me?

DR. PLESSET: Thank you, Mr. Powers. We'll go on.

MR. POWERS: Thank you. Our next presenter will be Dave Evans who is the program manager for fire protection engineering on Unit Two. He comes to us with over 10 years fire protection engineering experience. Mr. Evans?

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MR. EVANS: Good afternoon. In the interest of holding to the time schedule, I'm going to try to speak rather quickly as far as my part of the presentation. If I go too fast, please ask me to slow down.

(Slide)

Under the fire protection, the WNP-2 position is that the fire protection evaluation report, or fire hazards analysis documents compliance with BTP APCSB 9.5-1 Appendix A and 10CFR 50 Appedix R. These were provided to the NRC as Amendment 19 to the FSAR in October of 81, and Amendment 24 to the FSAR of May 82.

The objective of the fire hazards analysis was to assure that a fire will not adversely affect the ability to bring the plant to a safe shutdown condition or result in a significant release of radioactivity to the environment. The first step of this analysis was to divide the plant into a number of fire areas. This considered all buildings and fires that could have a potential impact on safety.

(Slide)

For each of these areas, we identified barriers that define the area, safety related equipment in the area, consequences of a design basis fire, design criteria for fire protection of safety-related equipment and cabling in the area, consequences of a fire in fire protection systems function as designed, radioactive material contained in the area, type, quantity and characteristics of combustible materials in the area. This also included transient combustibles. Fire loadings which represent those combustibles were calculated. Extinguish and detection and alarm capabilities in the area were identified. A means for containing and inhibiting progress of fire in the area was identified. Extinguish and detection alarm equipment outside, but with access to the area, was culled out. An Appendix R evaluation was performed for each area and indicated the capability of plant division components to achieve reactor shutdown and maintain core cooling was not lost.

The result of the evaluation was the cabling components were identified which required analysis and protection. All safety-related systems have been separated for unacceptable fire hazards through remote separation or barriers to the extent that is possible. Redundant safety-related equipment has been located such that it is either in separate fire areas or separated to prevent damage from a single fire hazard. Each fire area is individually evaluated in accordance with the requirements of Appendix R. Divisional fire areas such as pump rooms, diesel generator bays sent or assigned to one of the major electrical separation divisions 1, 2 or 3. Analysis then verifies that there are no intruding cables or equipment, in other words, not compatible with the fire area divisional assignment in the area. Or that fire-induced failures and any intruding equipment or cables does not impact capability of those redundant divisions to achieve safe shutdown. Where analysis indicates the intruding cables or equipment can not be lost, protection is provided. General fire areas, open floor areas, etc. are reviewed to determine if they contain any cables or equipment of an alternative safe shutdown system. Any alternative safe shutdown system equipment or cables located in the fire area is protected from the fire.

(Slide)

Major factors that ensure defense in depth are a passive fire prevention/protection measures. These are mostly 3Hour rated walls, floors, ceilings, doors, etc. We also use one or three hour rated cable envelopes for required safe shutdown within the sphere of the possible exposure fire. Use of a three hour envelope is unique to the supply system. In our recent test program which I have slide presentation I'll show later.

We also have administrative control of combustibles and ignition sources. For the fire water system, we have redundant water storage facilities, redundant pumps, redundant flow paths.

For the water fire suppression systems, we utilize preaction systems with our supervision on the piping and most safety related areas with comparatively high fire loading.

This type minimizes accidental discharge and water damage. Small manual spray systems and safety-related charcoal filter units are provided, but we do have redundant units available if an accidental discharge should occur. But these are manual systems.

Standpipe hose systems, we have multiple standpipes in each building. These are valved to prevent loss of two standpipes, or a standpipe and a major suppression system. Under gaseous fire suppression systems, we have no gaseous systems in occupied safety-related areas. We use Haylon 1301 in the PGCC subfloor sections for protection in the control room.

For the fire detection system, the detection system is the prealarm concept with an alarm in the control room. In addition, activation of a suppression system or a manual station initiates control room and building-wide alarms. Most suppression systems have detection systems independent of the prealarm system.

For component reliability, we have maximum use of equipment tested by National Testing Labs. We have spare parts stocked on site. We utilize complete in situ functional testing performed initially and periodically as required by technical specifications.

As previously covered, we have remote shutdown capability outside the control room. The remote shutdown panel and related components in the remote shutdown room will be able to achieve cold reactor shutdown in the event of a control room fire.

An ongoing fire protection/prevention program includes plant fire and safety coordinators, supply system fire protection engineers, ANI regular inspections, fire-related training in accordance with Appendix R, surveillance and maintenance procedures, administrative controls.

(Slide)

Major fire protections improvements being made by WNP-2 are indicated on this slide. The cable raceway systems protection and test program is the most significant of these improvements as the supply system has sponsored a test program to develop both one and three hour fire rated envelope systems. The three hour envelope would be an alternative to automatic sprinklers, and alternative to one hour fire rated envelope. It is the intent of the Supply System to utilize both alternatives, but to also minimize the use of sprinkler systems by installing the passive three hour fire rated envelope wherever possible, particularly in the reactor building. I have a slide program which I would like to show at this time which illustrates results of that test program. Before I start the slide program, I'll give you a little background on the material.

The Supply System sponsored with TSN Inc. of

St. Louis an engineering test plan to perform fire endurance and impacity D rating in chemical tests on thermolite 330-1 subliming coating envelope system in conjunction with American Nuclear Insurers.

These tests were applicable to all three sites for the Supply System, as we included cables from our sites 1, 2 and 3.

The testing program was conducted in three separate but interrelated phases, and used the materials and processes to be employed in the actual installation of the thermolite systems for the Supply System.

The Phase 1 fire endurance test. This testing phase involved performing one and three hour fire endurance tests, water hose stream tests, and electrical continuity tests. These tests were performed in accordance with American Nuclear Insurers Bulletin No. 579 which is the standard fire endurance envelope for Class 1E electrical circuits. We also performed these in accordance with ASTM E-119, anbd NAP Standard 251, the standard method of fire-tested building construction materials.

The impacity D rating tests consisted of establishing a baseline impacity for power cables installed in an open top cable tray test assembly and then determining the amperage D rating which occurs when the cable tray test assembly is enclosed by a three hour fire endurance envelope and results therefrom. These tests were performed with insulated -- excuse me, these tests were performed in accordance with the Insulated Power Cabling Engineering Association and National Electrical Manufacturers IPCA Standard No. P-54-440, and NEMA Standard No. WC-51-1975.

We also performed chemical properties tests. These involve performing infrared spectraphotometry, pH of gaseous effluents when mixed with water and flammabilities of condensibles.

The acceptance of the fire endurance test was based on the criteria of the American Nuclear Insurers under their test program. The current status of the test reports that were perpared as a result of those tests: the one hour report has been accepted by the American Nuclear Insurers, is presently under review by the NRC. The three hour report is currently under review by ANI, and we hear to date that the results of that are going to be favorable. I'll go to the slide program at this time.

(Slide)

What you see here is the three hour test. This is typical in many ways of what we did for the one hour test also. Here you see our test sample No. 6 coming out of the furnace.

(Slide)

These furnace temperatures at the end of the three hour periods were averaging 1925 degrees fahrenheit, but yet we were able to maintain internal temperatures at the highest thermocouple reading of between 240 degrees and 328 degrees fahrenheit. Those were the highest readings. The average would have been much lower.

(Slide)

What you see here is the sample being moved into the hose test booth. The hose stream test then impacted the specimen giving you thermal and mechanical shock.

(Slide)

You see here the results of this particular specimen, in this case, it was conduit, but this is typical of the tray samples also.

(Slide)

You can see the relative amount of impact of the hose stream where it stripped away material. One of the criteria we had to meet was that we maintained continuity on the circuitry during these tests, also during -- I mean, during the fire tests and the water stream tests. We had to maintain continuity with no faulting. This was successful in all tests.

(Slide)

Here you see Test Number One, a three hour tray sample. We cut this open here to show the end, cut it open at the top to show repair patch.

(Slide)

Here is a closeup of the end view on Test 1. Note the undamaged cables.

(Slide)

Here's a closeup of the repair patch to show the undamaged cables. Note the undamaged nylon cable tie here.

(Slide)

This is Test No. 3 and 5. This combined a tray with an airdrop cable. Here it's been cut open to show an end view of the results. The top section cut open, and down here I'll show you a closeup of the free drop cable here and the results of thaat.

(Slide)

Here is the top cut open. Notice the undamaged cable. All continuity was maintained, no faulting. Again, temperatures never even reached the point where we damaged the nylon cable tie.

(Slide)

Here is the airdrop cable. Note that even the electricians tape that was used to hold a thermocouple wiring in place was not damaged.

(Slide)

Here's a closeup of that.

(Slide)

This last slide shows the Test 3 and 5 end view

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as part of the assembly. For whatever reason, there was some masking tape that was used for notations like that that happened to get left in there. And notice that the masking tape is not even damaged.

(Slide)

These are the cables or nylon ties.

This ends the slide program.

MR. MATLOCK: Is this stuff any good, to you?

MR. EVANS: I think it is.

MR. LIPINSKI: Question. Did your cable tray loading have to be D rated based on the fact that the trays are being wrapped and not exposed to air?

MR. EVANS: As part of our testing program, we took into account impacity D rating. What we did under the impacity D rating portion of the test was perform those tests, as I indicated previously. Our results from that were we had a 17% impacity D rating factor which is quite low compared to alternatives. This was for three hour, which is a one inch thickness of a thermolite material. If you go to the one hour barrier which is a half inch thickness of this thermolite material, it's approximately 12.5% impacity D rating. So as you're well aware, this is primarily affecting power cables, so we're well within the range on our plant of being able to use this material and not running into impacity problems.

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MR. LIPINSKI: Then the D rating also allows you to maintain the same life on the insulation?

MR. EVANS: Yes.

MR. LIPINSKI: And the life of the plant.

MR. EVANS: Yes.

MR. PLESSET: If you hve other points you want to make, why don't you do that?

MR. LIPINSKI: Okay. When we toured the cable spreading room, we saw the fire protection system that was in there. You have the ionization detectors. They turn on the water supply to the headers, but water does not leave until the bimetallic strip melts at the particular point where the fire is located. Now, the spacing on these heads was not uniform, and a reference was made to the fact that a study had been done to determine what the spacing requirements were. Are you prepared with what the study calls for in terms of a maximum spacing between heads in order to offer protection?

MR. EVANS: Yes. The spacing of those heads was established by the consultant that was hired by the sprinkler company who installed them. He went through a hydraulic analysis, evaluated the spray pattern of the heads which is a hemispherical spray pattern, evaluated coverage of them, and positioned the heads accordingly so that they would have spray coverage. I remember one of your areas of concern was near that column, that one head above --

MR. LIPINSKI: Right. Those two heads were quite close together. Next to the column there wasn't a head.

MR. EVANS: Right.

MR. LIPINSKI: The head appeared on the other side of the column.

MR. EVANS: Right. The head appeared on the other side. But we did have the head there right in front of us that could give enough of a side pattern. These won't spray directly ahead. They will spray to the side. So you do have a hemispherical pattern that will encompass the trays as designed.

MR. LIPINSKI: That still doesn't answer my question. What's the maximum spacing between heads that you can accept? I know they're installed, but there had to be a number that was used to guarantee that they were meeting the specifications.

MR. EVANS: Well, a minimum spacing would be in the range of six feet, because if you get below six feet, then you run into the problem of the potential of cooling the fusable element on adjacent heads. The maximum spacing is a function of the tray configuration. If you had a flat ceiling, you could go to a maximum spacing such as say, like on an ordinary hazard area, you can go to 130 square foot spacing. When something is congested as a cable spreading room, it's more of a custom design to the actual configuration of the tray runs. As far as the spacing. It's not a linear type --

MR. LIPINSKI: Well, who did the custom design, your consultant?

MR. EVANS: Yes.

MR. LIPINSKI: He did the custom design for the layout of those spray heads.

MR. EVANS: Yes. And the man that designed that has some twenty years experience in specialized protection.

MR. LIPINSKI: Aren't these the first applications where tray heads are being used on trays, though?

MR. EVANS: Not to my --

MR. LIPINSKI: This is not an old technology.

MR. EVANS: Not to my knowledge, this is. I don't believe this is the first application of spray heads on the cable systems. It's been --

MR. LIPINSKI: This has been done in the electrical industry prior to the -- after the Browns Ferry fire?

MR. EVANS: To my knowledge, it has.

MR. LIPINSKI: Jesse?

MR. EBERSOLE: I don't know. I want to ask another question about the fire protection system, though. Is there a localized control panel that you call the fire protection panel?

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MR. EVANS: The fire protection panel that we have is the three panels that I indicated to you, Mr. Ebersole, in the control room, which is the bank of three panels up there, it's the central control panel.

MR. EBERSOLE: Well, you know we have remote shut-down in consideration of potential losing the control room. Do I have something left after I lose the control room to control the fire suppression equipment?

MR. EVANS: The fire suppression equipment, if that's your concern, is actually controlled by their own subcontrol panels.

MR. EBERSOLE: They don't need that central panel then?

MR. EVANS: No, sir. The central panel receives signals from the prealarm signals such as ionization detectors and like that, but the suppression systems have their own subcontrol panel which controls that suppression system. That panel itself reports to the main control panel.

MR. EBERSOLE: Now I'm going to ask you a kind of a general question. By permission of the staff, the fire control equipment is not seismic in complete. Suppose I inadvertently shake the plant with an earthquake, and everything goes off in the wrong direction. Will that bother the function of any of my critical shutdown equipment?

MR. EVANS: It should not. The majority of the system we're using are the preaction type system which would enable you to have an earthquake like that and -- it takes two different functions to activate the preaction system. You physically have to have either smoke or heat depending on the primary detector to electrically activate the valve controlling that system. That then floods the piping with water. From there you have to individually fuse each sprinkler head to deliver water.

MR. EBERSOLE: So the fusing part would not fail, but the electrical part might.

MR. EVANS: The electrial part might, yes. Because of the relays and obviously the panels with modern boards going from older, sturdier relays to more of the printed circuit boards, it is more susceptible.

MR. EBERSOLE: I'm going to ask you another general question. We find electrical powered switchboards depend on local ambient temperature to judge whether or not the circuits are in overload or not. In short, they have a heater in each breaker -- a lot of them do, this is not motive case for the others -- and they judge against that heat temperature rise with the background of the ambient whether or not the motor at some distant place is running under overload. This makes these boards dependent on ambient to avoid their own tripping. If that ambient runs to about 150 degrees fahrenheit, the board thinks all of its attached

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loads are at overload and starts clearing. Some H&V systems use damper and ducting design based on fusable links that appear to require a higher than 150-odd degree temperature to fuse. Therefore, they would permit ambience to rise in even distant switchboard before they would close, since these are designed to old standards of stopping fire progress not stopping ambient temperature. Do you have a system anywhere in the plant where you wouldn't get an appropriate damper function before you lost the board on the discharge side of that flow system?

MR. EVANS: Okay. If I may summarize your question, I believe that your concern is the passage of heat past a fire damper before the fusable element can operate, and it may have some effect on electronic equipment?

MR. EBERSOLE: Electric or electronics. Right.

MR. EVANS: I believe your primary concern would be our switchgear rooms and our MCC rooms where we would have that type of electronic equipment. All safety-related switchgear and MCC equipment are located in their own rooms with appropriate barriers or fire dampers. All of these rooms have high temperature alarms which alarm at approximately 105 degrees fahrenheit in the control room. The control room operator would then have the ability to operate emergency cooling units that are fed by the RHR. And these would allow you cooling in there even in the event that you did get this occurrence.

MR. EBERSOLE: Oh, you have an override cooling capability in these rooms?

MR. EVANS: That is my understanding, yes.

MR. EBERSOLE: You don't depend on open cycle cooling of the rooms. You have another way of cooling the rooms, unit coolers. Is that what you're saying?

MR. EVANS: Yes.

MR. EBERSOLE: But they're not normally in use?

MR. EVANS: No, they're backup.

MR. EBERSOLE: And they will override the influx of hot air, that's what you're telling me?

MR. EVANS: They would enable you to keep the room at a temperature compatible with the electronic equipment until such time locally that damper would activate.

MR. EBERSOLE: Right. Thank you.

MR. RAY: I'd like to return to Dr. Lipinski's concerns. Did you, by any chance, make any tests of installation of the spray heads that would demonstrate their capability for coverage?

MR. EVANS: The spray heads installed all have UL testing behind them, and documented spray coverages under different pressures of what they can cover, and it was that documented test coverage from Underwriters Laboratories that was used for the basis of design of those heads. We do not individually try to turn them on in the plant because of obvious water damage.

MR. RAY: Okay, but that documented test indicated the adequacy of what you put in?

MR. EVANS: Yes.

MR. RAY: Your installed spacing?

MR. EVANS: Yes.

MR. RAY: Does that help?

MR. LIPINSKI: Unless somebody took a look at each one of those heads and took the standard pattern for that head and made sure the water's going to travel in all directions, then yes to your answer. I assume that this consultant that laid this thing out in detail did that in order to determine whether the spray pattern was adequate.

MR. EVANS: That's correct. The consultant did walk down each area and verify that the system had been installed in accordance with his design. These were also walked down by American Nuclear Insurers' representatives to make sure that -- they had copies of the design also -- to make sure that they complied with their requirements.

(Slide)

Okay. This slide shows NRC concerns in the SER and SSER which involve verification during the site visit later this year of adequacy of unlabeled fire doors, and low fire loading in areas where automatic fire suppression systems are not installed for cable raceway protection in addition to one hour fire rated envelopes. At this site visit, additional data provided by the Supply System is expected to close these two issues.

(Slide)

The next slide indicates an NRC concern regarding the completion of hose standpipe changes before fuel loading. The Supply System presently has a request with the NRC for an extension of time to make the committed changes by the end of the first refueling outage. This would allow a more manageable time frame to accomplish the changes and still maintain plant safety during the modification process.

(Slide)

In summary, the WNP-2 position on the analysis contained a point by point comparison to the BTP APCSB 9.5-1 (Appendix A) and 10CFR50, Appendix R. Full or essential compliance with the NRC reviewers taking into account commitments made by the Supply System. An ongoing analysis will be contingent to insure that any future changes will be evaluated under the fire protection program.

This concludes my presentation. If there are no further questions, I'll introduce the next speaker.

Our next speaker is Mr. Ed Fredenburg, manager of WNP-2 civil structural engineering with a presentation on containment systems. Ed is also the Supply System repretative on the Mark II owners group. Thank you.

(Slide)

MR. FREDENBURG: In the issue of hydrodynamic loads and Mark II containments, this has been around for several years now. This is a generic issue. It affects not only this plant, but other Mark II plants. I believe that several of the members on the subcommittee are somewhat familiar with the issue through participation in fluid dynamics subcommittee meetings and also on hearings in other plants. Therefore, in the interest of maintaining schedule on this presentation and avoiding redundancy, I plan, in this presentation, to focus on those aspects of our plant and our load definitions which differ from what you might have seen before in the generic Mark II program, or in other plants.

First, however, I'll summarize kind of an overview of where we are on this issue. Basically, about seven years ago, seven or eight years ago, 1974, 1975 time period we and other utilities became aware of hydrodynamic loading issues in Mark II containments. Since that time we and other utilities, AE's and the NRC have been involved in a fairly comprehensive program to try to understand these loading phenomena, loading conditions, and to resolve the issue. Part of that effort involved forming an owners group which was used as the basis for evaluating some of this information.

One of the key elements of this program involved conducting tests and evaluating test data from various tests in the U.S. and overseas. The principal test as far as our plant is concerned which formed the basis of both generic and some plant-unique load definitions were the what is called the 4T tests and the 4T CO tests which were funded and conducted by the Mark II owners. These were single downcomer tests conducted down in San Jose.

In addition to that, there were tests run in the -- by the Japan Atomic Energy Research Institute in a facility commonly known as Jaeri. This is a multi-vent facility. It simulates a segment of a Mark II containment.

In addition to that, those tests I've mentioned so far were principally to look at and evaluate loading conditions from loss of coolant type accidents. In addition to that, of course we're concerned about main steam relief valve discharge loads in the pool. And the principal tests which wre used to formulate our load definitions for SRV discharge loads were two in-plant tests, one conducted in the Caorso plant in Italy, and one in the Tokai plant in Japan. From this test data, conservative load definitions have been developed, both generic load definitions and plant-unique load definitions. There are currently no open issues between us and the NRC staff on hydrodynamic loads. The NRC has accepted these load definitions.

Another major element of this program as far as we were concerned involved making extensive modifications in the wet well. To enhance the structural capacity of the plant. And I'll point out some of those in a minute.

The final documentation of plant adequacy will be provided in our final revision of our design assessment report which is an appendix to the FSAR.

In summary or in conclusion on this issue, the hydrodynamic loads are accomodated in the final design of the WNP-2 plant.

(Slide)

This slide indicates just a summary of some of the major modifications that we have made in the wet well. I'd like to briefly point some of them out. One of the major modifications that we made was adding horizontal stiffeners to the steel shell. We replaced our existing downcomer bracing system and added a new downcomer bracing system to accomodate vertical drag loads during the pool swell event. We added pipe supports, a lot of pipe supports and some of the suction lines in the pool. We originally had main steam relief valves discharge lines which came into the wet well through downcomers. They were routed in the outer row of downcomers concentrically all the way down to the pool, terminated in open ended pipes in the pool. When we became aware of the SRV discharge loading problem, it became obvious that we would have to reroute some of these lines to achieve a better distribution of loads in the pool. This is indicated up here -- this is not a very good sketch, but -- now these MSRV discharge lines penetrate the downcomers just below the diaphragm floor slot. They're routed around the pool and now terminate in cross quenchers. Which are supported off the floor.

Because of the pool swell problem, or the pool swell issue, some of the structures which were in the pool swell impact zone were either relocated or removed. One example of that was we used to have a catwalk around the pool about six feet above the pool level. This was taken out except in a local area in the immediate vicinity of the equipment hatch which provides access to the pool. Also, vacuum breakers which are mounted on the downcomers originally were mounted at a lower elevation on the downcomers. They happen to be in or near the pool swell impact zone. Consequently they were relocated up at a higher elevation to get them out of the pool swell impact zone.

(Slide)

Those are some of the principal design changes that were made. I want to point out some of the features of our containment which differ from the other domestic Mark II plants. One I think I've mentioned is we have a free standing steel containment, an inclined pool bottom, and cross quencher devices on the end of the SRV discharge lines. All the other domestic Mark II plants have reinforced concrete containments. They're all flat bottom containments and they all utilize a T-quencher rather than a cross quencher.

(Slide)

It's because of these differences, principally because of these differences that we have some plant-unique load definitaions. I'll just summarize the difference between the load definitions that we utilize and -- or in other words, where we have utilized plant-unique load definitions as opposed to generic load definitions.

We comply with the NRC acceptance criteria in NUREG 0808 for all loca related hydrodynamic loads except that we developed an alternate plant-unique chugging load which is a conservative load definition not only for chugging but for condensation oscillation. Therefore we utilize it for both load cases and we've also developed a plant-unique SRV load definition.

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This slide summarizes some of the key elements of our plant unique SRV discharge load and chugging load definitions. The SRV discharge load is based on test data from in-plant tests conducted at the Caorso plant in Italy which I mentioned before. Caorso is a flat bottom reinforced concrete containment with cross quenchers. It is essentially identical to WNP-2 in terms of those parameters which govern SRV discharge loads in the pool. Those parameters include overall suppression pool geometry, SRV discharge line diameters and volumes, SRV blowdown conditions, quencher location, quencher submergence, and quencher geometry.

The Caorso in-plant test included single valve blowdowns under both initial and subsequent actuation conditions, and multiple valve blowdowns under initial actuation conditions.

An SRV discharge load definition was developed from the Caorso test data which is defined in terms of dynamic pressures on the suppression pool boundary.

The peak pressures and frequency spectra of the SRV discharge load conservatively bound the suppression pool boundary pressures which were actually measured in the Caorso in-plant test.

For application to No. 2, WNP-2, adjustments were made in the load definitions to account for differences in Caorso test conditions and WNP-2 plant conditions and design conditions. Using criteria which were developed in the Mark II program.

Confirmation of the adequacy of the SRV load definition was provided by means of evaluating in-plant test data from the Tokai plant in Japan. The Tokai plant is a free standing steel containment also, Mark II geometry.

It is a flat bottom containment and it utilizes cross quenchers. Therefore, the plant geometry and parameters which affect SRV discharge loads in the pool at Tokai are also essentially identical to WNP-2.

In Tokai, pressure amplitudes and wave form characteristics were similar to what was observed in Caorso and structural responses were similar to what is predicted for the No. 2 project.

The SRV load definition for WNP-2 was reviewed and accepted by the NRC with an increase in the magnitude of the peak pressure for added conservatism in the load definition.

In June of 1979 -- getting down to the chugging load now. In June of 1979 the Supply System submitted a proposed chugging load definition to the NRC which was based test data from the 4T tests. This design mode consisted of pressure impulse supplied at the discharge end of the downcomer in a finite element model of the suppression pool. Subsequently, additional steam condensation tests were performed in a modified configuration of the 4T test facility. This modified configuration or these additional tests are referred to as the 4T CO tests.

In the 4T CO tests some chugs were observed which imposed substantial higher pressures on the 4T CO tank boundary. And different frequency content than what had been observed previously in the 4T tests.

From this test data then that was generated in the 4T CO tests, Mark II owners group developed a generic load definition which involves solving a wave equation in cylindrical geometry. This approach may be utilized in a flat bottom but really is not applicable to the WNP-2 plant which has an inclined bottom or a bottom with a trapezoidal shape.

Consequently, it was necessary to modify the chugging load definition which we developed in 1979 and submit it to the NRC to reflect the new information about chugging.

Using an approach similar to what was used in the 1979 load definition, it was found that the magnitude and frequency spectra of the applied pressure on the 4T CO tank boundary could be simulated by an impulsive source applied at the discharge end of the downcomer in a finite element model of the 4T CO system.

Furthermore, the peaks in the frequency spectra of the pressures measured on the 4T CO tank boundary were found to be attributable to structural response of the 4T CO tank and acoustic properties of the steam in the downcomers and the water in the pool. It was concluded from this study that since the measured pressures on the 4T CO tank boundary were caused not only by the chugging in the ends of the downcomer but also by structural response of the 4T CO steel shell that in order to properly extract a source load definition for application to a steel containment that the effects of the structural response of the 4T CO shell had to be separated from the forcing function.

Therefore, a set of sources for pool disturbance were extracted from the 4T CO test data which are free of the physical characteristics of the 4T CO test facility. These sources produce dynamic pressures on the tank boundary 4T CO tank which bound the measured 4T CO test pressures and which also simulate the frequency content which was measured in those tests.

With this load definition, each source is defined in terms of a pressure gradient impulse applied at the discharge end of the downcomer in a finite element model of the 4T CO system. The load definition utilizes as parameters acoustic properties and damping properties for the steam in the vents and for water in the pool. This information was obtained from the 4T CO test data.

For application to a Mark II containment, the chug start times between vents with respect -- from one vent with respect to another are desynchronized in a manner similar to what was utilized in the generic Mark II methodology. And this accounts for randomness in timing which is known to exist because of observations made in the Jaeri test facility. In WNP-2 the desynchronization methodology is more conservative than the generic Mark II methodology which leads to added conservatism in the WNP-2 load definition.

As a result of the NRC review of this load definition, the WNP-2 chugging load was applied in finite element model of the Jaeri test facility, and was shown to bound the Jaeri test data.

In addition, this chugging load was shown to bound the effects of condensation oscillation and we therefore use it in all required load combinations which include either chugging or CO. Again, this plant-unique chugging load has been accepted by the NRC for both chugging and CO and it's not an open item.

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The only open item that we currently have in the containment systems area and it's not really a containment hydrodynamic loading issue, but a containment system issue as it relates to vacuum breaker impact loads. During either pool swell when you get wet well airspace compression as result of pool swell or during chugging when you get rapid fluctuation of pressures inside the vent, the vacuum breaker will open and it could open with impact velocities high enough on either opening or on closing to possibly damage the disc. Therefore, if that occurs that could lead to suppression pool bypass leakage, and therefore, this is a concern which must be resolved.

You're probably familiar with what is being done on the other Mark II plants to resolve this issue. This is also a generic issue. The other plants with Anderson Greenwood valves are doing something slightly different than what we're doing. Basically, the reason for that is that we have some slight differences between our valve design and the valve design on the other plants. These differences relate to the fact that in our plant we have a single valve body with two discs that -- if you can imagine this vacuum breaker is mounted on the downcomer through a flange, volted flange right here. This is the downcomer.

(Slide)

The front disc pivots around a shaft at the top. The rear disc pivots around a shaft at the bottom. The disc is held shut against the seat of the valve by means of torsional springs which are attached around the bottom between the shaft and the disc. In our plant, the disc is held shut therefore by a combination of that torsional spring and also with magnets which are embedded in the periphery of the disc.

Our solution to the vacuum breaker impact problem is to install shock absorbers or dampers, if you will, on the valve body which will attach to the shaft or to, in this case, rear disc to the -- there's another shaft up here to which a pivot arm is attached, which will dampen the impact load, reduce the impact velocity so that we do not get into a situation where we damage the vacuum breaker disc.

And that concludes my presentation on hydrodynamic loads except just in summary -- if we could go back to the first slide for just a minute --

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As I mentioned, this is an issue that's been around -- pressure suppression type containment designs for a long time now. A lot of actions have been taken in the intervening period to resolve the issue and as of today, the issue or the hydrodynamic loads are accomodated.

MR. PLESSET: Let's see if there are any questions on this point. Jesse?

MR. EBERSOLE: I might just have two questions. Are you going to do some SRV testing?

MR. FREDENBURG: We're going to do an SRV in-plant test to measure local cool temperature differences.

MR. EBERSOLE: Are you going to test in the regime where you get the nasty chugging problems and do some measurements on the vibration of the SRV downcomers?

MR. FREDENBURG: Well, the test for -- no, we're not going to do any additional test other than what's been done in the 4T test, the 4T CO test.

MR. EBERSOLE: You're not going to do any unique plant test for your --

MR. FREDENBURG: Are you referring to SRV in-plant tests for loads?

MR. EBERSOLE: Yes, SRV in-plant tests for loads.

MR. FREDENBURG: No, we do not plan to do any SRV in-plant tests to measure loads in the pool because of the fact that we have prototypical tests, those being the Caorso tests and the Tokai tests which really represent our plant.

MR. EBERSOLE: Well, you will put somebody down there just to listen to the rumbles?

MR. FREDENBURG: We'll probably have somebody standing outside containment and listening.

MR. EBERSOLE: I hope. Maybe with a tape recorder.

MR. PLESSET: You had another question.

MR. EBERSOLE: Yes, sir. At the last dynamics meeting, we were talking about bypass, in the event we lose one of these lines or lose a valve, and it's a matter of the degree of the bypass, and what was invoked was a thesis that the spray above the suppression pool would be a mitigating method in the event that you got a bypass. Subsequent to that meeting, it occurred to me that, and you can correct me if I'm on the wrong track, I don't know that the spray will do anything other than perform a condensation function up to a point where you get a laminer layer of uncirculated hot water on top of the suppression pool. And your heat transport mechanism is blocked by the fact that you don't have mixing. At least, that occurred to me after the meeting. So at this point I am inclined to deny that the spray system will accomodate as much bypass as was thought at that meet- And I would like to hear your opinion and maybe have you look at that unless you're convinced we won't have that kind of bypass.

MR. PLESSET: Let me help you help Mr. Ebersole. For instance, he's concerned about an SRV line breaking -- being broken above the water level, steam is discharging into the airspace, and he's concerned about what this might do. And if you have any comments on this. The answer I think he just told you was given, I think, by the staff, wasn't it, Jesse?

MR. EBERSOLE: Yes, I think it was some months ago.

MR. PLESSET: Suppose he had -- that the wet well sprays would help in the condensation of that steam that was being discharged into the airspace above the water line.

MR. EBERSOLE: But the problem is, see, I still have a heat transport problem after I lay this hot water, this condensed hot water down on the plastic surface of the pool.

MR. FREDENBURG. Okay. Well, let me try to address them one at a time. The first one we've evaluated, we've done Class I type fatigue analysis on downcomers and SRV discharge lines and verified that we don't exceed the criteria for a Class I fatigue analysis.

MR. EBERSOLE: On that score, may I make a comment? The question is really, what's the level of reliability in that analysis because of the critical nature of the consequence that we might have.

MR. ELTAWILA: Mr. Ebersole, I think the staff when he said the spray system is going to help. My name is Farouk Eltawila from the containment system branch. It's the dry well spray, not the wet well spray. Because when you have the steam line, the airspace region, you pressurize the airspace region higher than the dry well. The vacuum breaker will open and connect the dry well with the wet well. So if you enshade the dry well spray, it will help. The wet well spray definitely is not going to help, but the dry well spray is very effective in condensing the steam.

MR. EBERSOLE: So if you carry steam up through the vacuum breakers, then hit it with the dry well spray, it will condense and run into the lower region of the suppression pool? And then be taken off by the RHR pumps?

MR. CATTON: It'll drain right through the top of the downcomers.

MR. FREDENBURG: But I don't think in our case --

MR. EBERSOLE: So it will get circulated via that

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route.

MR. ELTAWILA: That's correct.

MR. EBERSOLE: All right. Fine. That didn't occur to me, so thank you.

MR. FREDENBURG: Just one more point on that subject. In ours, we've got a twelve-foot submergence on downcomers so that when the heated water does go down through the downcomers, it will enter the pool at a depth of twelve feet, and we really wouldn't expect to get pool temperature stratification.

MR. EBERSOLE: Well, will it enter the downcomers at a rate consistent with the mass flow needed to cool the -- through the heat exchange? Or will it simply sit there as a hot column? You know, having entered the downcomers.

MR. CATTON: It'll sit in the downcomers, Jesse.

MR. EBERSOLE: It won't move.

MR. CATTON: It won't go out of the -- it will slowly displace the cold water.

MR. EBERSOLE: I guess I'm still stuck on the thesis that I don't know what the circulatory pattern is, and whether it's consistent with the mass flow needed to move the heat off to the heat exchange. Do you follow me? I don't get homogeneous mixing. I get a laminated structure, and I may not be able to reject the heat. I'll just get a layer of hot water, either in the downcomers or on top of the wet well on the outside of the downcomers.

MR. FREDENBURG: I understand your question and I think this is also an issue which we are in the process of preparing a response to with regards to the issues raised by Mr. John Humphrey. We've -- I believe it's the same issue regarding pool temperature stratification.

MR. PLESSET: Oh, he had a general question about pool stratification.

MR. EBERSOLE: I don't recall that. It was very general. It wasn't this specific.

Well, I guess we'll have to get some sort of confidence that we've got heat transport.

MR. PLESSET: Yes, Jerry?

Ivan? Walt? I guess nobody wants to make any more trouble.

MR. CATTON: I think they've done a good job on the submergence pool.

MR. FREDENBURG: Okay, our next speaker is --

MR. NELSON: No, he's not. You're the last speaker.

MR. PLESSET: We do not have security discussions at subcommittee meetings because we do not have provisions for closed sessions. However, we most likely will have one at the full committee meeting. So do you have any final comments that you would like to make on your side?

MR. BIBB: No.

MR. PLESSET: Al, do you want to make any concluding remarks?

MR. SCHWENSER: No.

MR. PLESSET: Just a moment, Al.

MR. EVANS: I just want to make one correction for the record for Mr. Ebersole's question on the cooling. It was the standby service water, not the RHR that provided emergency cooling water. I just wanted to correct that for the record.

MR. EBERSOLE: Now, wait a minute. What water was this?

MR. EVANS: This was the emergency cooling units for the MCC and switchgear rooms that we were talking about.

MR. EBERSOLE: Oh, okay. Thank you.

MR. NELSON: The reference was made it came from RHR. It didn't.

Dr. Plesset, the Supply System would like to make one closing remark related to expressing our thanks to the Committee for allowing us to give our presentations in almost complete fullness. And I hope that we have answered the questions that the Committee may have had, and I hope we didn't leave too much outstanding, but we certainly want to express our thanks for you blessing us with your visit to the glorious Tri-Cities.

MR. PLESSET: Well, thank you, I'll come back to you after we hear from Al, if you'll wait a moment.

MR. SCHWENCER: We just checked. We have no further comments to make.

MR. PLESSET: All right. Thank you, Al. Presumably your unresolved issue list may even be reduced further.

MR. AULUCK: Yes, in the next two or three weeks we hope to resolve at least three or four more issues.

MR. PLESSET: All right. Well, let me tell you that I expect that you'll be coming in October 7th or 8th, I can't tell you which day because the agenda hasn't been finalized as of yet, but you will be coming in. I don't know if you're happy about that, but I think you should.

MR. NELSON: We are.

MR. PLESSET: But you'll only have four hours. I mentioned that before. And so you have a large problem. You have to be prepared to answer questions on anything, but to make short presentations. And have time for questions from Committee members. And that's going to be one of your chores between now and then, to decide how to do this, because what you told us was very interesting, very pertinent, and I think, very helpful. And I think I speak for the Committee and our consultants when I say we appreciate your effort. We appreciate the tour. It was very well organized, and the presentations here were also well organized. A little voluminous for a full committee meeting, but that's the way it is when you go to the full committee. And I thought you did very well indeed, and I hope that you will uphold my prediction that you'll do well at the full committee.

And with that thought, I'll adjourn the meeting. Thank you all.

(Whereupon, at 3:12 p.m., the meeting in the above-entitled matter was adjourned.)

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

in the matter of: Subcommittee on Washington Public Power Supply

Date of Proceeding: September 3, 1982

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Place of Proceeding: Richland, Washington

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

Margaret Miller

Official Reporter (Typed)

Margaret Miller

Official Reporter (Signature)