ORIGINAL ACRST-1504

UNITED STATES
NUCLEAR REGULATORY COMMISSION

50-267

IN THE MATTER OF:

DOCKET NO:

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON FORT ST. VRAIN

LOCATION: PLATTEVILLE, COLORADO **PAGES:** 1 - 249

DATE: WEDNESDAY, APRIL 2, 1986

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PUBLIC NOTICE BY THE

UNITED STATES NUCLEAR REGULATORY COMMISSIONERS'

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

WEDNESDAY, APRIL 2, 1986

The contents of this stenographic transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards (ACRS), as reported herein, is an uncorrected record of the discussions recorded at the meeting held on the above date.

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON FORT ST. VRAIN

Visitors Center of
the Fort St. Vrain
Power Plant
16805 WCR 19½
Platteville, Colorado

Wednesday, April 2, 1986

The subcommittee meeting convened at 8:30 a.m., Dr. Chester P. Siess, chairmar, presiding.

ACRS MEMBERS PRESENT:

DR. CHESTER P. SIESS

MR. DAVID A. WARD

JOHN McKINLEY, ACRS Staff Member

P R O C E E D I N G S

MR. SIESS: The meeting will come to order. This is a meeting of the ACRS Subcommittee on Fort St. Vrain. I'm Chet Siess, chairman of the Subcommittee. We have one other Subcommittee member present today, Dave Ward, who is also chairman of the ACRS, seated on my right and John McKinley at the other end of the table is the assigned ACRS staff member for this project. The purpose of this meeting is to explore a number of technical issues that have developed since the last time we were here. That was May 17, 1984.

We expect to discuss the Public Service Company of Colorado's Performance Enhancement Program and the various regulatory issues. We will also expect to hear about the technical support and development available to PSC and Fort St. Vrain. The detailed agenda has been posted at the entrances to this meeting room. The meeting will extend through today and, weather permitting, will continue tomorrow and go until about noon.

A transcript of the meeting is being kept. I request that each speaker first identify himself or herself for the reporter and then speak with sufficient clarity and volume so that he or she can be heard and reported. We have received no written statements from members of the public regarding this meeting nor have we received any requests to make oral statements from members of the public. If anyone would like to make a statement relating to the topics of this meeting he may contact Mr. McKinley and we will try to arrange time for such a statement. Try to see him early today if you can. Dave, do you have any questions or documents regarding the agenda?

MR. WARD: I have none.

MR. SIESS: Then we'll proceed to the second item of the agenda and begin with Mr. Walker of the Public Service Company of Colorado.

MR. WALKER: Thank you. I want to welcome you all. One of the nice things about meetings like this is you get to see old friends that have been around about as long as I have in this business. I want to welcome you here. It has been since May of 1984 since a Subcommittee visited the plant. A lot of things happened since that time. I was not at that particular meeting. As I was driving up this morning I thought back and I guess it is a sign you're getting old if you reminisce a little bit, but I'm going to do it anyway for a couple of minutes. I was remembering back to 1968 when he got our construction permit and I had an opportunity to appear -- I think you were there, Don, and Dr. Siess was there -- the Advisory Committee on Reactor Safeguards and thinking back to some of the things, we gave a lot of attention and a lot of discussion to is kind of interesting. One big thing of course was secondary containment for the

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plant. There was some divided opinion on that.

As you all know, that came out, we ended up with confinement instead of containment. One other thing was the fuel particles, a question of whether to have the biso or triso particles, and whether they had silicon carbide there to make the carbide perform. The other thing that came to mind, one of the last things, was some concern about the tritium release, and we agreed with the titanium sponges. As I look back, the secondary containment, the fuel particles or the titanium sponges or the tritium problem really have not been problems. There was also some concern back in those days about some of the equipment, a lot of work done on the steam generators, helium circulators. We did extensive testing on the main circulator at our Belmont plant.

In retrospect, and we all can look back, we should have spent more time testing the auxiliaries to the helium circulators rather than the circulators themselves, but it is nice to look back and see which things have worked out and see the challenge that faced us in some of the other technical problems. We have a very full agenda. We want to cover all the things Dr. Siess has indicated in his opening remarks, and I hope everyone has a copy of the book which has the present technical presentations spelled out in that, and so I think probably we should get along with it. We'll try to keep on schedule as best we can. I would like to call on

Ken Heitner now with NRC, who has a few remarks.

MR. HEITNER: I'm Ken Heitner. I'm the NRC employee in the Office of Nuclear Reactor Regulation who is responsible for Fort St. Vrain as the project manager. The Subcommittee asked me to talk to a couple of topics today. The first was a question of how the retransfer of Fort St. Vrain back to the Office of Nuclear Reactor Regulation has affected the handling of licensing for this plant. As you recall, Fort St. Vrain was licensing was transferred to Region 4 in December of 1982, and then more recently you were brought back to the Office of Nuclear Reactor Regulation beginning in October of 1985.

During this approximately three-year period, the plant was nominally having all of its licensing actions handled through Region 4 and during this period of time under the regionalization program, all of the plant-specific reviews, the licensing issues that were unique to Fort St. Vrain, were the responsibility of Region 4. The Office of Nuclear Reactor Regulation in Washington retained an oversight role and also the responsibility for performing the reviews on all the generic issues, those which not only affected Fort St. Vrain but a number of other reactors.

There was, during this period of time, one person still in the Office of Nuclear Reactor Regulation known as the oversight project manager who had responsibility for coordinating all of that generic licensing activity, and I think that basically what happened, although initially Region 4 was handling all of the licensing actions that were specific to Fort St. Vrain, gradually over that three-year period, because there were so many problems having to do with Fort St. Vrain, the Office of Nuclear Reactor Regulation in Washington became more involved at Region 4's request.

MR. WARD: What is the involvement, ongoing involvement in number of engineers, let's say?

MR. HEITNER: I will get to where we are right now as I proceed here.

As we move back to after October of last year, all of the licensing actions were transferred back to NRR by mutual agreement with NRR and Region 4, certain licensing responsibilities for doing technical work on certain licensing actions was retained by Region 4. NRR also delegates, again by mutual agreement, certain licensing actions to the regional office for the performance and technical work involved. The specific assignments retained by Region 4 that are of some importance are the review of Fort St. Vrain's Appendix R safe shutdown model which is continuing, and the LCO 4.1.9 which concerns the flow requirements for the reactor at low power between zero and now, in the new proposal, about 25 percent power operation.

During the transition of the plant back to NRR, I

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think there have been a minimal number of problems, communications between Public Service Company, Region 4 and NRR remain effective. Our current level of effort in the Office of Nuclear Reactor Regulation is to have two project managers for Fort St. Vrain, myself and Charles Hinson who is here today. This is a decision made soon after the retransfer or in fact actually before retransfer, that we would retain that level of manpower for project management purposes, simply because of the large number of unresolved problems concerning Fort St. Vrain and the fact that it was a unique plant.

MR. SIESS: Is Fort St. Vrain your sole assignment?

MR. HEITNER: Yes, sir.

MR. SIESS: Both of you?

MR. HEITNER: Yes.

In addition, the office director has made available to us increased technical assistance resources. We're approximately going to spend in the order of half a million dollars this year for technical assistance resources. We have support contracts with three national laboratories, Oak Ridge National Lab, Los Alamos National Lab and Idaho Lab.

MR. SIESS: Would you tell us briefly what those three labs are doing?

MR. HEITNER: Oak Ridge has helped us primarily in calculations having to do with the operation of the reactor, called reactor systems calculations, because they possess the ERECA code, which is a very accurate model for Fort St. Vrain's behavior. LANL has been helping us with questions having to do with fuel block cracking, with questions having to do with moisture ingress into the reactor. LANL also played an important role in our resolution of problems having to do with the control rod drive mechanisms and the PCRV tendons. Idaho National Engineering Laboratory -- I should point out Oak Ridge is also helping us with tech spec upgrade program. Idaho National Engineering Laboratory is currently helping us with technical specification upgrade program. They are helping us with some problems having to do with the fact that the emergency diesel generator systems may not meet the single failure criteria: the control systems for those diesels are interreacting. And they are also helping us review Fort St. Vrain's proposal for a long-term fuel surveillance program which will eventually be placed in the specifications.

MR. WARD: With this transition from first in '82 and back to NRR in '85, and I assume that I don't know how long running these are, but how would you characterize the continuity and the experience in the reactors of the people involved in that? That's a question that's been raised and I would like to hear what you have to say about it.

MR. HEITNER: I think when we met with the Commission last fall to discuss the fact that Fort St. Vrain needed an extension of its time to meet the deadlines for the equipment qualification program, at that time, Mr. Denton stated that he felt that we had not put into Fort St. Vrain the necessary resources to handle all the licensing issues that were before us as quickly and as expediently as some of those issues deserved to be resolved. I think now the fact that we have two full-time project managers, the fact that we have essentially all of the technical assistance resources that we need, we are dealing with the problems as rapidly as we can. We are still trying to build our level of expertise by adding additional people or consultants to our staff in order to help us with these types of problems.

MR. WARD: You're adding consultants?

MR. HEITNER: Yes. The person who is here today is Dr. Peter Fortesque who is a well-known consultant and expert in his field. He's recently been put under contract to NRR to help us.

MR. WARD: What about the three national labs, the support you get? Is there any experience with gas reactors going back five or 10 years?

MR. HEITNER: Los Alamos has been under contract to NRR for at least five or six years now, helping with some of these problem areas. People at Oak Ridge National Laboratory were helping us Sid J. Ball, the primary contact there has extensive, eight or 10 years, experience and I think his work is well-recognized.

MR. SIESS: What's your background?

MR. HEITNER: I have been involved with the Fort St. Vrain project for about a year and four months now.

The licensing for Fort St. Vrain is being handled under new NRR organization in the division of BWR licensing-B and it is in the standardization of special project director. The two major problem areas that we are working with Fort St. Vrain and Public Service Company of Colorado to resolve I would like to briefly give you a status report on those as I discussed earlier. The first one has to do with Appendix R, fire protection. We're still reviewing -- well the plant is currently operating under interim compensatory measures which we've reviewed and approved. The basic nature of those measures is the plant is standing a roving fire watch that gives an added advantage of detecting and suppressing fire early.

We're continuing to review both the fire protection features and the safe shutdown model. Our review of the fire protection features is complete and we have a draft of our evaluation that would grant Fort St. Vrain the necessary exceptions that they need to be in compliance with

Appendix R except in those certain parts of the plant that have problems. We're still trying to resolve problems with safe shutdown model.

At the same time, while this review is going on, Public Service Company is putting in place the necessary modifications that they need to bring the balance of the plant into compliance with Appendix R with the exception of the specific areas where they have asked for compensations, and we feel they are supportable, but that has to be contingent on our acceptance of the safe shutdown model, so we're still working on that part of the review; we can't grant any exemptions.

MR. SIESS: Can you help me get a perspective on this? As I recall when Appendix R first came out, and Fort St. Vrain made a review, particularly on cable routing, and decided that there wasn't much they could do with that three-story, what do you call it --

MR. HEITNER: Control complex. Electrical complex.

MR. SIESS: At that time, they decided the only way they could solve that problem was what ended up being the ultimate cooling method, dedicated diesel and the line of cooling system with cables routed separately from all the other systems. I thought at that time that was accepted as a solution to the Appendix R requirements. Now that was several years ago. What has happened in the interim?

MR. HEITNER: Well, there's still the question of resolving whether that concerns itself with the fire that affects those areas in the three-room complex, and we've already essentially given them a special interpretation of the Appendix R for that particular area. However, there is still the question of what happens if the fire occurs in the balance of the plant, somewhere in the reactor building or in the turbine building, can they demonstrate that one fire occurring in one of those buildings will not damage enough equipment that they cannot bring the plant to safe shutdown? You realize if they lose the congested cable complex they will be put in a situation of permanent loss of force cooling and they essentially have to demonstrate that they wouldn't have any damage worse than design basis accident number 1.

However, for the balance of the plant they still have to have the capability of shutting the plant down with no damage. That's what we're trying to resolve.

MR. SIESS: Why is the NRC interested in shutting the plant down with no damage?

MR. HEITNER: That's what Appendix R says you have to be able to do.

MR. SIESS: I thought it said you have to be able to shut it down with no hazard to the public.

MR. HEITNER: I guess our interpretation for that is what would be for Fort St. Vrain a normal safe shutdown with forced circulation in cooling.

MR. SIESS: The question is not a fire that would damage now the alternate cooling method systems, but that would damage something else?

MR. HEITNER: Normal safe shutdown -- they have to be able to show -- the way we're approaching this is that they have sufficient redundancy in their safe shutdown equipment that if certain equipment is damaged by a fire in either the reactor or turbine, that there's enough redundant equipment in the plant that they can safely shut down. Safe shutdown is a normal forced circulation cooldown with no damage to the reactor.

MR. SIESS: Is that a new interpretation of Appendix R or was that in effect back at the time the alternate cooling method was put in? I know it has been going through stages --

MR. HEITNER: This interpretation for the balance of the plant is entirely consistent with what we're asking the light water reactors to be capable of doing, is my understanding. What we have done is for the specific problems of the congested cable areas and the three-room complex, we've created an additional exception for Fort St. Vrain, because there would be no other way of them dealing with that particular fire and the damage resulting from it.

MR. SIESS: So for example at Oconee, where they had to put in a separate decay heat removal system, that addressed design basis accidents, not severe accidents, right?

MR. HEITNER: I couldn't tell you about Oconee, but let me give you another example which I'm more familiar with. That's the case of Maine Yankee. There they were unable to demonstrate that the normal safe shutdown trains were separated, because of all the common cabling rooms and switch gear rooms. They came up with a system that used existing equipment that was separated from the normal safe shutdown trains and added some additional power supplies and control panels, also separated from the normal safe shutdown trains, so that they had an alternate method of shutting down that involved lashing things together with fire hoses and flooding steam generator.

MR. SIESS: Sounds more like the solution arrived at on some of the SEP plants, jury-rigged type things.

MR. HEITNER: Right. Fort St. Vrain has that option in demonstrating that for its normal shutdown equipment, but they still have to show that there is redundant equipment and that it is adequately separated so that it will not be damaged by the fire that damages the main train.

MR. SIESS: The time it takes to do that is --

MR. HEITNER: In fact, with Fort St. Vrain, you can take more time to do all the things that you are going to do.

MR. WARD: I'm not sure, how is the alternate, additional alternate shutdown system credited in the Appendix R implementation then?

MR. HEITNER: Are you asking me for Fort St. Vrain or --

MR. WARD: Yes. For Fort St. Vrain.

MR. HEITNER: First you have to demonstrate that you have the equipment. The second question that we still have to resolve is if you have additional equipment that you are going to take credit for above and beyond the equipment that you would normally have for your safe shutdown train, then I think what the licensee has to eventually do is propose sufficient technical specifications to demonstrate that that equipment is operable and available, perhaps not as severe as the requirements in the normal safe shutdown equipment, but that the other equipment is available, that it doesn't just languish in some corner while he's taking credit for it, but it is not operable. He has to propose -- he may have to propose additional technical specifications to show that that equipment is being surveilled at some interval and take compensatory measures if that equipment is not available.

MR. SIESS: Are you saying the ultimate fueling method won't shut the plant down; it will just keep the core from melting? Not melting in this case, that's not a good word --

MR. HEITNER: What I'm saying is that the alternate cooling method system, as I understand it, in the congested cable area, will resolve effectively the loss of all forced circulation cooling and put you into the design basis accident one scenario. You'll still have cooling and preserve the integrity of the PCRV but have an overheating of the core and release of all the fission products, as the core heats up, from the fuel particles into the coolant, because almost essentially all of the core will be over the 2900 degree F temperature after a power trip.

MR. SIESS: Loss of all circulation?

MR. HEITNER: Loss of all forced circulation.

So anyway, the status of our Appendix R review is that we're part of the way through it. We still have some problems to resolve. Public Service Company is also still in the process of completing certain modifications of the plant that will eventually bring them into complete compliance with Appendix R.

The second major problem area that we're still working on is compliance with 10CFR50.45, equipment qualification. The plant operation is currently continuing under an extension granted by the Commission last fall on the November 30, 1985 deadline for equipment qualification. That allows the plant to plate up to 35 percent full power through May 31 of this year. The Staff realizes that PSC has a lot of problems to resolve concerning equipment qualification, both because of the fact that it is an older plant, sometimes it is difficult to recover the data you need that might have been available at the time of construction, but has somehow disappeared over the years, or is not available to demonstrate that the equipment in the plant is qualified.

PSC also has to face up to the fact that Fort St. Vrain, because of it's high temperature steam conditions, had a unique problem qualifying it's equipment because a break from from a 1000 degree main or reheat steam line creates an environment that's more severe in terms of temperature than is experienced in any water reactor even in containment. PSC has elected to resolve this problem by approving the new steam line rupture detection and isolation system, which the staff is also reviewing. The purpose of this system is essentially to isolate very large breaks that would create a very harsh environment very rapidly within the plant automatically.

By utilizing this system, PSC is projecting that the environment in the plant for the equipment will be somewhat milder and more comparable to what we find in a water reactor and therefore they can avail themselves of a lot wider data base and experience that's been developed for equipment qualification for a lot of other plants. However, there are still problems that are unique to Fort St. Vrain and we have been meeting frequently practically every month now to discuss these problems, both to resolve the problems normally handled by the NRR under this licensing action and also to anticipate problems that would come at the time that the plant would be inspected by the Office of Inspection and Enforcement. I can only say that a great deal of effort will be required by both the NRC Staff and by PSC in order to bring Fort St. Vrain into compliance with this regulation.

MR. SIESS: Again, can you give us a little history on this? I have the impression from following this that at some time in the past, there had been equipment qualification reviews of Fort St. Vrain and the Staff had signed off on it and then it came up again. Can you correct me if I'm wrong or give me a little background on that? When was it discovered that that 1000 degree steam presented a special problem?

MR. HEITNER: Let me try to give you my perspective of being involved in this both as the NRR oversight project manager from approximately November 1984 through end of August of last year and being project manager at NRR since then, and couple that with what reading I have been able to do about this problem. It is clear to me that I think part of the problem has been that we have just not communicated effectively as to what qualification really meant. PSC had proceeded to implement earlier initiatives from the NRC and felt that they were qualifying the equipment adequately.

There was a considerable effort to qualify equipment shortly after the plant was licensed in 1973 and 1974. In fact, I think it was a separate supplemental safety evaluation written then. PSC has documented very carefully the fact that they have tried to respond to every NRC initiative in this. Perhaps what we had done in 1983 and 1984 was not respond as rapidly to identify back to PSC areas where we felt they were going down the wrong track, where they were taking approaches that we didn't feel were consistent with the way we were qualifying or accepting qualification of equipment for other plants, and it was only early in 1985 that two or three major issues evolved that separated us.

The first one had to do with the fact that PSC had initially depended on isolating any sort of steam line break through operator reaction. In other words, there was no automatic isolation of breaks. It depended on the operators either sensing the break directly by the fact that they hear it in the plant or be aware of it through the instrumentation, and then they had to take manual action. Well, the NRC over the last -- and that had been the position that PSC had taken ever since the plant was licensed in 1973.

I guess over the decade from 1973 to 1985, the NRC had become -- Staff had become a lot more conservative about accepting the fact that an operator can take any manual action even in the control room to prevent or control or mitigate an accident, and the whole basis of their qualification program had been on the fact that the operator had to take action within four minutes. If they waited 10 or 12 minutes, which the Staff might feel was a more defensible time scale, for the operator to take action, based on their review of how quickly operators can respond to accidents and emergency situations, the 1000 degree steam temperatures created temperatures in the plant that were far too harsh for the equipment to survive, so that was the first fundamental problem.

MR. SIESS: Is that a fact or an assumption? The 1000 degrees is too harsh.

MR. HEITNER: PSC developed curves that showed that the temperatures were too high, so that's the first problem.

MR. WARD: I didn't understand the phenomena well enough. Is there a threshold or is it sort of a continuum?

MR. HEITNER: Hot steam pours into the plant and the temperature goes up. All those curves have been developed. I think those are actually developed in '73 as a basis for the qualification work that they did at that time.

That was the first major problem area. PSC responded to that now by going ahead and proposing the automatic isolation system. The second question --

MR. WARD: But you feel you are involved in that early enough now so that if they are going down what you are going to conclude is a wrong road you are letting them know?

MR. HEITNER: Yes, I hope so.

The second problem area, and this is the one where I have a little difficulty explaining myself clearly, has to do with the details of how the equipment is considered to age, called thermal aging process, how the equipment ages both in its normal operation in the plant and also the accumulated damage from the accident scenario where the equipment temperature is elevated; and we had differences in methodology that had to do with how those determinations were made.

In addition, in August of 1985, as PSC was proceeding to resolve these identified problems with the equipment program, they discovered additional problem areas in the plant that they have since sought to resolve on their own, problems having to do with splices that were clearly not qualified, splices in cabling, certain problems with potential submergence of equipment; but I think all these problems they have resolved on their own. There are still problems that we're trying to work.

As I said, one of the problems they have right now is some of the older cabling in the plant they cannot positively identify, so they cannot possibly go to a qualification test report for an existing cable or type of cable and say it was qualified because it was qualified by this particular manufacturer in this particular test report. Other plants are having the same problem right now at Sequoyah, I understand, so we're trying to work with them to resolve the problems.

MR. SIESS: Let's me try to summarize my understanding. It seems to me there are two kinds of problems on equipment qualification. One is the same problem that other older plants have had. The equipment was bought years ago and installed years ago before people were looking at qualification. Some of it is equipment that is not used now, hasn't been qualified recently for some new plant, so it is just establishing a qualification base by comparison, without taking it out and testing it. That's a fairly common problem for older plants and even for some newer ones.

The other problem is more nearly unique to Fort St. Vrain and it is the high temperature steam. That was recognized by PSC when they got into the qualification, but they thought they could control that temperature rise by the operator action, and that's where there was a disagreement with NRC.

MR. HEITNER: We effectively accepted their position on operator action initially. Or never contested it. It was on the docket for a decade.

MR. SIESS: That issue has been raised, how much time is involved in some other system --

MR. HEITNER: PSC has now made the decision to put that issue to bed by proposing --

MR. SIESS: The high temperature steam was recognized initially by PSC. It is just that their solution in time became unacceptable to changing NRC requirements. I wouldn't want to use the term ratcheting -- okay, I think I understand now.

MR. HEITNER: Okay.

MR. WARD: Does seismic qualification fall under 50.49?

MR. HEITNER: I don't think that's a problem.

MR. WARD: It is not a problem or doesn't fall under 50.49?

MR. HEITNER: My understanding is that it won't come under that. It is only environmental qualification, but that's -- I'm not sure. It is not an issue in terms of any of the pieces of equipment that we're working on.

MR. SIESS: That concludes it?

MR. HEITNER: That's all I would say now.

MR. SIESS: Thank you very much. You have been helpful. The next item on the agenda calls for representatives from Region 4.

MR. JAUDON: I'm John Jaudon with project responsibility for the inspection program at the Fort St. Vrain site. With me today is Dick Ireland who formally had project responsibility for Fort St. Vrain and is currently in charge of our engineering section and Bob Farrell our senior resident inspector at the site. Today I shall provide information on the performance of Fort St. Vrain. The last SALP period -- or systematic assessment of licensing performance for the rest of the audience -- ended on February 28, 1985. The current period ends at the end of this month, and since the deliberative process of SALP has not been completed, the comments I make in each functional area are essentially opinions based on talks with inspectors and reading the reports. I want to make sure you don't understand them as a preview of what the SALP board will say.

MR. SIESS: You mean your opinion?

MR. JAUDON: Yes, the SALP board has not met yet.

MR. SIESS: But that's also an opinion?

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MR. JAUDON: That's correct.

MR. JAUDON: The present SALP period will end at the end of this month.

MR. WARD: So that's a 14-month --

MR. JAUDON: 14 months. The last SALP found Fort St. Vrain to be in category 3 in plant operations. We have given the operations area extra inspection effort, especially prior to the plant start-up last summer. SALP recommended there be an increase in vigorous management attention. We see a lot of evidence of this. The plant is operated, albeit at low power. During this we believe that operator morale and performance have improved.

MR. WARD: How do you judge that? Can you give me an example of how you come to that conclusion?

MR. JAUDON: I think you can sample it by watching the people operating professionally in the control room. You watch how close they get to making mistakes. You watch how many mistakes they make. It is subjective.

MR. WARD: That's performance. You said morale also. How do you judge the morale?

MR. JAUDON: I would defer to what my senior resident says, but he comes in on mid-watches and at odd hours when nobody is around and the operators are human beings and they talk to him, tell him what they are thinking or what they want him to think they are thinking. He sees the flavor of what they are telling him. It is very subjective.

MR. WARD: I understand. I'm trying to get an appreciation for it.

MR. JAUDON: I think we see in my visits up here, if I get up here once or twice a quarter, I go in the control room, I talk to operators, I see them in a different flavor. I don't hear so many complaints about they are picking on us all the time.

MR. WARD: Who is?

MR. JAUDON: The NRC. Maybe they just accept it, I don't know, but we don't see near as much of that. We hear positive talk.

MR. WARD: That's a sign of better morale; they conclude that the NRC is not picking on them?

MR. JAUDON: They talk about how they will make it run. They don't talk about how it is somebody else's fault that it doesn't run.

MR. SIESS: The Stoller report commented on morale. What's the timing of that report as compared to your most recent?

MR. JAUDON: My most recent observation was yesterday afternoon when I came in the control room.

MR. SIESS: The Stoller report was dated what?

MR. NIEHOFF: If it was the Stoller report, it was the end of 1985.

MR. SIESS: I'm just trying to relate the two.

MR. JAUDON: We think the development of the technical specifications may help in the plant operations, because they don't have tech specs that are easy to use right now. Maybe I get too used to standard tech specs. It is a lot easier to use tech specs. You can find things in a hurry. In the area of radiological controls the licensee was in category 1. This remains a comparatively strong area.

A lot of it may have to do with the fact the plant design minimizes their occupational radiation exposures. They basically take a very carefully and conservative attitude toward problems in the radiological area. We haven't had any problems in that area. The maintenance area was rated 3 by the last SALP. Senior resident inspector and I think we may have seen some signs of improvement in this area, we started an in-depth assessment in this area with the Region 4 team -- that's basically three contractors from Idaho and one of our inspectors -- last Monday. We are doing these at all the operating sites and this is the third site we've come to. We're starting to get a better feel of where they stand in maintenance when we finish, the area of surveillance; they were category 2 at the time. They really haven't had anything extraordinary happen in surveillances. They missed a couple of surveillances or almost missed a couple they shouldn't have. We don't see any big change in that area. Nothing spectacular, nothing real bad happening. A significant improvement could result from these new tech specs. They make it easier to understand.

Fire protection, that's implementation of it, was also category 2. The principal activity recommended was a continuing recommendation of Appendix R items. You've already heard a discussion on that. The Appendix R inspection is tentatively scheduled for later this year, based on resolving these items. That's the acceptance inspection. Certainly in the last year or so the housekeeping has improved dramatically in this plant. The emergency preparedness area in the last SALP fell from category 1 to 2. The 1985 emergency drill identified quite a few problems. Whether one in this area received as much management attention as was recommended by the last SALP is a question for the next SALP board.

MR. SIESS: Problems on site or off site?

MR. JAUDON: I think a lot were off site, as observed. It does not appear to be one of the licensee's strong areas. In talking to inspectors, they are not convinced the licensee is convinced they can have a big accident. That maybe he doesn't put as much effort in that area.

Security was in category 2 in the last SALP.

Since then there have been several problems brought to light. These problems are the subject of potential escalating enforcement actions that are still under staff evaluation. We're still working on those.

I don't want to discuss the details of security problems in this forum, but I can say that the people in that area think that the licensee now understands what problems are in the area of security and the corrective actions they have started. They think they have hit bottom and have started back up. They have indications of that.

Outage is a new SALP category but encompasses the old areas of reviewing and function design changes. Recent inspections have revealed the continuing improvement in housekeeping which also figures in outage, but we found some minor problems in design changes, the control of the design changes, the completing of them in the sense you get all the drawings and paperwork up to date, which is kind of like a cancer growing if you don't do that right. It comes back and gets you later on. So we think they need more attention in this area.

Training was previously a category 2. They have been heavily involved in the influoridation process. I don't see any real big changes in that area. They suffer, of course, from the fact that this is a unique plant. There is no simulator for it. In their training room the simulator happens to be a set of pictures pasted on the wall that are lifesizes of the plant.

Quality assurance administrative area was also rated a 2. In this area, the SALP board recommended inspection effort be increased; they also recommended increased management attention in this area to emphasize the QA deputies' independence and capability to provide timely corrective action.

MR. SIESS: Why would they recommended increased inspection effort for category 2? I thought category 2 meant the same?

MR. JAUDON: But when you add everything up, further weakened or the same or you see a declining performance, they say we need to probe more on this area. We might find them one in the category but for the first year we'll not back off the inspection because we don't update it really. If somebody ended p a 3 you might already have seen the category changed and they might be on the upswing and you might not want to put a lot of resources in it. The snapshots are such big time frame simulations.

We have had from the licensee quarterly updates on the status of the performance enhancement program he's going to talk about. It is the implementation of the contractor recommendations for management improvement. Licensee has recently taken over the directions program from the contractor that was helping him manage it, and I guess he'll talk about that. It is really a little premature to talk about this, you know, overall assessment. This is really a management effectiveness assessment before the SALP board meets. If we see some -- but I don't think we see evidence that they are head and shoulders above the crowd out there. By that I mean we don't think that they are at the bottom anymore either.

We see the licensee trying to do bootstrap improvements all over the place simultaneously, and this is difficult to do. It takes a tremendous effort to pick up a whole bunch of areas simultaneously. If you add them up we see an all-out positive trend with maybe a couple of downs in there.

I've got a couple of final thoughts which -- we all know this plant is very unique. We have recently arranged for something we have not had for years which is some special training, albeit it is only 48 hours' word, but we're sending a bunch of folks from the Region and I think NRR is sending people too and try to increase the Staff's basic understanding of high temperature gas reactors in the world, for those of us that suddenly inherit a big plant like this with not a long background in gas reactors. That takes place later this month in San Diego. We think that's a positive step.

MR. WARD: How many people from the Staff will attend that?

MR. JAUDON: About 20. Branch chief, myself, Mr. Ireland is going, Mr. Farrell is going.

I have a second thing that bothers me as kind of the new kid on the block. I think there's a basic defect in what we do with it in our regulation of it. That's because they have so many systems which can help to mitigate an accident or a cooler reactor, and many are treated as kind of semi-safety-related; and for every other plant we regulate, we have a nice -- you got a lot of systems too a nice, hard list and we say this is the ESF and we based it all on this nice, clean little list. There is no nice, clean list at this plant. Depends on what we talk about with them, what areas. I think it has muddled the regulation of this plant for a long time. Maybe the new tech specs will clean that up.

MR. SIESS: I don't think that's unique for a gas plant. I went through most of the SEP plants, old plants. Some didn't even have an ECCS like we consider it now. Big Rock Point has a fire pump. They found lots of systems that could be used to shut the plant down safely. As we look at severe accidents, which is really what we're concerned about, we're finding lots of systems that are not -- I don't remember whether it is safety-related or important to safety. Well, they are not safety-related in the sense of the regulations. They can be used. We're finding this all over.

MR. JAUDON: I agree with you --

MR. SIESS: This isolation of a selected group of systems, that these are the only ones included in the FSAR analysis therefore they are the only ones we have to look at, I think that's wrong. There are other systems that will do the job, are probably built just as well as the ones you got at the FSAR, they just didn't have the documentation; and I don't think that it is unique to Fort St. Vrain.

MR. WARD: I think what you are saying -- and I agree -- it is not unique and it is not necessarily bad.

MR. JAUDON: But where do you apply the regulations? That's a gray area.

MR. SIESS: This is a safety-related/important to safety issue. The same old thing. And it is the thinking that something that's safety-related is 10 times as reliable, 10 times as good as something that wasn't; and it is probably the same pump and same valve, it is just not inspected as often and there's not the paper that goes along with it.

MR. JAUDON: I don't argue with any of that.

MR. SIESS: It is a regulatory problem.

MR. JAUDON: It really is.

MR. SIESS: Of what you define and what you inspect and what you look at. These plants are much more versatile than that safety island or whatever it is that the FSAR is based on.

MR. JAUDON: In a light water reactor they are generally similar plants, and some issues surface at each one, and maybe they get resolved. Here it is always unique.

MR. SIESS: You look at the older plants and you'll find situations just like these. We looked at Big Rock and Yankee Rowe and they don't look anything like what we're looking at now.

MR. WARD: I guess I would like to see a plant designed to optimize safety, not to optimize the ease of regulation, and I agree there's some overlap there, but --

MR. JAUDON: Oh, yes.

MR. SIESS: We hope there is.

MR. JAUDON: It gets to be not ease of regulation, every time the issue is raised; in other words, we see things that may be sinful that are not crimes and therefore we have no enforcement hammer in the area. That's one problem, but I'm sure the licensee sees us bringing in things he thinks shouldn't be crimes and calling them crimes. We're not all playing with the same deck of cards and rules in dealing with them and it makes it harder to resolve issues was the point I'm trying to make.

MR. SIESS: The basic question that comes up here is the NRC dealings with regulation and --

MR. JAUDON: I think we're supposed to deal with safety.

MR. SIESS: Safety through regulation. If it meets the regulations it is safe; if it doesn't it is not safe in the regulations I wish I believed that. I don't argue with what you said. I'm just saying it is not as unique as you think.

MR. JAUDON: It may not be. It seems so to us. That's all I had to tell you.

MR. SIESS: Any more questions?

MR. SIESS: Thank you.

Mr. Walker?

MR. WALKER: Under item V I'll give some general comments about administrative --

MR. SIESS: Excuse me, what would you think would be a good time for a break?

MR. WALKER: We're actually 25 minutes ahead of schedule, so --

MR. SIESS: Want to take a few minutes now and let people stretch? About 10 minutes.

(Recess.)

MR. SIESS: We'll continue.

MR. WALKER: Fine. I'll cover item Roman numeral V on your agenda, administrative and management items, and give you a general overview with some specific comments in the area of morale and employee attitude and some of those things; and then Larry Brey, Jack Gahm and Mike Holmes will cover other things under this general category. Let me say at the outset about the management and management's involvement, and I think it is probably obvious to most of you that my involvement in the plant has increased manifold in the last few months, and it became apparent to us even in the end of '84 and certainly at the beginning of '85 that we did have some problems in the area of management control, attitudes, morale, stress, and these sorts of things. Part of that came out of some audit work in the -- can you all hear me? I usually speak reasonably loud.

Out of that came what we call the Performance Enhancement Program that covered six areas all the way from training and additional personnel and procedures and scheduling and all these things that do make an organization run better, and Larry Brey will cover that in detail.

As one of you mentioned, we had had an outside contractor that helped us set this program up. It is a good program. They did a good job of setting it up. We've now brought that in-house and have one of our own people in charge of it. This is going to be an ongoing program; in my thinking, it never ends. Performance Enhancement Programs should continue on into the future. Once it is established you don't drop it. That will continue.

We've had a change in executive management. The individual involved in running the nuclear plant is no longer in the employ of the company, and on December 6 I took over the active management of the plant. The four managers report directly to me so I'm involved on a day-to-day basis.

My background is in nuclear. I loved working on the plant when it was conceived and through all of it, and I'll have to admit that sometimes working on the nuclear is more fun than some of the other things I have to do in my job as CEO of the company; however, good management would say I cannot continue to do that and I don't plan to be in direct charge of the plant much longer. I have a search under way to find a person to take over the management of just the nuclear portion of our operation, and that person will report directly to me as CEO of the company.

But in the meantime I am responsible and working on this, and frankly I am enjoying it and finding a lot of things we need to do and straighten out in the plant.

We started out with our performance enhancement program, as I said, with six basic areas. It became apparent to me, and the NRC people may have found this at some other places, there's a lot of problems with employee attitude -- and you can call it morale or attitude -- the nuclear business is a very stressful business and it is a business that younger people, I think, have some genuine concerns. There's been no nuclear plants ordered since 1973. What's the future of nuclear, am I in the right field at all? If I was a young engineer, 30, 35 years old, I might have some of those fundamental questions.

I want to know how our people feel; and it is one thing to ask the managers. They tell you but there's lots of levels in your organization that you need to know how they feel, and you would be surprised at what a good perception they have of how things are working, so we added another item to our performance enhancement program.

We hired a company called The Training Company, which works in a group basis on attitudinal problems, motivational problems, and they really get down to the roots of it. They hold focus session groups, usually running half a day and of 450-odd people; they have included over 200 of these people in those sessions, where they have actually, these Training Company people, sat down with them -- some of these are performance level people, union people -- and have them identify what are the problems. What's wrong? Why is the attitude bad?

These people, as you might expect -- this is about 40 percent of our employees, 45 percent -- really have their fingers on some of the problem areas and they have come up with 11 areas that they think we can make some improvements in; and these areas are planning, interesting enough one is NRC relationships, teamwork, career paths, responsibility, accountability, communications, technical and managerial experience, commitment to quality, executive management communication is one thing they had concerns about. And as you might expect, compensation is on that list, and facilities, working conditions in facilities. We've identified these 11 areas in the phase 1 part of the program.

The second phase is to take some of these same people and set up smaller groups, and they are in the process now of working on the solutions, and this method has the people out there that are going to have to do this directly involved in buying in and being a part of the solution. I think some of the things that was reported on, just the attitude of the people of somebody asking them, getting them involved in the process, does an awful lot for their morale. The proof of the pudding will be we come up with the solutions and we implement these things, does that really make a marked improvement in their performance, productivity and morale.

As most of you know, there are good testing procedures on stress. You can test people before and after programs like this and see what their stress levels are. We're using some of those test mechanisms. I'm very encouraged with the what I'm learning from this experience. I can't help but believe it will go a long ways towards getting our people to feel better about the job and doing a lot better job for us, and I highly recommend this type of procedure to really get down to the roots of the problem. It is not going to do everything, and you have to have the guts to back up these solutions as they come down the road.

I wanted to highlight that particular part of the performance enhancement program specifically, because I feel very strongly about it, and I think it is going to do an awful lot of good for the performance of our plant. That's obviously what we're all interested in. I would like to turn it over to Larry Brey now, and maybe, Dr. Siess, after he covers the performance evaluation you can ask him questions and I can chime in on the answers to those if you would like. I would like you to hear the complete program.

MR. BREY: About a year ago, after we had an independent assessment made of our management here at Public Service Company with the nuclear project, we instituted a very, very substantial program to improve basic areas of concern in dealing with the management of Fort St. Vrain. This was titled our Performance Enhancement Program. It's mission is to assign and implement activities that will improve the overall quality, management and operation of public service nuclear organization in a controlled, timely manner.

This program took on six specific phases initially, and it grew to seven phases with the addition of the project that Mr. Walker just mentioned. I want to go through all seven phases and hit the highlights of those areas that each phase encompasses.

The first is organizational concerns and the purpose is to take action to enhance and strengthen our organization and its method of doing business. Most of the first project is complete. If you look at some of the major items, the nuclear organizational changes, at that time, which was about a year ago, Mr. Walker brought the executive associated with the nuclear project directly under his control. This was a change in the organization. Another major change in organization was the creation of a new division whose sole purpose is to handle licensing and fuel-related activities.

The development of charters and mission statements -- throughout my presentation I'll indicate there are lots of things that have taken place, and I don't want to create the attitude that we did not, for instance, have charters or mission statements to start with. We did have charters and mission statements. We found they could be improved substantially, and that's what we undertook here as part of the first phase of this program.

Same way with communications policies. We had policies. We had procedures that interrelated the different divisions before, but we saw a need to strengthen them and we have strengthened them.

Evaluation of personnel retention. Personnel retention, as I get further into the discussion here, still remains an area that we need to improve on. Retaining people in our nuclear project, if we look at Public Service Company as a whole versus just the nuclear project, we have a turnover rate four times higher in the nuclear area than we do with all of Public Service Company.

MR. WARD: What are those numbers, Larry? Do you recall them offhand?

MR. BREY: I might need some help, but I believe in the first 10 months of 1985, in the quality assurance area, we had something like a 22 percent turnover rate. In licensing, we had a turnover rate of about 20 percent. In engineering, [illegible] I remember, it was 14 percent; and produc[illegible] guess is it was up in the area of 20 percent, and many of these are people that have a defined expertise like health physics, where they just go some other place. They will go to another nuclear plant.

MR. WALKER: Some of those are people transferring to other parts of the company. They are not leaving the company.

MR. BREY: But they have left the nuclear part of the company to go to another part.

MR. WARD: That was for an annual period, did you say?

MR. BREY: That was a summary of the first 10 months of 1985.

MR. WALKER: That's come down some, hasn't it, since then?

MR. BREY: Yes, just because of the performance enhancement program and some of the issues we're undertaking, it has come down. We hope to substantially improve on this trend of bringing it down.

The last item I have as far as a major part of the first project really tells you the type of emphasis we're putting on our performance enhancement program. We created 78 new positions within the nuclear part of the company. 71 of these 78 are filled right now. Most of the 78 are areas where high technical involvement is necessary. Good key people.

MR. WARD: When Mr. Walker talked about 450 in the nuclear program, that includes this 70?

MR. BREY: It is up to about 470 now, but out of the 470 that includes the 78 or the 71.

MR. WALKER: I think the actual figure is 475 including this.

MR. BREY: The second project deals with planning and scheduling. The purpose is straightforward. We established a master planning and scheduling function and essentially strengthened the planning and scheduling functions of the four divisions. The major areas addressed were to develop a master planning and scheduling function. As I mentioned, that has been created; and the next one is to implement divisional planning and scheduling functions. We are in the process of finalizing the implementation of the individual divisions and having their planning and scheduling functions more pronounced.

Developing outage and long-range schedules; we had done this in the past, but here again this is an area that we saw there was a need for enhancement and we've undertaken that enhancement. Improved project management techniques. In this case, primarily there's a lot of computer software out there that can help us with our planning and scheduling function, and we have looked at what's available and we are implementing what's available in the industry.

MR. SIESS: Is your outage and long-range scheduling anything like the living schedule being implemented by some of the plants that's worked without -- out with the NRC and your initiatives and their requirements are being integrated, either living schedule or ISAP type things?

MR. BREY: The question that came from the NRC, because we're in the formulation phases of our planning and scheduling function, we chose to answer their questionnaire. In fact, we said, please let us have a number of months before we come to grips with it. It is a living schedule. That's where we stand.

The next project, I guess, preventive maintenance. Again I want to stress the word improved preventive maintenance. I don't want to leave the impression we had no preventive maintenance to start with. That would be a misnomer. We had a preventive maintenance program. We saw the need to strengthen it and we have strengthened it and are continuing to make it even stronger. We've established a maintenance planning organization and are in the process of revising our preventive maintenance procedures to add procedures for critical components, and critical components are those components that we feel are necessary to improve plant availability, not necessarily tied directly to safety, but in this case plant availability.

Also we were adding post-maintenance testing into the revised preventive maintenance procedures. This is a recent add-on, to give you an idea that the performance enhancement program is going to continue. It will never stop, at least we don't feel it will ever stop. We saw a correlation with our management issues with Toledo Edison, and when the Davis-Besse incident happened and the NRC reviewed that incident, I believe that the summary of their review had 18 points where they saw that there was a need to improve in the Toledo Edison area. We have taken those 18 points and we've incorporated them in our performance enhancement program to make sure that we have not overlooked something, that we have taken what measures we can to strengthen our ability to handle our nuclear project in this regard.

MR. WARD: You mentioned earlier that there are 78 technical positions being added in the overall program. How many of those are in maintenance?

MR. BREY: I don't know the breakdown as far as the individual areas. First of all, there were 78 positions, not necessarily all of them technical. The majority of the 78 were technical. Can anybody help me?

MR. GAHM: I think 56 --

MR. BREY: Of the 56, of those that were maintenance --

MR. GAHM: I would say around nine.

MR. WARD: As I understood, the thrust or part of the thrust of Toledo Edison's problem in maintenance, it was a pretty major increase in the staff but there was sort of an attempt to, what we might call professionalize the maintenance program, bring in as maintenance superintendents engineers and people who would participate in professional activities in ASME and that sort of thing related to maintenance. Is that sort of idea part of what you are thinking about or --

MR. GAHM: We did add a major amount of maintenance engineers to our plant engineering staff before that function to interface with our major mechanics on a day-to-day basis, to make sure there is professionalism. In addition, we've rewritten our maintenance procedures to incorporate human engineering factors in those maintenance procedures to make them more usable.

MR. WARD: What about the -- people talk about the ratio of resources going into preventive versus corrective maintenance. Do you have a number for that now and do you have a goal for what that should be or what you would like it to be?

MR. GAHM: Well, what we're trying to go to?

MR. WARD: Yes, what is it today and do you have a goal that's different from today?

MR. GAHM: I'm not sure what the ratio is right now.

MR. NOVACHEK: I don't think we've looked at it in that much detail. We're trying to establish the improved preventive maintenance program, and as soon as we get that going we'll be able to come up with some sort of estimate.

As soon as we implement all the improvements, which is in the very short term, we will take a base line of what those ratios are and then use that as an indicator as to how the program has improved.

MR. SIESS: Would you identify yourself, please?

MR. NOVACHEK: Frank Novachek, with PSC.

MR. BREY: The ratio is on a significant upswing, obviously. I can't tell you what the goal is as far as people or resources are concerned, but just by the creation of this organization and creation of this project within the performance enhancement program, it has to be a much better ratio in the end than what we started with. I can't tell you what it is.

MR. NOVACHEK: Larry, in support of that we're reviewing the efforts of other plants to determine what a realistic goal really is. We have been in the doldrums for such a long period of time it is going to take awhile before we reach the kind of goal that maybe Arkansas has, but we're trying to research other plants at this point to determine what a realistic goal is for the short term.

MR. WARD: Sounds good.

MR. BREY: The fourth area is to upgrade nuclear policies and procedures, and I've indicated six different sets of procedures here, all six areas we have procedures in the past. We saw a need to improve on them and we are in the process of improving on them.

MR. WARD: When you talk about emergency procedures are you talking about site procedures or control room procedures?

MR. BREY: Control room procedures.

MR. WARD: Thank you. How do you -- there's been -- for the light water reactors in the country there's been fairly extensive programs in the process of developing emergency procedure guidelines, and then human factors guidelines, and finally emergency operating procedures for each individual plant, and I guess that's been partly successful so far. I'm not sure how well it is going, but how have you participated in that sort of effort here or is there a parallel?

MR. BREY: We're using outside help in rewriting our emergency procedures. I don't know if you want to go and can give more detail on that contract.

MR. GAHM: At the present time we're really evaluating the bids we just received on this. We're looking at companies such as Westinghouse, General Electric, Impell, ProtoPower, companies that have developed emergency procedures for other plants to get their feedback and their approach to developing emergency procedures. We anticipate having those probably completed within the next year.

MR. WARD: Do you have -- in the light water reactors, the plant specific simulators figure fairly importantly for the training operators but also they are being used as a tool to, I guess they call it verify and validate the procedures. How will you go, since you don't have a plant specific simulator, how will you go about training and also validation of the procedures?

MR. BREY: We do not have a plant simulator per se. We don't have one that's computer controlled that we can put ourselves into an accident condition and watch the control room response, so to speak. We do have a rebuild of the control room, though. It is not tied to any kind of a computer system except a very small portion of it, but we would walk through the emergency procedures on that mockup and we would train on that mockup.

MR. WARD: Have you done that so far? Is that part of the existing operator training?

MR. BREY: That is part of the existing operator training and it will continue with the advent of the new emergency procedures in this case.

MR. WARD: Thank you.

MR. BREY: Speaking of training, that's number 5 in our projects. Again, we had training programs in all the divisions. We saw a need to strengthen them and we have undertaken a sizable improvement in our training program. It was mentioned earlier about INPO accreditation of operator positions. INPO was in here within the last month. We anticipate their accreditation to come through probably within the next two months. All of the remaining nonoperator positions, we anticipate INPO to be in here to look at our accreditation program by the end of 1986. The third item I have here is the training and support divisions and this is a substantial improvement in the training in the quality assurance, nuclear engineering and nuclear licensing areas.

The sixth project deals with plant conduct of operations. The purpose, I guess, is to correct root causes of deficiencies in operator responses as well as obtaining improvements in our facilities, primarily here on site. We have a major effort under way to standardize our identification of components in the plant. All the components have been identified in the past, have tags on them, but just as operators we saw the need to improve this and we are improving it substantially. Defining plant management responsibilities and shift operator procedures, again, we had these defined in the past, we have improved the definition of our plant management responsibilities and our operator on-shift requirements.

Evaluate personnel facilities. If you look over there, you see a lot of tailers, and they don't lead to a feeling of permanency. We are right now evaluating the addition of a new maintenance shop to the tune of some $6 million. If that is built, we'll end up opening up space in our administrative area in the plant to provide new facilities for our technical staff.

We've also established a component shelf-life program for components that we use as spare parts. We had Sergeant Lundy put this program together.

MR. SIESS: What proportion of your support staff is on site?

MR. BREY: Proportionately I would say of the 470 people, about 80 percent are on site. We have nuclear licensing and nuclear engineering, we have both site staffs there and non-site staffs.

The last project Mr. Walker went into in considerable detail, so I will not discuss it unless there are more questions about it, but this is the total responsibility management that we're utilizing the training company to help us with. This is a big program that we are intimately concerned about, and we have in the last three months spent a considerable amount of time identifying the areas of concern and knew we're in the process of defining corrective action measures.

MR. WARD: How are the employees as a whole -- I guess from Mr. Walker, what Mr. Walker said, I gather the employees are reacting favorably to it, but there can be some negative reaction and, I guess, scoffing on the part of employees at this sort of effort. Are you running into that?

MR. BREY: I think that you are going to get a cross-section of employee attitudes. The proof of the pudding is do we really mean business? Are we going to take these corrective measures? Are we going to see them through? At this point in time we've identified the problem areas associated with our total responsibility management, morale as such. We are -- the employees themselves are in the process of identifying corrective action measures to handle the 11 areas Mr. Walker mentioned. When that is completed, which we anticipate within the next three weeks to be completed, then it will be up to us to implement the corrective measures, and in some cases that's a very long-term situation. I can see this going over the next year and a half, just the implementation phase, but to me, the key to, say, some employees that might scoff at the issue, they just want to be shown. They want to be shown that we're going to resolve it. That we mean business, and we do.

MR. WALKER: Let me address that a little too, Dave. The managers are, of course, a lot closer to the people, but I still have noticed a change, and let me give you a couple of examples. I normally follow management procedures for communication. I don't let everybody call me or write to me, but in the last couple of months -- I got a letter from the home maintenance group the other day, some 20 names on it with some suggestions of what they want to do. They sent a copy to the appropriate manager but made sure I got it. I got another one on housekeeping and the use of laborers in an area that's not a lot of dollars signed by three union people that wrote me directly.

I had a few phone calls. One guy called and thought maybe our motivation stuff was a little strong. He called me up at 7:30 one morning. I think he was surprised to get me on the phone and I listened to his remarks and indicated that we all had -- different things motivated different ones of us, and to come up with a program that would satisfy every individual from a motivational standpoint was improbable; and he thanked me very much and I don't know how he's reacted in some of the focus groups, but it would be interesting to see if his attitude has changed.

Those are a couple of examples that I know of personally in the last couple three weeks.

MR. BREY: That takes care of the seven projects. To give you a brief summary, of where we stand with the performance enhancement program, we're a year into the program. We originally started with 34 subprojects. Because this is a program that continually changes, in the last year we've increased those 34 to 42 projects and you can see now 17 of the 42 are now complete. Environmental qualification of electrical equipment issue has impacted our progress of this program. We set out a year ago with some pretty strong schedules to meet the program, but EQ has caused that to slip just a little bit.

Other scheduled slippages -- again, increasing the project scope and new projects going from 34 to 42 projects means, again, taking our resources and reapplying them to 42 projects rather than 34, and also the staffing and resources issues, we have 71 of the 78 new people, yet we still have and continue to have between 25 and 30 openings all the time in the nuclear area, so staffing does impact on our schedule.

We were concerned about where we were going with the performance enhancement program, so about nine months into the program in late 1985, we contracted S.M. Stoller Company to provide an independent evaluation of, are we really making it? Are we achieving the goals that we set out initially in the performance enhancement program, and this is a multi-year effort and just being nine months into the effort, this was pretty well their summary statement. S.M. Stoller concluded that the Performance Enhancement Program is a well thought out and well-structured program, if carried through with a strong sense of management commitment, which appears to be present. Its implemetation should improve the conduct of the nuclear operations substantially.

However, they could see slips in the

implementation schedule and also saw an excessively high loss of people in the nuclear area, which could have an impact on our performance enhancement program. They saw a need to resolve this and actually section 7 of the program takes into account the human resource issue, so we hope that we're on the right track and we fully intend to make this program do what it was initially intended to do.

That pretty well concludes my comments on this substantial program. This was added about a month before the Stoller audit was complete. I believe it was in the October-November time frame of 1985 that we felt that we must address the morale issue. It first came to us because we seemed to have problems retaining people, so we started looking at morale, and it was then, in late 1985, that we contracted with the training company to undertake that human resource issue. The next person is Mr. Gahm, who will give you an update of the plant status.

MR. GAHM: Good morning. Prior to me going through the plant status -- and the plant status will run basically from the last visit of ACRS which was May 17, 1984, up through 6:00 this morning -- as I go through the plant status and what's happened over the two years, there will be a lot of technical issues that you'll want a lot more detail on. Farther on in the agenda for today and tomorrow we'll cover these areas in great detail.

In May of '84, the plant had just went critical, right after our third refueling when ACRS met out here. On June 12 of '84, we synchronized the mach:ne and put the turbine on line. On June 23 of 1984, we probably had one of our most long, serious upsets that we have had in the plant. We had a sudden 10 pressure relay that was new that was installed due to the modification of the third refueling. It had an internal fault in it and failed causing an upset on a circulator, which in turn injected large amounts of moisture into the core. This moisture injection resulted in a very high pressure scram on the reactor. During that scram, six of the 37 control rod drives failed to automatically insert. Let me stress, though, all six failed to insert; the reactor was in a cold shutdown condition after the 31 rods went in. By operator action, within 20 minutes, the other six rods were manually driven in the core by normal means.

MR. SIESS: How many rods does it take to get the cold shutdown?

MR. NOVACHEK: Depends on the fuel cycle.

MR. SIESS: Are there circumstances under which the 31 would not have gotten you the cold shutdown?

MR. GAHM: Yes, there would have been. After this upset, the plant remained shut down and in early July of 1984 we started looking into the probable causes of why these six rods failed to go in. That investigation went through July, probably to about the latter part of October of '84. During the investigation of the failure of the six control rods to automatically insert, we had a control rod absorber cable fail during the removal from the core. This was not a separation of the cable; it is actually one strand on the cable fraying and then balling up into the penetration that it goes into up on the drum. This evaluation, although it shows up here, we determined stress-corrosion cracking on that particular cable was not determined at this time.

It was determined later, toward the latter part of October, first part of November. As part of our November 1984 surveillance testing, our reserve shutdown materials in the CRDs, we're required to test two shutdown hoppers, a high boron content and a low boron content. During this test, one of the hoppers failed to discharge all the reserved shutdown materials completely. This was caused by an indication of moisture in the hopper which caused a binding together of the boron balls, which Mr. McBride will go into in great detail this afternoon.

MR. WARD: If you go to the June 23 event, the fact that all the rods didn't go in, that didn't call for firing the shutdown hopper?

MR. GAHM: No, it did not.

MR. WARD: Under a circumstance, if you had been at a different point in the fuel cycle where more rods would

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have been required --

MR. GAHM: The appropriate operator action at that time would have been firing it up.

MR. WARD: If it was just one hopper, would you have achieved cold shutdown with the failure of the hopper plus the failure of the five rods?

MR. GAHM: Yes, we would have. We can have one hopper out of each group -- that's two hoppers total -- inoperable, even when powered for tech specs and still remain shut down. The criteria is that they must be operable for the built-up protactinium in the core seven days later.

MR. SIESS: You were able to manually insert those rods in 20 minutes which gave you a further margin.

MR. GAHM: That's correct. It takes about three minutes per rod to electrically drive them in.

MR. SIESS: The core heats u. in 20 minutes --

MR. GAHM: In November of '84 I guess I could say I was scratching my head pretty hard. I had cables that were balling --

MR. SIESS: All these of these things -- I believe I'm correct -- could be attributed to moisture in the core?

MR. GAHM: They could have been attributable to the moisture in the core, particularly, the hopper was attributable to the moisture in the hopper. Failure of the rods at this point -- we're not sure at that point why those rods had not inserted. We talked a lot about what we did in that process, but we never came to the real conclusion that the moisture drastically affected the operation of the rods or whether it was a build-up of the barite wear on the bearings. In November of '84 we made the decision to replace all the cables in all 37 control rod drives, replace all the reserve shutdown material in the 37 hoppers and to totally refurbish the drive train on all the control rod drives.

During the June 23 upset, it appeared that A circulator went through a large thermal shock somewhere. At that time, we ended up having a lot of moisture build up in the penetration on A circulator. We pulled A circulator out and determined there was a failure on a four-bolt flange on the high pressure water bearing system to that. Since we had just put that circulator in the core during our third refueling which ended just prior to this event, we did not have our spare circulator ready, so we sent the A circulator back to GA to determine what the problem was and correct it. They identified that one of the bolts in the four-bolt flange had failed by a structural failure, but not by stress-corrosion cracking.

During the reinstallation of the circulator, one of the bolts on the hold-down bolts did fail and later investigation determined that it failed because of stress-corrosion crack. When we identified we had failures on stress-corrosion cracking we decided to remove one more circulator and identify whether it had stress-corrosion cracking on any of the substantial bolts.

We found one other indication on that and made the determination to take all four circulators out, replace all the bolts that had stainless steel bolts in with Inconel 618, if I'm not mistaken. 718, okay. The remainder of the first six months of 1985 was primarily to work on the circulators and work on the control rod drives.

MR. SIESS: How many times have you changed out circulators?

MR. GAHM: I'm trying to think. I think we've taken three out to be refurbished on a routine basis and we've had the four of them out this last time here, and I think that's basically all the time we had them out. That's over the 17 years I can remember.

MR. SIESS: This operation has worked as planned pretty well?

MR. GAHM: Yes.

MR. SIESS: Is it getting any easier?

MR. GAHM: After you do four in succession, yes, it is easier. It got down to about a six-week turnaround from the time you took it out and put it back in. The first probably took 12 to 16 weeks.

MR. SIESS: If you had your spare right there, how long would it take?

MR. GAHM: Still about six weeks from start to finish. We have the spare now completed and we have bought the internals for another circulator so we'll have spare parts.

As of June of 1985, everybody was feeling very good that, one, we had the control rod drives refurbished, they had responded well to the testing during refurbishment and all four circulators had been repaired. We then received authorization from the NRC to take the plant critical on July 20. This was to a 15 percent power level. The 15 percent power level was primarily based on the fact that the environmental qualification issue had raised it's head sometime in June of '85.

On July 23, we again had another moisture ingress into the core. We took a normal shutdown on that and we remained shut down until we provided justification for the 8 percent release to clean the core up. We took the plant to 8 percent power over a 30-day period and remained there until it was November 7, until we actually shut down, to start doing some environmental qualification modification work. During that period of time in September, we requested an extension on our environmental qualification from November 30 and we received that from the Commission, to be extended to May 31. After the Commission approved that we worked with the NRC Staff until the 14th of February of this year, resolving some of their technical concerns about going back to 35 percent power.

After we resolved those things, the plant went critical on Valentine's Day of this year. The plant at the present time is still in a power ascension, a very slow one to say the least, because we're removing the reminder of the moisture in the core at the present time. The current status of the plant as of this morning at 6:00 is that the reactor power is at 12.3 percent. Our primary coolant flow is 39.7 percent. Reactor dew point is 32 degrees F. Our average core outlet temperature is 719, Inlet temperature is 490 and average fuel temperature is 683. That was at 6:00 this morning. These values have changed now because we're now proceeding to go through boil-out and hopefully will be through boil-out at about 23 percent power at about 4:00 or 5:00 this afternoon. Like I said at the start, you'll get a lot of technical information regarding all the -- I won't call it operating experience -- maybe, maintenance experience we have been through during this session.

MR. SIESS: As far as plant components are concerned, you are operable. You have two limits. One is to get the moisture out and the other is the limit on the environmental qualifications?

MR. GAHM: That's correct.

MR. SIESS: When you get to 35 percent, now, if you don't complete your environmental qualification paperwork by May 31, do have you to go back down?

MR. GAHM: Yes and we will not have it all completed by May 31. We plan on coming down May 31 to finish installing the modifications in the plant that we cannot do right now. The main purpose of the run now is to get the moisture out of core, get the plant on-line and make some electricity. We can make about 105 megawatts per hour.

MR. SIESS: Just don't put any more water in it the next time you shut it down.

MR. GAHM: If you got the solution for that, I would like to hear it. Mike Holmes is now on tap. He's manager of licensing.

MR. HOLMES: I'm Mike Holmes. I'm manager of nuclear licensing for PSC. Several of the topics I'm going to discuss concerning the status of regulatory issues, Ken Heitner has already touched on. I'll try not to dwell on any of the points that he has covered, but perhaps we can add a little to some of the questions that were asked. I would like to emphasize at this point that there will be some additional engineering and technical discussion of several of these programs that we have in progress later on by members of the engineering staff, so my topic will primarily dwell on interactions we've had with the NRC's Regulatory Staff and setting forth the ground rules for these programs. The first topic includes our Appendix R, fire protection program. To summarize this, under 50.48, we were doing the original licensing of the plant and the original bulletins that came out on the subject of fire protection evaluated under branch technical position 951 and that only required us to consider three sections of Appendix R, specifically sections 3-G, 3-J and 3-O.

MR. SIESS: That was for your original license?

MR. HOLMES: As part of the original license plus part of the fire protection requirements that came out after Browns Ferry.

MR. SIESS: When you originally licensed, there was no Appendix R; right?

MR. HOLMES: Right. We had the regular fire protection discussed and --

MR. SIESS: When did you get your own well?

MR. GAHM: December 73.

MR. SIESS: The branch technical position came out before Appendix R did. When did that come out?

MR. HOLMES: Late '70s. '78. Under 50.48, which invoked Appendix R and having been evaluated under branch 951 there were three sections of Appendix R that applied to us. After the interaction with the NRC Staff at the time, those subsections were dispositioned as as follows. 3-G, which dealt with the safe shutdown cooling capabilities fire protection divisions, it was agreed that that did apply to our plant as did section 3-J concerning emergency lighting provisions. I'll get to this third bullet in here. 3-O collected an oil collection system for reactor coolant pumps. Having no pumps and no oil collection systems on our helium systems that have bearings, the Staff agreed that did not apply to our plant.

Early in the Appendix R inspection process, a number of questions came up on various plants concerning section 3-L, which dealt with alternate shutdown cooling systems which, at the time, we did not really look at. Having our alternate cooling method system and looking at the provisions of section 3-G, particularly section 3-G3, we thought we were in pretty decent shape and responded to some of the initial inquiries on that basis. Once the inspection team said, wait a minute, we have a 3-G3 alternate system, then that invokes 3-L, we looked at 3-L and ran into some problems immediately.

After some extensive discussions with the NRC Staff, it was basically concluded that 3-L was indeed applicable to water reactors and that in lieu of 3-L, some criteria were developed, specifically for the Fort St. Vrain plant, which gets me back under the last bullet under the applicable criteria. We negotiated some specific fire protection criteria requirements for Fort St. Vrain and that will be the subject of the next two slides.

The first set of criteria concerned our congested cable area situation and this is where, of course, after a number of millions of dollars of plant improvements and so forth, we did install our alternate cooling method system to protect against fires in the three-room control complex. There were a number of foyer protection provisions -- detection, suppression, prevention -- installed in the three-room control complex and the walls on either side of that complex where congested cables did occur as part of the final resolution of the criteria question, the NRC did accept under Appendix R provisions that were in place for the three-room control complex as meeting the intent of the fire protection regulations.

Basically, that entailed in the event of a catastrophic fire, even with all the fire protection provisions, that the consequences to health and safety of the public would be limited to the consequences of our design basis accident number 1 to briefly discuss that that of course involves our permanent loss of forced circulation accident, which happens over a very prolonged period of time, several days. Initially in the accident, forced circulation is lost for the first 30 minutes the core actually cools down while the graphite heats up the fuel temperatures. The fuel temperatures come down to the graphite temperatures -- if we're not able to restore forced circulation after two hours, we would then begin to depressurize the plant, complete that process before any significant amounts of fuel particle coatings have failed. It will be basically a half day into the accident that the substantial amounts of fuel particle coating failures would occur and fission particles be released into the superior and over the course of the accident, a very minute percentage of those fission products will permeate through the PCRV concrete under worst-case scenario conditions and result in a very, very small fraction of the 10CFR guidelines of those radiation results ever reaching the public.

Basically, again, the fire protection provisions and the ACM and the equipment that the ACM operates, we would have sufficient reactivity control provisions to maintain the reactor at subcritical. We'd purify through training and that would, in turn, clean up the majority of the primary coolant that would be released from the plant. We would use the prestressed concrete reactor vessels' liner cooling systems to remove decay heat from the core and we would have sufficient control and process variable monitoring instrumentation and the various support systems that we would need to shut down the -- cool down the plant using the liner cooling system, so the three-room control complex -- that was the set of criteria agreed upon for the Appendix R situation.

MR. SIESS: You have completely lost the three-room control system? But the rest of the plant is still intact and you need some balance of plant items to do the last bullet right there?

MR. HOLMES: ACM power is provided to the various pumps, whatever valves might be required to send fire water through the liner cooling system.

Primarily, this is an -- it is not a powered depressurization. It just uses the PCRD pressure throttled initially to force it through the helium purification train beds. We would supply liquid nitrogen to the charcoal temperature absorber bed to keep it cool until the depressurization was complete. After about 10 hours into the accident we would be down to roughly atmospheric pressure, maybe 5 psi above atmospheric pressure and at that point, bottle everything up and write out the accident and that's again when the fission products would be released.

MR. SIESS: You're satisfied that you have adequate means for safe shutdown if the fire is limited to that area?

MR. HOLMES: Regardless of the fire protections in that area, if there were a catastrophic fire, the public health and safety would be protected using these systems.

MR. SIESS: The next slides will address the balance of plant?

MR. HOLMES: Yes.

MR. WARD: The depressurization of the helium system has to be by venting to the atmosphere through the purification system; is that right?

MR. HOLMES: Yes. Well, that's the type of depressurization that we used for this accident. It is necessary to get the PCRV depressurized so that the amount of core heat that's transferred to the liner cooling system is within manageable limits by having less transfer helium in there. So it does not overwhelm the water going through the tubes to keep the liner cool. The 3/4 inch steel membrane throughout the PCRV superior is intact, as is the concrete during the course of the accident, so we have two of the three fission product barriers.

MR. SIESS: You have to vent helium?

MR. HOLMES: Yes, to keep the transferring into the liner at manageable levels.

MR. WARD: You take credit for some removal of noticeable gases?

MR. GAHM: That's true.

MR. HOLMES: We have other accident conditions where we assume the whole primary coolant inventory is lost, but in this case it is cleaned up before it is released and the consequences to the public are extremely mild.

MR. WARD: What doses do you get at the plant compared to the 10CFR100 levels?

MR. GAHM: I think it is a factor of 30 over 100 --

MR. WARD: On both the whole body and the thyroid?

MR. HOLMES: This has other miscellaneous information on it, but for whole body and thyroid for DBA 1 -- we're talking those levels of man-rem, and versus 10CFR100 guidelines, you can see that we're orders of magnitude below the 10CFR100 guidelines. If we release the primary coolant with no cleanup, we're obviously above DBA 1, but that's what we call our maximum credible accident.

MR. WARD: I'm confused. Which is the one we were talking about?

MR. HOLMES: DBA 1 is loss of forced circulation, completely, of forced circulation.

For the balance of plant, there were another set of criteria that were discussed and finalized with the Staff as far as how we would respond to a fire, major fire in that portion of the plant. In this case, it was agreed in the regulations required that the accident not result in consequences greater than normal loss of off-site power, which are essentially fire up the diesel generators and the plant rides on all of its emergency systems and basically nothing happens.

In our case, we agreed with the Staff that we would not incur any fuel particle damage for our ceramic-coated fuel. That translates into fuel temperatures not exceeding 2900 degrees F. Or we would have cooling in place to keep the fuel temperatures below the particle failure temperature. Again, there would be no simultaneous disrupture of both primary coolant PCRV liner figures barrier liner and secondary containment enclosure for the PCRV, and therefore no unmonitored radiological releases.

We would use our reactivity control systems to maintain criticality. We would maintain the PCRV liner integrity and structural integrity to keep the pressure boundary containment intact. We would use forced circulation cooling to remove decay heat versus the liner system for the control room type fire, and again, we would maintain the necessary process variable, instrument control functions. So this is basically a forced circulation cooldown system. Even the enhanced fire protection in the three-room control division, were we to get a catastrophic fire we would protect the safety of the public with the liner cooldown.

MR. SIESS: For the catastrophic fire in the three-room complex, you have much more generous criteria than you do for this one.

MR. HOLMES: This says basically no significant plant damage. There would probably be some possible, or thermal barrier might heat up more than one might like, but the liner itself would be intact. The PCRV concrete would be intact. We would have forced circulation cooling going. The fuel would not heat up to the point where the ceramic coatings might start failing. Again, basically, there would be no difference than the consequence of a loss of off-site power.

MR. SIESS: Why more restrictive criteria for this accident than the other, because this is more probable than the other?

MR. HOLMES: Given the extent of the fire protection measures we took around the three-room control complex, I believe that's a reasonable conclusion. We don't have that amount of detection equipment and suppression equipment and so forth in the balance of plant, and Fred Tilson in a later talk will get into the details of what fire protection measures we've started to implement in the balance of plant in order to meet this criteria.

MR. SIESS: I think I understand, but I guess I'm not sure. These consequences -- the other consequences are negligible. These are even smaller?

MR. HOLMES: Right. These are almost nonexistent. The balance of plant -- was basically agreed that it would be consistent with the Appendix R treatment of most of the plants.

MR. SIESS: I'm trying to figure out what 10CFR is the same as.

MR. WARD: Is that the Staff's argument that a fire would be more likely in the balance of plant, therefore, more restrictive consequences permitted?

MR. SIESS: We'll accept any volunteers from the staff.

MR. WARD: They will have to be a GCR specialist.

MR. SIESS: If Staff doesn't have anybody here that knows the answer, would you take it back home with you and see if somebody might provide us an answer?

MR. HEITNER: Let's do that. The reason is there is nobody here that I know who wrote that and --

MR. HOLMES: From Public Service Company's standpoint this touches on the question you raised earlier: Is it the NRC's business to protect our investment in the plant to protect the public health and safety? We feel the public health and safety is protected both ways for both sets of criteria.

MR. SIESS: The relative consequences are much more different from a water reactor than for gas? I don't know. After all, Appendix R, I can assure you when they wrote that they were not thinking of Fort St. Vrain. They didn't think of Fort St. Vrain until a few years afterwards. The reason -- it might be valid for water reactors and not for Fort St. Vrain or they might be equally valid. If they can get something in writing that doesn't take a tremendous job, fine. If not, maybe we can have the fire protection subcommittee do something.

MR. HEITNER: Why don't I -- at the time, I believe, that we gave this specific interpretation of Appendix R that was with Fort St. Vrain, I think we also had an evaluation that accompanied that. Why don't I provide you with a copy of that initially?

MR. SIESS: Why don't you look at that and see if it answers the question?

MR. HOLMES: The next subject on the agenda that I'm going to talk about concerns our Fort St. Vrain EQ program and, again, I'll take this up to and through the point where I'll be discussing most of the interactions that we've had with the NRC Staff, and Mike Niehoff will have a later talk on the actual implementation and status of the program. This will touch on some of the questions that were asked earlier.

The first slide concerns our original Fort St. Vrain environmental qualification program that was established going clear back to about early 1970 when we received a question concerning environmental qualification during the original licensing of the plant. VNGA put together an environmental qualification program in response to that question that was reviewed by the Staff, and as part of supplement number 1 to the safety evaluation, the Staff safety evaluation for the plant was looked at again in about 1977 going into 1978.

The fundamentals of that program, number 1, we did have a combination of both automatic and manual actions in response to emergency line break. We do have automatic detection system, group isolation system in the reactor building to detect high-energy line breaks and isolate the subject loop. That covers most of the high-energy piping systems in the reactor buildings. There is some piping that is not isolated. The valves are near the helium circulators.

Basically, between the automatic actions and the manual actions that would have to be taken to isolate a leak, there was determined at the time that in roughly four minutes the operators could isolate a leak. Subsequent to the isolation we would use our safe shutdown, forced circulation cooling systems using fire water, if none of the other defense-in-death options were available. This is fire water to the Pelton wheels, through the steam generator, at least one of the four steam generator sections, forced circulation cooling.

MR. WARD: In the first item, what are the assumptions made there about the equipment? Operator actions are required, but is there a single failure of equipment that can be tolerated under those circumstances or does everything have to work?

MR. HOLMES: There are redundant, a forced circulation cooling systems --

MR. WARD: I meant in the isolation.

MR. HOLMES: Not everything is redundant there to isolate it. There is mechanical valves that would need to be isolated. The profiles that would result from this four-minute leak covered by this one bullet down here, we had very high peak temperatures for this program that we did achieve during a 30-minute test qualification test that the equipment was subjected to. This is both mechanical and electrical equipment. With our new proposed program, well, just about everything you see here no longer applies and I hadn't intended to dwell on the old program at this point, but we did have some very high temperatures during this four-minute isolation.

MR. SIESS: Reheat steam is what, 1000?

MR. HOLMES: 1000 degrees Fahrenheit, yes, as is the main steam.

MR. SIESS: But the equipment doesn't reach 1000?

MR. HOLMES: Not in four minutes.

MR. WARD: My specific question was that you calculate these temperature profiles, but do you assume that there's a single failure in the equipment that's being used to make the isolation? Or would the temperature profiles be worse if certain single failures occurred? Apparently they would, I guess.

MR. GAHM: The original program was based on meeting single criteria, but it was based on the fact if you did experience single criteria, you could isolate the leak under any circumstances by manual action within four minutes. Most of the valves, while they are single valves, do have dual electrical actuators, so even on the automatic system we're able to meet the single failure criteria in terms of the electrical side of those valves. Not the mechanical side. We are able to meet single criteria on the electrical side. For the other, we depended on the four-minute manual-operated. Some of those actions were in the control room.

MR. HOLMES: The worst-case harsh environments involved the rupture of a cold reheat line and the turbine building involved the rupture of a hot reheat steam line. On the subject of equipment aging, which has been an issue in recent times, the initial PSC assumption was that since more of the equipment was in routine operation and accessible for maintenance, that aging was not a concern.

MR. SIESS: Mr. Heitner mentioned aging in two steps, the pre-aging I would call it, normal aging, and any aging under this harsh environment. Wouldn't the aging under a harsh environment be covered in the equipment qualification?

MR. HOLMES: Obviously during this 30-minute high temperature test, there was that amount of aging during the actual test that did go on. These tests, which were largely conducted in, say, the mid- to late-1970s, did not involve pre-aging of the equipment that was being tested. That particular requirement wasn't in effect at that time.

MR. WARD: I don't understand the last statement up there. Do you still believe that that's true?

MR. HOLMES: No. I need to get to my next slide. We're not trying to sell this program to anybody at this point in time.

MR. SIESS: That's where you were about --

MR. HOLMES: About January of 1985. Prior to that time we had had some discussions with NRC Staff, but the concerns with that program really were not put in writing until January of '85. That's the subject of this slide.

During the period from about January of '85 through June or July of '85, the NRC Staff finally took a good hard look at our environmental qualification program and came back to us with a number of concerns that they had with the original program and concept. The first Ken did talk about. In response to the Three Mile Island accident situation, the NRC Staff doesn't feel comfortable in assuming that the operators can take any substantial actions for a period of at least 10 minutes at the onset of an accident condition, and that, of course, was at odds with our four-minute assumption. So that created a major impact on our program.

There did develop a concern with the access that may have been required in certain portions of the plant to take some manual actions, depending on where the harsh environment accident was and where the equipment that we needed to put into play at that time in the accident involved. That ended up being a concern.

Equipment testing was of too limited a duration to show that the equipment was qualified for its required operability time during the prolonged accident period. In our particular case, given the event that in the containment building we have temperatures that don't hang up for a long period of time, but profile evaluation that we've done in the last year would indicate that over a period of, say, roughly 12 hours, the temperature could be above ambient after 12 hours, we start getting back down to the normal ambient types of conditions.

MR. SIESS: You're talking about hours, now, hours at lower temperatures?

MR. HOLMES: With our new program, this includes our automatic steam line isolation system, the ambient temperature; the temperature gets back down to roughly 135 or 140 degrees within an hour, but that of course would still involve some accelerated aging, but after 12 hours, it is down to less than 100 degrees Fahrenheit or back down to normal sorts of temperatures for a power plant.

So there's a concern about having tested the equipment for too limited a period of time to show its operability during the entire course of an accident; and lastly that we had not treated equipment aging properly when the concern originally came out.

With those concerns in mind, we developed the basis for the present environmental qualification. That is under way.

MR. SIESS: Is there any standard for a proper way to treat equipment aging?

MR. HOLMES: There appears to be a cross-section of alternatives. We've had some extensive discussion with NRC technical staff on the proper treatment of aging for Fort St. Vrain, and I'm really not qualified to get into the details of what's right and what's the wrong way to treat aging.

MR. SIESS: Some of this is electrical equipment, I assume?

MR. HOLMES: All of it is.

MR. SIESS: Does IEEE have any standards on how to handle aging?

MR. NOVACHEK: Yes, IEEE covers the pre-aging and the actual test sequence you would go through. In terms of a calculation type of approach we're using the methodology as discussed in the DOR guidelines.

MR. NIEHOFF: There's no standard on the calculation, though?

MR. NOVACHEK: Not that I'm aware of.

MR. HOLMES: We came up with a number of bases for a reformulated program. Concerning the 10-minute operator reaction time policy or first determination was that electrical equipment could not be qualified in our steam conditions to survive at a peak temperature of a harsh environment for 10 minutes. Our real margin at our plant is associated with the recovery from a loss of forced circulation accident, we basically have 90 minutes to establish forced circulation cooling from an accident that would occur at 100 percent power level with worst-case core temperatures and so forth. We have 90 minutes before fuel damage would start to occur again. Given these two facts --

MR. SIESS: Back to the basic criteria set up for this initiative, 2900 degree limit?

MR. HOLMES: The 2900 degree limit is for no fuel damage. On a total loss of forced circulation it takes us 90 minutes to get to that temperature.

MR. SIESS: 2900 degrees is the balance of plant criteria?

MR. HOLMES: We have 90 minutes to establish this forced circulation cooldown for fire also. Same basic accident situation.

So based on these two considerations, the decision was made that we need to automatically initiate a loss of forced circulation cooling, temporary, upon detection of a high energy line break. In other words, if any sort of substantial steam line or high energy line break it can all ball up fast.

At that point in time we have 90 minutes to restore forced circulation cooling using whatever combination of equipment is available, and two redundant sets of that equipment involve forced circulation cooling using firewater, and this is the body of our environmentally qualified equipment. We have, then, two redundant safe shutdown forced circulation cooling flow pads using firewater. As part of the overall set of criteria here, we agreed that manual action would only be taken from mild environment areas.

MR. SIESS: What's the definition of mild environment? Is that 130, 140 degrees?

MR. HOLMES: No, no, much less than that. We are not talking about ice vests or anything of that. We do have those in place for use if you want to, but we're not trying to access 135 degree areas to take manual actions.

MR. SIESS: Is this the steam line break detection and isolation system that we're talking about now?

MR. HOLMES: Yes. The in-line rupture detection and isolation system is the one that would be utilized for this.

MR. SIESS: You'll tell us later just what it does?

MR. HOLMES: All the technical details, yes.

MR. WARD: Would you tell us what it means to initiate the LOFC detection?

MR. HOLMES: Basically, you shut -- well, not all, a cross-section of the high energy line isolation valves of the plant are shut in order to isolate any source of water or steam to a leak. That in turn shuts off the steam to the circulator drives and results in the loss of forced circulation.

We thought you might be interested in some things granted by the Commission. We had a unique set of circumstances and an equally, I think, unique set of limitations on our operation during the scheduled extension period. This touches on some of the differences between HTGR and LWRs.

The circumstances we submitted as part of the November 1985 extension request, we had a higher temperature of harsh environment, were not able to use most of the industry qualification data that was forthcoming. Our SLRDIS system does enable us to use a great deal of that data for our new program, but the way the initial program was put together we were out there on our own with these 5-, 600 degree Fahrenheit peak temperatures that we were trying to qualify our equipment to.

1980 NRC order to us had a special phrase in it that we were to apply the environmental qualification guidelines to the extent applicable to a gas-cooled reactor. We proceeded to do so, and as Ken mentioned, it wasn't until early '85 that we got some feedback from the NRC Staff about the misapplication of the criteria in a couple of areas.

We've had a great deal of interaction which has helped the program along tremendously since January of '85. At the time of the schedule extension request and even at the present time, we didn't during the development of our program receive either a technical evaluation report or a safety evaluation report on the original program that I had up here, and that's one of the scheduling problems that we were out of time by the time the NRC took a good, hard look at us.

Lastly, the four-minute versus 10-minute operator response time, we felt we were on solid ground with the four minutes since NRC had reviewed and approved that in writing twice before, and then post-TMI era came out with their 10-minute criteria.

MR. SIESS: They gave you a six-months extension?

MR. HOLMES: Yes.

MR. SIESS: In view of the fact it took them between five and 10 years to change their minds, depending on whether you start in '75 or '80, I think maybe you discern a little larger extension. Is that all you asked for?

MR. HOLMES: That is what we originally -- we went and asked for an open-ended schedule extension and they wanted a date on it and we picked that one out of the air. We in the last month or so have been advised by the NRC that we may want to petition them for a supplemental schedule extension for the period after we finish our shutdown and all our plant modifications to put in the various environmentally qualified equipment while they are reviewing and giving us the approvals of our post-modification environmental qualifications, and we're proceeding to put that together.

MR. SIESS: That would seem fair.

MR. HOLMES: We hope so. We think so.

MR. WARD: If the NRC had responded more quickly after the 1980 order, what could or would PSC have done differently in that time? Were there some missed opportunities there?

MR. HOLMES: I'm not sure we would have ended up any place substantially different than where we're going at this particular time.

MR. BREY: We would have gotten there many years earlier.

MR. HOLMES: We're obviously getting there in a big hurry at the moment.

The continued operation of the plant during this schedule extension period kind of relies on a unique set of features of the plant. Basically, we agreed to a 35 percent power restriction during the scheduled extension period. This is the power level at which the reactor is on the verge of being inherently safe. Were we to have a high energy line break, say, at the 35 percent power level, as long as we got the liner cooling system going in about a day or so, 29.4 hours, the fuel temperatures would not reach the 2900 degree Fahrenheit failure level, and so the features of the current operational restrictions, again the 35 percent level, were we to have a high energy line break under current conditions, we've maximized our reliance on nonelectrical systems that we can use to mitigate the high energy line break.

The analyses that were done indicated that depressurization of the primary coolant system was not required, and in fact, the fuel temperatures ended up being less if you kept the vessel pressurized. That's not a choice for the 100 percent liner cooldown because of heat fluxes, but we showed that 35 percent heat fluxes from equlibrium to K heat, the liner could handle a nondepressurized cooldown. We also showed that actuation of reserved shutdown system would not be require.

Both of these we intend to do were we to get into a situation where liner system had to be relied upon if none of the forced cooling systems happened to work. There would not be any fuel particle coating failure. Temperature would get in the range of 2900 degrees Fahrenheit. A few may start failing but it would release fission products to the circulating -- activity would be less anyway. Would maintain the PCRV liner and concrete integrity. Again there could be some local concrete overheating or thermal barrier damage were we to go to this liner cooling mode, but the fission water barriers would be intact.

Again, there wouldn't be any significant impacts on public health and safety as a result of the harsh environment accident. The fission products would still be in the fuel particles which would be in the liner which would be in the concrete.

We do have a couple of licensing issues that are undergoing Staff review and consideration at the moment. Our steam line rupture at the detection and isolation system we feel does represent an unreviewed situation. There would be an increased probability of a 30-minute interruption of forced circulation cooling as analyzed in the FSAR, and the accident could involve a reduced margin of safety for continued forced circulation cooling.

The other issue that is under consideration or in the preparation of being submitted to them concerns the environmental qualification of our design basis accident equipment. I want to get into this area a little more thoroughly. 50.49 sort of presupposes that the worst case harsh environment accidents are your design basis accidents, which, in a water reactor, if you have a loss of coolant accident that obviously creates a harsh environment. In our case, our design basis accidents, one does create a harsh environment in one area of the plant, the other doesn't create any harsh environment. I'll get into that in a minute.

The other position of note here, the NRC has stated to us that during the harsh environment accidents, that none of the fission product barriers should be degraded during the course of an accident. It might be the onset condition for the accident but they shouldn't be degraded any further.

Our design basis accident number 1, which is the loss of forced circulation cooling again, I've described that already, basically the worst environmental impact would be a mild radiation level in the reactor building, not something that would prevent access, but assuming the fission products do permeate out through the seals in the concrete, there could be a mild radiological environment in the reactor building. Nothing that would approach any equipment qualification impact levels. It would be more of an operator access time restriction concern than anything to do with equipment qualification.

However, our DBA 1 accident equipment does experience a harsh environment during a high energy line break. On the other hand, if you don't rely upon it to respond to a high energy line break, and then that leads us into a situation that 50.49 really doesn't seem to be set up to handle. It presupposes that this equipment meets environmental qualification unless it is in an environment that needs to be qualified. The DBA 1 does result in degradation of a fuel particle coating barrier which is at odds with the guidance that the NRC has given us that that's not supposed to happen in an environmental qualification accident. This led us to the collusion that we need to environmentally qualify our forced circulation cooling systems.

We received a letter in February from the NRC that indicates to us that we should qualify our design basis accident number 1 equipment. After discussions with them, we're in the process of preparing and submitting an exemption request that basically, based on compounded low probability accident conditions, the high energy line break to begin with, and assuming both environmentally qualified forced circulation cooling systems won't work, would be compounding accident conditions and taking us further than they have taken other plants.

MR. SIESS: I'm confused. The DBA number 1 equipment is the equipment you need when you go into a loss of forced circulation?

MR. WARD: It is a liner cooling accident.

MR. HOLMES: The pumps are in the reactor building. There's an assortment of control valves that are electrically actuated. It does involve the use of the reactor building exhaust fans and filters.

MR. SIESS: What I'm confused about is that you said that your steam line detection and isolation system puts you in a DBA 1 situation.

MR. HOLMES: Right.

MR. SIESS: So if you have the high energy line break you put yourself in a DBA 1 position?

MR. HOLMES: Right. That's the first low probability accident.

MR. SIESS: Does DBA equipment have to be qualified for that?

MR. HOLMES: That's kind of the onset of DBA 1. You then have two redundant environmentally qualified systems to restore forced circulation cooling within 90 minutes, and if we were to qualify DBA 1 equipment, that presupposes that the two environmentally qualified systems don't work.

MR. SIESS: You have equipment, then, environmentally qualified to recover from the DBA 1?

MR. HOLMES: Right. The temporary DBA 1 that isolates the leak.

MR. SIESS: What they want is for you to qualify the equipment you would need to ride out a DBA 1?

MR. HOLMES: Right.

MR. SIESS: Okay, I see the distinction.

MR. HOLMES: It is our position that that's compounding low probability accident conditions. That's not to say that we probably couldn't bring some combination of equipment to bear to do a liner cooldown were we to not be able to fire our environmental qualification systems, but we don't want to be placed in a position of having to qualify another complete array of equipment.

MR. SIESS: You have 90 minutes to avoid a DBA 1. You have qualified equipment. If that equipment doesn't work you then are in a DBA 1 and that has consequences that you outlined earlier, 36 millirem to the thyroid and so forth.

MR. HOLMES: Right.

MR. HOLMES: Concerning our design basis accident number 2, I've already talked about this one. This is our design basis depressurization accident that assumes the simultaneous failure of two associated penetrations on the PCRV --

MR. SIESS: 2 in series.

MR. HOLMES: Yes, that would release the primary coolant inventory to the environment immediately. There's a specified percentage of fission product played out that would lift off and so on. This accident does create a harsh environment in the reactor building. You have your hot primary coolant in the reactor building. Most of it has departed the reactor building in seconds, and nominally the rest of it is cleaned up by the fans and filters. This, however, from an equipment qualification standpoint, is not the worst case harsh environment in the reactor building. The high energy line break creates higher temperature conditions, human identity, so on. The radiation dose from the DBA 2 is there and gone and accumulated doses are almost nonexistent from an equipment aging standpoint.

With respect to the turbine building, DBA 2 doesn't create a harsh environment at all. Most of the equipment we rely upon to deal with a DBA 2, the feedwater pump and train is in the turbine building. We did this past fall agree with the NRC to environmentally qualify our DBA 2 equipment in the reactor building that would see the harsh environment during the DBA 2, and at the time we thought that agreement would put the issue to bed.

Again, there's DBA 2 equipment in the turbine building that's going to experience a harsh environment during a high energy line break in the turbine building. At the moment, the NRC letter we received in February does say that we ought to environmentally qualify the DBA 2 equipment that does see a harsh environment. Some of this may be an interpretation on our part, but given the way the regulation reads, we're assuming that means the DBA 2 equipment in the turbine building, and we're going to ask for an exemption request that we not have to environmentally qualify the DBA 2 equipment in the turbine building since it will not experience a harsh environment during an accident that it is required to respond to.

MR. SIESS: These results from the accident sequences are nothing like the accident sequences in the water reactor?

MR. HOLMES: That's fundamentally the case. They stuck those words in 50.49.

MR. SIESS: In calculating the activities released when you have a DBA 2, using some assumption regarding liftoff, and I assume you are still using what was in the

FSAR. As I recall that was based on not an awful lot of experience at the time and it was quite conservative. Has there been any improved basis in our knowledge of how much played out there is and what the liftoff might be?

MR. WAREMBOURG: There has been experiments on that.

MR. HOLMES: There has been some French work recently that there's differences of conditions and so forth that would -- it has led GA to request more dollars from DOE to do more analyses and more tests and try to get more data. There still is not a great deal of data on liftoff.

MR. SIESS: It is my recollection that most of the curies that get out are from liftoff. Most of the iodine is. Something like 18 and 20 curies of iodine in the helium and you end up with a lot more than that in a liftoff. The net result is so small there hasn't been much of an incentive to --

MR. HOLMES: From a radiological standpoint --

MR. WAREMBOURG: Also the iodine played-out probes -- we've taken some out and iodine played-out probes indicate we have substantially less played out.

MR. HOLMES: The liftoff percentage, there's not a lot of verified data.

MR. SIESS: What percentage did you presume was lifted off?

MR. YOUNG: The data was something like one, one and a half percent liftoff. The NRC made a more conservative assumption. The staff assumed something like 5 or 6 percent and then based on that assumption, set the technical specification limits on iodine played out in the PCRV in a lower value than that contained in the FSAR, so there was sort of a tradeoff both directions made when they did the evaluation.

MR. HOLMES: DBA 2 does involve a significant amount of either whole body or thyroid release, much more so than DBA 1.

MR. SIESS: But it is less than the 10 percent that's used in other accident analyses? The water reactors has a criteria of something significantly less than .100. That's 10 percent.

MR. WARD: For a steam generator to rupture.

MR. HOLMES: We're talking about two independent passive failures in order to get this accident. We recently submitted a calculation to Staff that indicated this is like a 10 to the minus 9th sort of condition, not 10 to the 2.

MR. SIESS: I read that. It is sort of simplistic but I wasn't quite -- I'm pretty well convinced it is less probable in a steam generator tube than in a water reactor. I just wanted to get some feel for it. There hasn't been much incentive to reduce those calculated figures.

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MR. WAREMBOURG: Don Warembourg. The other concern we had once you draw in DBA 1 and 2 under 50.49, it also requires as a standard analysis that you take, coincident with the high energy line break, a loss of outside power. If we've got to combine DBA 1 and 2 with a loss of outside power we cannot survive those incidents, even if we qualify the equipment we cannot survive because the diesel generators will not pick up our water feed pumps. It is a situation we're dead either way unless we get relief from that.

MR. SIESS: When you get into that we're up in the severe dose category rather than what we usually think of design basis accidents.

MR. WAREMBOURG: But that's the interpretation of 50.49 and that's where we are. We're up against the wall with that one.

MR. SIESS: I'm not sure that your design basis accidents have a one-to-one relationship to the DBAs for the water reactors in terms of probabilities. I'm not sure because we haven't got a real PRA that I've looked at on this.

MR. HOLMES: We're now up to the scheduled lunch break.

MR. SIESS: I propose we continue until 12:30 or closely thereto.

MR. HOLMES: This concerns our technical specification upgrade program. I wanted to review some of the ground rules that were set forth at the outset of the program and then secondly indicate how we're taking standard technical specifications into account, and give you a bit of an indication as to what the schedule for the program is.

Immediately subsequent to the June '84 problems that we had with the control rod drives, the NRC did dispatch an audit team out, looked this over, and one of their five areas of concern dealt with our technical specifications and the difficulties that are inherent in understanding what the technical specification requirements are under certain specific circumstances.

After a series of discussions with them, PSC did agree that we would upgrade our technical specifications to be more consistent with the modern present day understanding of how to put together a proper set of technical specifications. In order not to redo the licensing basis of the plant, we did talk about and establish some basic ground rules for the program to try to make the upgrading of technical specifications consistent with the licensing basis for the plant, rather than undergo a major change to that licensing basis. The scope of the program, we did agree that our LCO's would be freshened up, to specify on an item by item basis the sorts of things that the standard technical specifications do mention in the applicable operating modes to each. Specify limiting conditions and specify action statements to be taken if those limiting conditions are not being met at any point in time.

MR. SIESS: You don't mean they don't do that now?

MR. HOLMES: In some instances it is difficult to figure out exactly what the action is supposed to be. Sometimes the applicability is unclear, what if this is done at a lower power level or shutdown, or when this does happen what do we do about it?

MR. SIESS: Have you got LCOs that don't agree with the FSAR? I thought the FSAR was the basis for setting the LCOs.

MR. HOLMES: There have been instances going through the FSAR it is not too clear as to how the tech spec relates back to the FSAR, or in other instances we'll find something in the Fort St. Vrain that's not covered by a tech spec that should be; so we're dealing with those sorts of situations too, trying to get a one to one relationship between the FSAR and the tech specs. This ground rule kind of changed after we got going.

Originally we were going to cross-reference between the LCO and the FSARs. We finally adopted the standard tech spec format where the two are next to each other and it is clearer how the requirements relate to the LCO divisions. Then surveillance requirements to verify compliance with the limiting conditions for operation. The next might be a pie in the sky, that we're trying to make unambiguous statements with a singular interpretation. I don't know if that's possible but that's one of our objectives.

MR. WARD: What do you mean by that?

MR. HOLMES: Define the terminology being used in the specifications, the next slide indicates we're trying to use standard tech spec definitions where they fit in. Keep them, and simplify the tech specifications if and where possible, and try to make sure they are accurate, complete and consistent with the existing design and safety analysis documentation. In trying to put this program together, we have found, going through all the operating modes, power, low power, shut down, refueling, start-up, so forth, we have found a number of instances where under some given power level or set of circumstances there was a hole in the tech specs that they just didn't address the situation, particularly over onto the 2 percent power range. So we're trying to plug the holes.

MR. SIESS: The people writing codes and specifications, there's a computer program that's been developed that checks for completeness, uniqueness, et cetera, and it finds the holes, the gaps that are left out. As far as I know, it has only been applied to one code. That was the seismic code that was developed out on the West Coast with ATC. I tried for years to get it applied to the ACI building code and have not been successful. You have to start off with decision tables that actually will check, it will pick up with decision tables as a tool; it will pick up something that fell through the cracks just like that. You say simplify if possible. What are you doing in any way related to the tech spec improvement program the Staff is looking at?

MR. HOLMES: This program was already under way for like nine months when the reports of some of these tech spec improvement efforts by AIF and NRC came out in the fall of '85. We are trying to consider and take into account some of their recommendations. Unfortunately, those reports are kind of leading NRC rulings and policies regarding tech specs. They have not implemented the reports to any great degree so far and we're discussing --

MR. SIESS: But there was a direction indicated of maybe trying to take some things out of tech specs, licensing conditions and those kinds of things.

MR. HOLMES: We're looking at those areas. One of the big recommendations was to beef up the bases for the tech specs. Relative to standard tech specs our existing tech specs have a much more substantial bases than the standard tech specs and our upgraded tech specs are another enhancement on that effort. Obviously, being the one different reactor and trying to explain why the tech specs are the way they are, it just takes more words, so we can acquaint the future NRC inspector that hasn't been involved with us to come in and understand what the speculation means, we do have a lot of words and bases.

MR. HEITNER: One thing, we, the staff working on this have tried to keep up with all the initiatives that are being done in-house by the NRC to revise, enhance and improve the whole tech spec process. We've also kept aware of unique options that have been pursued by other licensees such as Perry's attempt to remove fire protection tech specs and put it in a separate document, and the attempt to revise the diesel generator tech specs to reflect the actual performance, so the tech specs are flexible. The testing is based on how well the diesels are actually doing. We try to incorporate all of the innovations that have come along in the last year or so as best possible.

There also are certain areas in the technical specifications that we probably won't be able to finalize in the upgraded program, such as the tech specs for the control rod drives and the associated instrumentation, because PSC still has ongoing studies and work that we're doing concerning the eventual instrumentation that's to be used for the control rod drives and requalification of control rod drive mechanisms to higher temperatures. All would eventually affect the tech specs. Until that experimental work is completed we'll not be able to finalize those portions of the specification.

MR. SIESS: That last is not unusual. Every time somebody makes a change in the plant, the tech specs have to be changed.

MR. WARD: One of the aims of the NRR AIF program was to clearly separate and try to clearly separate tech specs, which are controls on operations from tech specs, which are controls on design or other aspects of systems or equipment that don't have anything to do with day-to-day operations in the control room. Does your program look at that sort of separation or do you find that sort of separation useful?

MR. HOLMES: We really haven't looked real hard at that particular criteria. PSC of course is trying to keep the tech specs a reasonable size, and we haven't -- a lot of the specs that would fall into that area are already in our tech specs, have been for years. Of course we're used to them and it doesn't bother us that they are there. At this point, we really haven't tried to sort out the design features from the operational tech specs. That's always a possibility.

In respect to the use of the standard tech specs, we initially started the program using the Westinghouse as a guide. That subsequently was revised to use the Westinghouse review tech specs. The ground rules for taking tech specs into consideration were, number 1, we would not undertake plant backfitting for the purpose of adopting some standard tech specs requirement. It was also agreed that it would be outside the scope of the upgrade program to consider licensing issues that may be raised by again looking at standard technical specification requirements for guidelines. If something was to present itself in the way of a licensing issue, that would be treated separately from the upgraded program to avoid getting it bogged down in any number of licensing issues. It was also a ground rule that we would not undertake anything substantial in the way of R&D or analytical investigations to determine how it would be appropriate to utilize STS requirements. This is a changed ground rule from originally. We did, in the first draft submitted in April of '85, within the last week before that submittal, actually decided to adopt the standard tech spec format that existed. The plant operators initially didn't want to go along with that. By the time they're viewed any number of surveillance requirements of LCOs which we presented in the same package to them, juxtaposed on one another, they finally saw the light of making them both understandable and did adopt the standard tech spec format numbering system. Relevant STS definitions are being adopted as I mentioned before. There was maybe a handful of definitions that were relevant and usable.

Again we are, all other things being equal, we're adopting the standard technical specification requirements where it doesn't impose any undue hardship or conflict with the design basis of the plant. There's an initial ground rule that we would not have to submit an extensive justification or analysis on how we were dispositioning standard technical specification requirements. It is fairly apparent we can use them, they are relevant or they are more water reactor-oriented and you do business a different way.

The schedule that we're on initially was kind of a fast-track schedule. It slowed down in recent times. Again, from the initial audit in July of '84 we had a number of discussions and we finalized the scope of the program in November of '84 and submitted an initial schedule for the program in December of '84 which called for the submittal of an initial draft of the upgraded tech specs in April of '85. And we did in fact submit them on April 1 of '85. After an NRC review period and exchanging, receiving written comments from them and getting everybody's thoughts together, we met during the week of July 20, 1985, and went over the entire draft, established areas of agreement, the areas where further actions had to be taken by both the NRC and us, and we both then went off to undertake to answer those questions, resolve the action items. That all led to what's referred to as the final draft, in November of '85. The schedule from here on out -- the NRC, I believe, has pretty much completed the first round of their review of the final draft and will be sending comments back to us in the near future.

At that point, now, the schedule nominally calls for us to receive those comments, and it was based on comments not being particularly extensive or earthshaking, if in fact that's the case, we'll go ahead, resolve them, incorporate them, put the packages together, submit it through our Plant Operation Review Commission and Nuclear Regulatory Safety Committee and submit them for NRC approval 90 days after receipt of their comments. Then NRC would approve the upgraded technical specifications six months prior to start of fourth refueling. Given the plant operating experience, refueling dates are slipping, and we have had some verbal interaction with the Staff that indicates that comments may be a little more extensive than we would hope at this point in the program, but we have yet to see those.

MR. SIESS: Who in NRR reviews tech specs?

MR. HEITNER: I was originally doing this in the tech spec review group, in the reorganization that has gone away, and now it is being handled in some of the operations branch division of PRB licensing-B.

MR. SIESS: One branch that has that responsibility?

MR. HEITNER: They have the lead responsibility. They are coordinating the review with all of the technical branches reactor systems, mechanical engineering, systems control branch. Everybody is essentially involved.

MR. SIESS: That's why it takes so long. Let me ask, just out of curiosity, you mention surveillance requirements and the LCOs that go along with them. Do you have that on a computer?

MR. HOLMES: To actually implement them?

MR. SIESS: No, something that you could pull up every day and say what surveillance requirements are to do that week or next week and what LCO is going along with them, so you don't miss one?

MR. GAHM: The LCOs are checked by computer printouts. The surveillance reports are.

MR. SIESS: You can schedule them and --

MR. WARD: Is that an interactive program or just a report telling you what's due on a given date?

MR. GAHM: Basically a scheduling report.

MR. HOLMES: The next topic on the agenda, John

McKinley asked us to address the topic, and outside of individual issues it is a little difficult to talk about. On the subject of LWR versus HTGR characteristics, there's one very significant thing that's happened during the past year. PSC has received very clear direction from NRC Staff and is now of the understanding that, number one, we're to comply with the NRC's regulations, and including the guidance and the policies that they utilize in implementing those regulations, unless we submit to them and receive an official exemption to those regulations.

MR. SIESS: You mean there's a requirement to have a water level gauge? You either put one in or ask for an exemption?

MR. HOLMES: Yes. Depending on how that's written up, it says PSC do something, we may back off of that, but we have to be careful backing off of that.

MR. SIESS: I think the Staff, I've noticed, in some areas has gotten more careful about referring to lining water reactors. I know a number of regulatory guides got their title changed to mention lining water reactors.

MR. HOLMES: That's certainly helpful in our case.

MR. SIESS: Do you assume in writing the exemption request that it is obvious or do you have to write four or five pages? Are some of them obvious enough that you can say, that obviously doesn't apply?

MR. HOLMES: We have not taken that approach. At least normally, like on the fire protection business with the hydraulic oil cooling system, we did submit, I think it was like three or four pages saying we didn't have reactor coolant pumps, we have helium circulation pumps. We don't have an oil collection system. We hunted around and didn't find anything that came close.

MR. SIESS: The intent of it was --

MR. HOLMES: Relative to the impact on the primary coolant system, yes, we looked. We have lube oil out for the generator turbine system, but that seemed far afield from the intent of the regulation.

MR. WARD: Does this represent a change in the sort of de facto policy? Are they passing the ball to you and expecting you to take the initiative in correcting things? Is that the difference?

MR. HOLMES: In the past we've had an informal relationship with the NRC where if something came out, we might get the project manager on the phone and say, hey, this came out, what do you think, what should Fort St. Vrain do about it? And quite frankly, the answer in the past came back that, hey, that obviously doesn't apply to you. It was done over the phone and nothing was ever documented and years later somebody would come along and say, I'm here to audit you as to your compliance with QYS; and there is nothing in writing, and it is a bad deal.

MR. SIESS: You are in a better position to decide what applies obviously than the Staff is; is that right?

MR. HOLMES: We certainly intend to participate in the process.

MR. WARD: It is going to take resources on their part.

MR. HOLMES: For years, of course, we have been in the gas-cooled reactor and water reactor industry and have had to analyze and reach determinations on regulations. In the past it has been done more informally than it should have been and --

MR. SIESS: I think some of your problems now are things that developed five or 10 years later would have been more easy if things had been documented five or 10 years earlier.

MR. WARD: You think there ought to be a clear responsibility one place or the other?

MR. HOLMES: It has its advantages and its disadvantages. I think it will require more technical licensing Staff time in order to get these things straightened out for a gas-cooled reactor. On the other hand, taking the time up front may avoid difficulties in spending the time later on down the line.

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MR. SIESS: On the other hand, I think it would have been appropriate for the director of NRR or whoever to indicate to the Staff that they should be more careful in their regulations in making distinctions between light water cooled reactors and high temperature gas-cooled reactors.

MR. HOLMES: This reflects some high level NRC management discussions with us.

MR. SIESS: You're not going to give us a lecture on the differences?

MR. HOLMES: I really hadn't planned on it.

MR. SIESS: I think we're fairly well aware of them from previous meetings.

MR. WALKER: Does that cover your concerns, John?

MR. MC KINLEY: Yes.

MR. SIESS: That brings you to the end of your presentation. We've gained some time and I will declare a noon recess. Well, I'll say until 1:00.

(Whereupon, at 12:20 p.m., the meeting was recessed, to be reconvened at 1:00 p.m., this same day.)

AFTERNOON SESSION (1:00 p.m.)

MR. SIESS: We'll reconvene. According to my agenda we're down to item B under 5.

MR. WALKER: What I would like to do is give you some background in some of the areas that are not technical but I'm sure they are of interest to the Subcommittee and some of the NRC people.

The first one, let me talk about our regulatory environment and the status of the different issues with the Public Utilities Commission. Before I do that, let me, for some of you that have not followed our concept or our plant from the beginning, let me go back in history and set this in proper perspective.

We did get our construction permit and our certificate from the Commission back in 1968 and, as you know, we had a contract with the General Atomic Company to construct this plant on a turnkey basis. The contract provisions called for the plant to be in service in April of 1972. Recognizing that there could be the possibility of delay since this was the first of a kind plant, as part of the process, and I won't go into the details, we did set up a provision to protect our company in case the plant was late, and of course the plant was late, and it in fact did not come on -- go commercial until 1979.

The provisions of the contract provided that as far as the company was concerned, we had coming to us damages from the vendor for the delay of Fort St. Vrain, and the way we calculated those was to do a pro forma on what the cost would have been had Fort St. Vrain been running starting in April at 380 megawatts and 80 percent load factor.

Then we compared that with the actual costs we had in the company and then that differential was billed to the General Atomic Company and credited against the operating expense of the company. Over that approximately seven-year period these credits amounted to about $75 million, so our customers got the benefit, at this time, of most of this in the fact that our O&M expenses were reimbursed and there were a reduction in expenses and of course they were paying nothing because there was no investment to pay on.

As far as the customers were concerned, they did get some benefit from the plant for almost a seven-year period. Sometimes we forget that.

We did accept the plant in 1979 as most of you know, and of course the plant did not meet the specifications in the contract, and so we had another decision point to make, whether to take the plant as is or refuse to take it and go to court or to work out a settlement with the vendor. We did choose to work out a settlement with the vendor which provided $60 million up front, $7.5 million over a number of years plus nine segments of fuel plus other equipment. On that basis we took the plant, recognizing that we took it at a reduced rating of some 200 megawatts and 60 percent load factors. I think most of you knew this, but I wanted to be sure. We've had some protection for customers and shareholders over the years.

; even though this has been a long drawn out process we have been fairly fortunate in having those contractual arrangements. Without those, we would have been in deep trouble.

As far as our dealings with the PSC, this is a frequent event with us. There are four actions and I'm not going to go into the details, the first goes back, Fort St. Vrain was put in the rate case November of 1980, as I recall, along with going into the rate case, was to meet a capacity factor test. Those two cases, arising out of that case has been a court action and that's in the Supreme Court of the State of Colorado. The capacity factor test that was put in that rate case, the period of time we went through that, we concluded we had met the capacity factor test. The Staff of the Commission concluded that and so did the Commission itself. Intervenors claimed that it did not meet the test and that's gone to the District Court and that's also residing in the Supreme Court.

There's another case that has to do with what's called an incentive plan, and if the Fort St. Vrain doesn't run, then the amount of money we have in our rates should be reduced and refunded to the customers. I won't go into the details of that, but that took effect in November of '84. We have appealed that through the court system, and that is also in the Supreme Court. That's three cases in the Supreme Court.

There's another case just going. Prior to the time of the incentive formula there was a mechanism in our energy adjustment clause to account for Fort St. Vrain not running and there was some dispute on the aspects of that, and that now is about ready to go to the Supreme Court, so there are four cases in the Colorado Supreme Court. I will not make any projections on when those might be heard, let alone settled, so that's the status of that. If you want more information I'll be glad to give you a copy that explains it in more detail.

The other action is the Office of Consumer Counsel which in our state is an ombudsman for the customers. It is a separate agency from the PSC. They have filed a complaint about whether Fort St. Vrain should be in rate base or should ever have been in the rate base. That's at the Commission level. That's set for hearing October 22, 23 and 24, dates to that effect. So we're actively pursuing that.

That's a brief rundown of the other side of the business, the one I worry more about than my managers here, and we'll just have to let the court actions take whatever they come out. We'll have to live with the results of those. In two of the cases, our accountants or auditors have had accrual of the funds against the income, so we've already taken a hit against net income and of course the money has not been paid, it has been accrued. If we win, we will get the money back to net income; if we lose, we've already credited it. I won't go into more detail on that.

The next item has to do with continuing technical support from GA and of course I have many friends in General Atomic and we've worked closely with them. Some of us are getting greyer and older but still have that zeal for the concept and they have been good to work for and they are the only one that really has built gas-cooled reactors and we rely heavily on them. Of course they are our fuel supplier. I think most of you know the scenario where Chevron purchased Gulf and they do own GA Technologies. It has been in the public press that GA Technologies is up for sale and the potential buyers is an organization called the "Blue Hill."

"Blue" stands for a family that originated in Denver and still some live here, who I know, and have worked with in the past, and they are the potential buyers for GA Technologies. They are entrepreneurs, technical background, exciting people to work with. I've met with them recently and I detect a little zeal and enthusiasm on their part for making something out of this concept and they are a new, fresh face. We will be involved with a company like that. The "Hills" part of it has to do with a Canadian organization. We're looking forward to working with them and their continuing in business for us. The next item is HTGR development support. You've had a presentation, haven't you, on the modular HTGR?

MR. SIESS: Yes.

MR. WALKER: I won't go through that. We have a dog and pony show we could go through, but I think you're familiar with that. I would like, for the benefit of the record, to indicate that some of us feel strongly about the gascooled concept. In spite of the decline in interest in ordering nuclear plants since '73, we felt it was necessary to keep this concept alive, so in '77 and '78 we and formed a group called Gas Cooled Reactor Society, of which I'm the chairman and these are the good old supporters, Philadelphia Electric, TVA; we have some 30 companies affiliated with us in one way or the other. We felt with the decline in orders that occurred in the '77, '78 -- and there were going to be no gas cooled built and no more water reactors built -- we needed to keep the technology going, so we formed this company. We are funded now at about a level of $4 million and we work closely with the Department of Energy, with EPRI and with the vendors to keep the concept alive.

From '78 through '84 we worked on a standard 855-megawatt electric gas-cooled plant which, we spent between ourselves and the Department of Energy, how much money, Dan?

MR. WAREMBOURG: Probably $50 million on the design.

MR. WALKER: We have a good complete design on that size of reactor. Since part of our funding comes from the Department of Energy, we have to be sensitive to what's doable with government funds. It appeared to us, as we finished up that design, that there were no markets available for that large-size plant because of the financial risk in the length of time it just imposes you to go into a large project, so we switched gears in '84, and began to relook things over with encouragement from people that maybe we needed to rethink the whole concept and big isn't necessarily better or cheaper. Sometimes economies of scale help and sometimes they don't.

We've spent some of our money and quite a bit of DOE money coming up with a module of gas-cooled design. It would be a side-by-side vessel and it has the inherent characteristics of being smaller than our reactor, the St. Vrain one has lots of time to do things you have heard today. You get to this core with the lower power density, its arrangement and its size, and you have a basically inherently safe device. You have to have control rods, but you can imagine scaling ours down, decreasing the power density, and the cooling requirements are very minimal. It is our hope that this could be carried forward.

Our plan calls for trying to set up a vendor supply company and a utility user company, which we would incorporate and would attempt to, with the help of DOE, come up with one full-sized demonstration module with 140-megawatt electric -- the Idaho Falls INL site would be a good place for it. It doesn't have to go there. What we would like to show is that this could be replicated and absolutely demonstrate its safety and the number of safety systems you need on that is a fraction of what you need on any other reactor. We would hope to consider these modules as loops. This would get you 560-megawatt electric, and we thing the advantages of doing that -- and maybe someday we could get down so this design could be certified and you could buy them like you buy 747s or DC-10s or anything like that. It may be a pipe dream and way beyond my tenure in this kind of work, but it is something that ought to be looked at. The other advantage I see is the days of spending 2, 3, 4 billion on something you don't know whether you can earn on it or when you can operate it are gone, as far as I'm concerned; and also the load growth, we are not experiencing 7, 8, 9 percent load growth. Most of us are down to 2 percent load growths so the modular concept fits in nicely. You could put in one module, two modules; you could put them in on a short-time schedule and if a lot less fraction of that plant had to be nuclear-graded, you could get less paperwork on it and I've seen studies that show building the same system, one completely nuclear safety grade and the other standard, just the paperwork amounts to factors of three to one or something like that in cost of building the plant. We're encouraged that this is something that could be done.

The next item, of course, has to do with our support from the federal government, the Department of Energy, and when we first started this route after ACRS was formed, we had difficulty getting money. We were generally not even in the DOE budget. We would have to go to our friends in Congress, Senate Energy Committee and the Appropriations Committee, and get money put in to keep the concept going. We were successful in doing that.

A couple of years, DOE recognized that and began to put money in to keep the basic program going and then came Gramm-Rudman, which even you fellows in the NRC, I think, are experiencing a little bit of Gramm-Rudman, which has obviously affected all of us and we're taking a small cut in this year's budget, and we're in the budget for 19 -- fiscal '87 at only about \$5 million versus some \$28 million for 1986.

I have been testifying. I'm going to testify some more. We're certainly going to try to get that raised, because we thing this concept needs to stay on the books and keep going, because it may be the only way we can have a nuclear industry is to get down to something like this that can be done simply and not have -- everything has just gotten too complicated and takes too long to do. Also, we are probably the only viable utility group that still really is working as a group to promote advanced nuclear concepts.

That doesn't mean there are not other concepts that have their supporters, but they don't have an organized group doing it like we do. We do have a good group. A little encouragement, the Department of Energy has an energy research advisory board called the ERAB. They have an ad hoc panel on nuclear power which I'm on, and we're about to come up with our recommendations on what DOE should do in the nuclear -- and of course, the report has not been released and approved, so I can't tell you exactly how it will come out, but there's a section on advanced reactors and there's emphasis on the modular reactors, both liquid metal and high temperature gas-cooled, and we recognize coming out with a recommendation at the time of the Gramm-Rudman budget doesn't make a lot of sense, because they probably can't do some of this, but it is our feeling that we should say what we think ought to be done. If there isn't funding, that should not be part of our consideration. I'm encouraged there of that consensus.

We're also getting some help help from the Electric Power Research Institute. Their nuclear budget is not all that big and they have to represent people with light water reactors which are very important and need continued funding. We're encouraged and we hope down the road someday we can start building these modular HGTRs and get on with the business. That's a real brief update.

MR. SIESS: You may not be the person to answer, but is there any industry group interested in an LMR?

MR. WALKER: The only one that has some left, you remember the Breeder Reactor Corporation involved in Clinch River which was -- of course with the demise of Clinch River that project came apart. We did keep the Breeder Reactor Corporation. I happen to be a director of it which is a utility organization as a shell. We have changed the name to Advanced Reactor Corporation, so if someday there's enough interest, we'll have a shell corporation. We don't meet or spend money but there's no organization. There's some vendors, Rockwell, GE, Westinghouse that have interest in the liquid metals --

MR. SIESS: Interest in building one or just doing research for DOE on it?

MR. WALKER: There's no utility group out there that's organized.

MR. SIESS: The vendors. I know .ey are perfectly willing to do the studies for DOE. Are any of them really interested in putting one together?

MR. WALKER: I don't see a lot of them that are willing to spend a lot of their own money on this. I appreciate their position. No orders since 1973 and living off service contracts and I don't think you can expect them to put up tons of money to do this. We're working with several of them to try to form a supply company in which we could get some help, and I think there's a possibility of doing some of that.

MR. SIESS: What's the situation for fuel at Fort St. Vrain?

MR. WALKER: You remember our deal with General Atomic Company, there was a contract for fuel and one for building the plant, and of course the only fuel manufacturing is in Sorreno valley and of course that's with part of Gulf and the new company, and we have a contract to provide -- we have the first nine segments free, six in the reactor and three that were built. Segment 10 and on we're buying at cost, and we have purchased segment 10, which would go in the reactor probably in early '88.

MR. SIESS: A segment is a reload?

MR. WALKER: Yes. Our contract provides .t runs

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into the '90s for them to make fuel. There is a provision in the contract that if they go out of business for any reason we would have the right to purchase the technology and to continue with that so that would go into the '90s. We don't have an absolute fuel supply to the year 2008, but they are covering costs and are keeping the facility going and, of course, it is my hope that the modular reactor will catch on and it would use this prismatic fuel --

MR. SIESS: On the back end isn't there a 1990 or so limit on your agreement with --

MR. WALKER: What we did on the spent fuel, we made an arrangement with the Department of Energy where they actually take ownership of the fuel. When the plant was originally conceived, the fuel would be reprocessed and uranium 233 would have been a valuable product, but as you know, there is no reprocessing, so our case looked -- rather than try to keep ownership of the fuel, and hope that someday you could reprocess that and get your value looked like a long shot, so we worked out a deal for eight segments where we give it to the government and they take ownership and if it can ever be reprocessed, the government will get the value out of it. Long-term-wise we're like everybody else, we'll have to rely on some permanent long-range storage when we get to the '90s. We're all paying into that fund, you know.

MR. SIESS: You pay into it too?

MR. WALKER: Yeah, we didn't, but we are now.

MR. BREY: As long as we generate, yes.

MR. WALKER: That's a very brief one. I thought it would be of interest to you.

MR. SIESS: Down to item 6, which is a series of presentations on technical issues, we'll go on with those until we find an appropriate quitting time. Mr. Walker says everybody is here. We can go past the scheduled order date; is that right?

MR. WAREMBOURG: Yes.

MR. SIESS: Is there any objection if we went a little past 5:00 o'clock?

MR. WAREMBOURG: I'm Don Warembourg, manager of nuclear engineering. I'm here to kick off the technical issue of the program. Most certainly since you were here last time, we have not expressed any great want for the lack of technical problems. We've certainly had our share since you were here last time. The first subject we want to discuss is on moisture ingress, and you may recall when you were here last time we did have in place at that time what we called a Moisture Ingress Committee. I was the chairman of that committee at that time.

We had several Public Service Company representatives and in addition to that we had several consultants on that committee. That committee was really charged with going back and reviewing all of the helium circulator events, the transients, those things which resulted in moisture ingress to the core and then trying to come up with solutions or modifications or things that could be done, reasonably done to the plant to try to at least mitigate the moisture ingress, the consequences of moisture ingress and the number of events that might occur. When you were here last time, the Moisture Ingress Committee, of course, had defined several areas of activities and improvements that it wanted to accomplish and those, a good many of those have been. And I'll get into those as we get into the presentation, but the Moisture Ingress Committee continued to work and function until about October 23 of 1984, and at that point in time, Mr. Walker formed what was and is now known as our Fort St. Vrain improvement committee.

The purpose of that committee was to gather up a little bit broader scope and it was to formulate and review proposed technical improvements to enhance the operation of Fort St. Vrain, with the objective of financial or regulatory aspects of possible improvements should not be the primary consideration, and outside expertise was to be utilized as necessary to support that committee. The committee consisted of Mr. Walker, the chairman, Larry Brey, Jack Gahm, Leroy Singleton and myself, and with the formation of that

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committee we really picked up the activities of the Moisture Ingress Committee and the old Moisture Ingress Committee was dissolved with the formation of the improvement committee.

In terms of the various activities that we have accomplished and considered, both in the Moisture Ingress Committee and in the improvement committee, I'll give you an overall flavor. Underneath the old auspices of the ingress committee there were several things that were done, accomplished, and some things that were rejected and considered by that committee. First of all, we looked at the accumulated firings and recognized that within the control room the operator did not have an indication in the control room that an accumulator had been fired. If you recall, in the helium circulator system, in order to avoid damage during a transient we have a normal and a backup bearing water supply and, should either of those fail, we have a gas-filled cylinder with water that fires so that the circulator has enough water in the bearing water cartridge to coast down to prevent from wiping the bearings.

When you finally get to that accumulator firing it is not a very controlled process, so what usually happens when we get to that last-ditch operation and fire that accumulator, you generally send moisture up the shaft because the bearing water cartridge cannot handle that sudden influx of moisture. This was really an idea that was put in for an after the fact type operation, so the operator didn't have to go out in the field. So that was installed.

We also found that, in reviewing some of the transients, we found that when a circulator did trip and back up, bearing water came in. Oftentimes the operator, in trying to return the circulator back to normal operation, neglected to close the backup bearing water valves while bringing the other bearing water valves into service. That tended to flood the cartridge and send moisture up the shaft. In order to avoid that we've interlocked the backup bearing water valves with the main water bearing valves. As you start bringing in the normal bearing water the backup bearing water backs up and vice versa. We no longer have the possibility of an operator trying to bring in both systems at the same time.

We did look at the accumulated firing program. We went back and reviewed some of the early records at Belmont and determined that after several attempts there, we did finally get that circulator to run at Belmont and sustain accumulator firings without moisture going up the shaft. So we went back to that early program, tried to determine what kinds of calibrations and stuff we had on that accumulator at that point in time, then came back with our results people and recalibrated our accumulated firing programs here at Fort St. Vrain. We've not had any direct firing of the accumulator since we did that, so I can't tell whether we've been successful, but hopefully it would not send moisture up the shaft tip in time, but we have no indication whether it will or will not.

MR. WARD: You said found to be satisfactory? What does that mean, on the chart?

MR. WAREMBOURG: We calibrated it in terms of the program at Belmont and calibrated in terms of firing that program. We didn't actually smoke-test it to see if we got water up the shaft, but it is consistent with the test program we had at Belmont.

The system 21 instrument calibration frequency, we looked at that and found that in some transients, instruments didn't perform properly, didn't react properly and we at least determined that in some cases it was because the calibration frequency was not being done often enough to keep those in the calibration ranges they needed to be in.

MR. WARD: What is system 21?

MR. WAREMBOURG: The bearing water auxiliary support system for the circulators which includes buffered helium bearing water. So we did a complete review of the system 21 instrument calibrations and established new calibration frequencies for that instrumentation. One of the main problems that came out of the Moisture Ingress Committee that we determined was, at least the major contributor to moisture up the shaft was the drain system from the high pressure separator in combination with the main drain of the circulator.

As we investigated that, we determined that the drain line from the high pressure separator had only been sized within the plant to handle 5 gallons per minute. When we went back to the Belmont test facility, we found that the line there was sized to handle 15 gallons per minute. We began to look at that and decided that for some reason, in the transition from Belmont to Fort St. Vrain, we didn't bring the technology back with us and undersized that high pressure drain line. The separator tends to flood, and sends water back up the line and sends water up the shaft of the circulator. We modified that line and put it into a 20 gallon per minute flow rate. The drain line from the high pressure separator was also coming into the bottom of our bearing water surge tank. It tended to push water up the shaft and again flooded the circulators.

I might just give you a quick indication of what that system looks like so you'll have an appreciation for what's happening there. This is the buffer supply going into the upper end of the helium circulator itself. This is the helium loop seal or the drain seal that I'm talking about here. That comes into the gas side of the high pressure separator. The high pressure separator in turn drains and comes down and into the bottom of the bearing water surge tank. The bearing water gets rid of this loop seal and brings this drain line, instead of into the water side of the tank, brings it up on the gas side of the tank. We accomplished both those modifications under the auspices of the Moisture Ingress Committee.

Another area that we tried to clean up was the drain from the high pressure separator fed into the main drain valve off the circulator, and this is a valve which is really controlling getting water away from the circulator. As the system was set up, we're feeding forward a signal from the level in the high pressure separator to the main drain valve and we're also taking and trying to control that main drain valve off the differential pressure across from the helium circulator and as a result of that the control system did not always function properly. What we've done is separated those controls and relieved the level control separately, independent and let it drain by itself. We control the main drain valve directly that way; in the event of a transient we can get that valve open immediately and get that water to drain down the shaft and give it a path to go rather than up the shaft of the circulator. That was also accomplished under the auspices of the Moisture Ingress Committee.

We established a Transient Review Committee and the purpose of that was to investigate all serious plant transients in the plant with the objective of trying to get to the bottom of what caused the transient and then come forth with plant modifications which might eliminate transients in the future. That committee was formed and is active now. We also recognized that in support of this committee, we found that in system 21 there were many pieces of instrumentation, valve positions and so forth, which were not on our data logger in the control room. After the fact in trying to analyze a transient, we could not determine what happened during the transient, so we developed a computerized data system and now have that in place and that system then is a fast track system which will allow us to reconstruct the events in system 21 and try to determine what happened to us on that basis.

The other problem that we have was on the main drain valve in that it was a pneumatic valve, three inch valve, it was sluggish in opening, and as a result of that it tended to flood the cartridge. So what we did is, on an interim basis, we put valve opening boosters on those valves to get those open faster and get the water out. That helped considerably, but it still resulted in a situation that because we had those valve positioners trying to get that valve open fast, just during routine operation, the valves tended to hunt back and forth, that that did not allow any good control of routine operations, but it did on an interim measure help us. We installed new strainers upstream of the BUBW filters. We installed new positioners on the high pressure separator drain valves, replaced pressure differential instrument cables with shielded cable. Then to get rid of our hunting problems up here we installed electronic controls than pneumatic controls for a faster response on the main drain valve and that got rid of our hunting problem. We replaced the Barton level indication system on the buffer helium recirculators and completed and issued a moisture ingress manual to provide the operator with some actions that he could take after the event to mitigate the consequences of continuing moisture ingress.

Along with the items that the committee did, we also considered other items and for whatever reason rejected them. We had a suggestion come before the committee that we, right now in the loop logic of Fort St. Vrain, we have A and B circulators in one loop and C and D circulators in another loop. A suggestion came in that we cross that logic in that we pair A and C circulators and pair B and D and the objective was to reduce the loss of losing two circulators in a loop. That represented, however, significant control changes and involved separation and segregation criteria that we were trying to accomplish. It got us into trouble with our fire protection programs so, overall, we rejected that suggestion.

It was also suggested we provide high pressure separator for the buffer supply differential pressure indication to the control room. We looked at that but there were check valves in the circulator cartridge so we had to reject that. We did look at the indication that was in the control room which essentially provides the same kind of information; it doesn't come out from the same tap points there and we did enhance that indication in the control room. There was also a suggestion that on the main drain we have a one-inch bypass valve around that main drain valve, and there was a suggestion that we utilize the main drain, the large valve for setting rough points and use the one-inch bypass valve for fine control. We looked at that in some detail. We simulated that on the computer and we found in the end that we were not able to control on that basis as well as we control now, so we rejected that thought. It was also suggested that we replace the main drain valve with a hydraulic valve. At least at that point in time we had had circ trouble with hydraulic valves in the plant. We did not consider that very seriously and were working at that time on using a digital valve for that purpose anyway. A digital valve is a stacked wafer type of valve that openings up at different ports as the valve comes open.

MR. SIESS: When you said that I thought of the

Dutch boy with his finger in the dike.

MR. WAREMBOURG: It is just a different porting of the valve as you open it up. You control it on a digital basis so that --

MR. SIESS: Okay, I see.

MR. WAREMBOURG: Then we also had a suggestion that we modify the system to run without a buffer helium recirculator for a period of time. We looked at that and the control system requirements only complicated the issue and we rejected that suggestion.

Then we had several items left over in the Moisture Ingress Committee which is now turned over to the auspices of the improvement committee. Some of those suggestions are summarized, one is to remove trip inhibit for second circulator in a loop. Now if you upset the circulators, we've got an interlock in there; so that it will avoid a loss of forced coolant we'll keep one on the line. As a result of that, we have taken volumes of water up the shaft of a circulator that is kept on line for that purpose, so the suggestion is to remove that inhibit from a second circulator loop. We have that under evaluation because it does increase the possibility of a loss of forced coolant accident. So we are considering that more carefully before we do anything along those lines.

Another suggestion was to install a moisture slinger on the shaft of the circulators. The idea was to as the water comes up the shaft was to throw it to the outside and prevent it going further up the shaft and into the PCRV. We've looked at that. It will require major modification to the circulator cartridges. It is obviously effective only when the circulators are operating at relatively high speeds and that's not been when we get the major moisture ingress. We get it when it is at slow speed or shut down. That may be worth considering, but certainly not by itself. If we were to modify the cartridge for some other purpose we may want to consider this.

There was another suggestion to install digital valves in the main drain line, as I discussed earlier. We did discuss a digital valve and installed it on one circulator during the outage; however, there wasn't sufficient clearance and it bound up in the test. We've since removed that and returned it back for engineering evaluation. We have not given up on the digital valve process, but it needs a little bit more engineering. Modifications of the control system for the high pressure separator main drain have been completed. We have now a whole electronic control system on that.

Replace the buffer helium recirculator with an eductor. The idea was to replace the rotating machinery with a more passive device. Again, by itself, that change does not look attractive to us; however, possibly in combination with other changes that might be worth considering.

There was also a study to replace the main drain valve and in terms of its operation, to go to a passive system and install a fixed orifice drain system with drainage being provided with a jet pump. We've looked at that, a fixed orifice drain system by itself we don't feel will accommodate the various circulator modes of operation from shutdown to start-up to routine operations. That change, however, combined with others, may be worth considering.

There was also a suggestion we install a full flow or bypass flow filters in bearing water supply lines. We have looked at that initially, and the pressure drop associated with those filters with the kinds of minute quantities that we want to take out are excessively high, and I don't know that we'll be able to do anything with that or not without having to change the bearing water pumps.

MR. WARD: Where did is this stuff come from that you filter?

MR. WAREMBOURG: It is a closed loop system. You pick up magnetite within the system from the piping systems and so forth and they tend to deposit that in the bearing water cartridge.

There's also a suggestion that on the high pressure side in terms of the bearing water supply and the backup bearing water supply, that we consider digital valves for those. Their control and response time is much better than the pneumatic valve. Given the experience we've had with the digital valve we're not pursuing that one very actively.

There was a suggestion to replace the laminar flow elements in buffer supply lines. Very difficult to keep in calibration. They plug up easily. We looked at replacing those with first a Venturi-type meter, but we couldn't find one that would give us the flow range we had to have so we rejected that idea. We went to a resistance temperature detector-type meter. We thought that would give us broad enough control but when we installed it and tested it, it didn't work.

We're back to the laminar flow elements now. There was a suggestion we replace the three half-capacity bearing water pumps with full-capacity pumps. We looked at that. Because they are safety-related they have to be on the diesel generators and we cannot pick up full-capacity pumps with our diesel generators, so we've rejected that for the time being.

The last activity suggestion that's still in the improvement committee in terms of items turned over from the old committee, was to eliminate the circulator trip on positive buffer-mid-buffer. When you have a positive buffer-mid-buffer indicator, you've lost your primary buffer seal and coolant is coming down the shaft of the circulator. The idea of the suggestion, let's just eliminate that transient and let the circulator run on that basis and let the operator take the action to terminate that. The problem with that is as primary coolant comes down the shaft it ends up in the low pressure separator. We lift the relief valves and that activates our emergency response plan, and we're not too anxious to do that, so that suggestion now is being carefully evaluated.

In terms of new items that the improvement committee is considering, we're looking at the possibility of floating bearing water pressure with PCRV pressure, the idea being as you start up you have relatively low pressure in the vessel, something like 300 pounds or so, and you have full bearing water pressure in the cartridge, so your impetus at driving water up the shaft is much greater. If we could control bearing water pressure more evenly with reactor pressure, at least if you had a transient, the driving force and the amount of moisture would be significantly reduced.

We're still looking at the control system of that to determine how much more complicated that is versus and whether it is worth that effort. There's a consideration to add an uninterruptible power supply for the system 21 computer because a lot of that instrumentation is not on essential buses. We have made modifications to provide backup power supply. Where we couldn't get them on accession buses we provided portable battery packs. We have an interruptible power supply.

We are currently investigating a hydrostatic seal for the upper part of the helium circulators rather than the static labyrinth seal up there now. The principle of the hydrostatic seal is as you upset the pressure differential in the helium circulator cartridge you would form a positive seal in the upper end and avoid moisture going up the shaft. That obviously requires a major revision for circulator cartridges.

We've just received the preliminary evaluation by Westinghouse. We've not evaluated that yet and don't know at this point in time whether that's going to be a feasible consideration or not. We're also evaluating modifying the helium circulator lower water drains. Within the original design of the circulator there were two drains applied at the lower part of the circulator primarily for balance. We've since found in operation that we really only need one of those. If we could plug up one of the other drains that would reduce the amount of water. We believe that's a worthwhile modification. We're of course not going to pull all four circulators to do it, but as circulators are refurbished we'll accomplish that modification.

There was a suggestion to revise the control board in the control room to improve the operator control room interface. Of course, revisions to that control panel have been designed and are part of the control room design review process and are scheduled for installation during the next refueling.

Then we get into some of the biggies: Investigate the possibility of installing motor-driven hermetically sealed magnetic bearing circulators. That would mean replacing all four with a motor-driven circulator with magnetic bearings. That would ultimately make sure we won't get moisture up the shaft. Larry will discuss that in more detail. That proposal has been developed. It has been presented to the committee and is being considered along with various other alternatives.

The other possibility was to install a motor-driven circulator but use oil bearings. Right now that's not a leading concept. We really don't look forward to having oil in the vessel, so that right now is not receiving a lot of attention.

Another one that has a lot of promise is to investigate the possibility of using a magnetic bearing concept retaining the steam water drive rather than going to a motor drive. The initial engineering work on that project has been released to Proto Power Corporation under the joint

EPRI/PSC program.

We are investigating and evaluating modifications that permit the maximum use of existing systems. GA has submitted a proposal which we are evaluating currently. This incorporates the fixed orifice drain, eductors rather than circulators, jet pumps, it is going with modularized auxiliary units, everything is on one modularized unit. All four have their own separate auxiliaries. That system would eliminate backup bearing water. It would eliminate the accumulators and of course provide a more passive circulator auxiliary system. It is a rather extensive project, however, and would require extensive modifications in the field and considerable down time within the plant itself, so obviously that's something that we're going to have to consider very carefully in terms of which direction we're going.

We have evaluated system 23 helium purification system. When we get moisture in the vessel, it tends to freeze up the front end and by the time we regenerate that the other train is frozen up and we don't have either purification train to operate. We've installed some chilled water units on the front end to reduce the dew point. We have it down to about 38 degrees and find that that has improved our operational experience on that system and are continuing to monitor that.

We have also developed some simulation

capabilities within the helium circulators and have one helium circulator pump on the control packages and are utilizing that for operator training. That is helpful in terms of operator training and experience.

With that, that's about the activities that we've undertaken in the moisture ingress area, unless there are some specific questions. As you can see, it is obviously one of the primary areas that we're considering and we consider it to be one of the most important areas in terms of improving the availability and capacity factor of Fort St. Vrain.

The next is helium circulator bolting, and Jack touched briefly on that this morning in terms of problems we've had with high strength bolting in the helium circulators at Fort St. Vrain. Circulator C 2104 was removed in January 1984 and sent back to GA for refurbishment. Circulator C 2102, which had been back at GA, was sent back on site and was reinstalled in place of C 2104. Jack indicated subsequently we discovered that we had a bearing water leak in the supply line of 2102. We had to remove it and send it back to GA. At that time, 2104, which we had sent back in January, was all torn apart. There wasn't a chance of us getting that turned around, so we made the decision to repair 2102 and get it sent back to the site.

However, in the reassembly process of C 2102, one of the 24 high-strength bolts for the primary closure, 30-40 bolt, failed during torqueing operations. Subsequent evaluations were made and it was determined that the failure resulted from stress-corrosion cracking. We immediately then initiated action to evaluate the high-strength boltings of the circulators. In looking at the circulators we discovered some 31 different fasteners that were utilized in the helium circulators. Most of those did not end up being high-strength fasteners. Some were not in contact with primary coolant. When we got done with the evaluation we ended up with four primary areas of high-strength bolting which were subject to contact with primary coolant and possible stress corrosion cracks.

MR. SIESS: I get mixed up. Which end is up?

MR. WAREMBOURG: This is the Pelton wheel on this end. This is the compressor on this end. Of the four areas, primary closure bolt is located right here, and then we discovered we had some duct hold-down bolts located here, the bolts which bolt the rotor to the shaft are located there, and then we had some stator bolts that bolted the stator to the machine, so those are the four areas of high-strength bolting.

MR. SIESS: Primary closure, and all the bolts have failed. What would happen?

MR. WAREMBOURG: You bring primary coolant into this end of the machine. If you have relatively low steam pressures down on the low end of this thing and bring primary coolant up on this end, what's going to happen is you're going to bolt this whole torus in here, you'll end up with primary coolant down the circulator. This would end up with primary coolant coming down and into the reheat piping, so you really don't have any secondary closure.

Once you get in the Pelton wheel cartridge you don't have that secondary closure there. You would get into the steam piping and you could close the valves but you would get that coming into the steam pipe. No breach in the containment as such, because you still have a secondary closure.

MR. SIESS: But that's no big deal to get that in the steam pipe, is it? Steam piping operates at what pressure?

MR. WAREMBOURG: Steam piping of course is designed -- the hot reheat pipe is designed for automatic closure when it sees radiation, because the hot reheat system runs at 600 pounds.

MR. SIESS: That would be lower than primary coolant, well within the capability.

MR. WAREMBOURG: Yes. The failure of the other bolts would cause displacement of various circulator parts and they would virtually result in circulator damage, but not

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in any problems with reference to the health and safety of the public, so really the only bolts that were involved with any consideration with the health and safety of the public was the primary closure bolts.

Of the four areas, the primary closure bolts are designated as 300-40; H-11 high-strength ferritic, CD plated, 260,000 ultimate, 215,000 yield, 23 bolt circle. The stators have a 12-bolt circle and 7/16ths of an inch in diameter. On the duct hold-down bolts, that's a 12-bolt circle. 5/8ths inch in diameter.

In terms of the inspection program then, after the initial inspections on 2102 and 2104, recognizing that the rotor bolts were 7/18 Inconel, we didn't find any problems with the bolts in either of these circulators. They were eliminated from the inspection program.

The remaining areas where we had H-11 and A-286 bolting, we launched the following inspection program. All the bolting was to be visually inspected on the circulators. Some were inspected using fluorescent liquid penetrant. Bolts were selected at random and examined macroscopically and microscopically. Bolts were selected at random and leached in demineralized water and analyzed for chlorides, and some bolts went under the material chemistry program to determine that we did have the appropriate bolts for that application.

In terms of the findings, on circulator C 2101, primary closure bolts H-11, we looked at 24 visually and could not find visual problems. We took seven bolts at random. One of them ended up with indications of stress-corrosion cracking. There was minor pitting in six of the seven, but only one was evident with stress corrosion crack. The stator hold-down, we selected six at random. We did not find any stress corrosion cracking. We observed cracking in the threads of four bolts. The cracking, however, was old and we felt that it most likely occurred during the original anufacturing of the bolts. We did not find any defects in the duct hold-down bolts and of course we did not check any of the rotor bolts on this circulator. In terms of chloride analysis on those bolts, we had about 2 micrograms per centimeter square in terms of chloride on those bolts.

MR. SIESS: Where do you think the chloride came from?

MR. WAREMBOURG: We feel it primarily comes from the fuel. Within the fuel manufacturing process itself there's a residual amount of chloride that's left on the fuel process and we feel it is leached out of that fuel.

MR. SIESS: Do you mean the fuel particles?

MR. WAREMBOURG: Yes. There's slight amount of chlorides in the cable but the major contributor has to be the fuel.

Circulator C 2102, we looked at 23 bolts visually. One had already failed during torqueing operations. We took six for metallurgical exam and of the six, three of the them ended up with stress corrosion cracking. Typically the stress corrosion was found in the top of the three threads nearest to the shank that were not engaged.

Of the stator hold-down bolts we looked at six at random. Again, we observed some cracking in the top of the three threads not engaged. On four of those initially we could not determine whether or not to make a determination whether or not it was stress-corrosion cracking. I guess in the final analysis, as we've looked at that we did find some silver plating in the cracks and feel that the cracks were rather old and probably were the result of original manufacture and not stress corrosion.

MR. SIESS: That footnote you don't think applies?

MR. WAREMBOURG: We don't think there was stress corrosion there. We looked at the duct hold-down bolts, no problems there. We looked at the Inconel bolts on this and did not find any problems there. The chloride analysis on this circulator was a little higher than the others. This turned out to be 13 micrograms per square centimeter on C

2102. That was the one that kicked the whole program off.

C 2103, again we looked at 24 visually, no problems. We selected, again, six at random of the primary closure bolts, and found superficial rust within the thread tips, but we were will within the specs for that bolt. We observed one bolt with stress corrosion cracking found in a part at the very beginning of the partial thread near the shank. None of the others exhibited any stress corrosion cracking and likewise none of the other areas of the circulator exhibited stress corrosion cracking. The chloride concentration was 3 micrograms per square centimeter.

2103, that one came up clean all the way around. We didn't find any stress-corrosion cracking in any of the bolts. We found no indications on any of the rotor areas, and the strange thing about that is that when we leached this out it had the highest chloride concentration of any of the circulators. It ended up with 24 micrograms per centimeter, and so we really don't have an explanation as to why it had the highest chloride concentration but no stress corrosion.

MR. SIESS: You are averaging one in five or one in four of the bolts you are looking at having stress corrosion cracking. The probability of a sample not having any is not so terribly low.

MR. WAREMBOURG: That may be true. On 2105, we did again look at six bolts from the primary closure. We

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observed two with stress corrosion cracking but this was a little different in that the stress corrosion cracking did not appear in the threaded area. Now we found stress corrosion cracking instead in the heads of those bolts. We did not find any problems in the rest of the bolts. This one ended up with a chloride concentration of 4 micrograms per square centimeter.

MR. SIESS: You mentioned that when 2102 was sent for refurbishment, it was all torn down. I would assume that when these things are refurbished most of the bolts have been removed. Some of them have to be.

MR. WAREMBOURG: The bolts in the past were removed but were replaced. We did not change the bolts.

MR. SIESS: But were they inspected?

MR. WAREMBOURG: At least there was -- no, we have no indication that they went under any direct inspection in the past, other than just looking at them.

MR. SIESS: Now, were they not inspected simply because these materials were not expected to be sensitive to stress-corrosion cracking or fatigue cracking or --

MR. WAREMBOURG: I guess they were not inspected specifically because we didn't expect any chloride stress-corrosion cracking. We didn't expect any chloride in the primary coolant of the vessel, so that was a surprise.

MR. SIESS: Has it been known in the past to be sensitive to high stress corrosion?

MR. WAREMBOURG: Yes.

MR. SIESS: You knew the material was sensitive but didn't think you had the chlorides?

MR. WAREMBOURG: Right.

MR. WARD: A 286 bolts, you didn't have any problems with them but replaced them anyway?

MR. WAREMBOURG: We felt the problems were original manufacturing problems. We went ahead and replaced them all with Inconel high-strength 718. That gets rid of the problems. You might as well replace them while you got them out. As far as overall conclusions, we did determine that we had some defects that were most likely originated under original manufacture and assembly. We concluded some of the cracking was definitely caused by stress corrosion. We looked at various conditions within the core of the Fort St. Vrain and did determine that we did have conditions which were conducive to chloride stress corrosion cracks. We had the presence of chlorides and moisture and at times the presence of oxygen, especially during refueling periods.

Again, we replaced all high-strength bolting that contacted primary cooling with 718. In addition to that, we launched into a major program to investigate all areas within the PCRV primary coolant system in terms of those that might be subject to chloride stress corrosion. We subsequently summarized that in a report to the NRC. We looked at steam generators, what have you, thermal barrier hold-down bolts and those kinds of things, and analyzed what might be happening to those. That report is also documented. With that, that's all I've got. The next one on the program is Larry Brey.

MR. BREY: I'm Larry Brey. I'm going to talk about future circulator development. Don pretty well addressed the Fort St. Vrain improvement committee. It is obvious that with a mission of trying to improve plant availability and reliability that we would zero in and spend a great deal of our time on trying to resolve our moisture ingress problems. A good example of some of the time that we have taken just to remove the moisture, over the past many, many years, out of the core is just in the last six weeks. We've spent six weeks where we could have been generating 35 percent power instead slowly raising reactor power trying to drive moisture out of the core. If you look at the history of Fort St. Vrain, that's indicative of what has happened over the years.

So the improvement committee has really spent, I would say, the lion's share of its time trying to reconcile the moisture ingress issue as it pertains to Fort St. Vrain. This is an artist's concept of a circulator. I'll put it up for just a minute. We have the helium impeller. There's a shaft about three feet long, a single-stage steam turbine which is the main drive on the circulator and the backup drive is a Pelton wheel which uses either feedwater, condensate or fire water as its motive source. This is a little bit more detailed for what I want to get into. I'm going to set the circulator on its side in order to read the material, but again the shaft of the circulator, a single-stage helium impeller. On our circulators, we have high-pressure, high-volume water, which is the lubricating mechanism for the bearings. In normal operation a circulator will utilize bearing water at between 6- and 700 pounds positive vessel pressure to force about 180 gallons a minute of water through each circulator bearing cartridge.

In the case of our circulators we have an upper general bearing, a reference thrust bearing, normal thrust and another journal bearing. Some of the concepts that we've looked at Don has already addressed and I'll skip over those, but let me go into some of these others in more detail.

First of all, Don mentioned that we looked at replacing our existing circulators with new circulators that feature magnetic bearings all the way around, motor-driven circulator which is hermetically sealed. In this case, the motor drive would be about a 5500-horsepower synchronous motor, a dual winding affair with more or less the backup or the class one winding which takes the place of the Pelton wheel integral with the motor.

About a year ago we looked at this concept. We performed a feasibility study, found that it was feasible to go into Fort St. Vrain, but it does have a number of drawbacks and we have since set it aside for future consideration. We're looking at other things right now. Some of the drawbacks: First of all, $40 million if we want to replace the circulators.

Secondly, if you look at the issues that are facing us, we would go completely to magnetic bearings, essentially do away with our high-pressure water bearings, doing away with the Pelton wheel, with the single-stage steam turbine, many major licensing issues, so the improvement committee looked at any number of other concepts.

Don described this second one, GA Technologies provided it's proposal to us to take the existing circulators and make many, many major modifications to them. This concept still rests with the committee. We're evaluating it, the possibility of either taking it in its total or taking parts of it or not accepting it at all. A proposal came in which would essentially take our existing circulator, keep the steam and Pelton wheel drives, but replace the journal and thrust bearings with magnetic bearings. We looked at this study and we decided that we would opt for a little bit different type of scenario which I'll describe later.

Essentially, this does not address a very important problem, and that is, how do you seal the shaft if you do away with your sealing mechanism in total, in other words your water, on the shaft, how would you seal it to prevent or to make your buffer system work properly? Don mentioned, then, Westinghouse. They have given us an initial proposal or a preliminary engineering evaluation on putting on hydrostatic seals. This is still being evaluated.

What I want to concentrate on right now is on the last proposal that you see. That is taking essentially new circulators with the basic components that exist on our circulators, but doing away with high-pressure, high-volume water which is needed for the thrust bearing, and replace that high-pressure, high-volume water essentially -- or actually replace the thrust bearing, the water bearing, with a magnetic bearing. We would then use low-pressure water, say about 15 pounds pressure above the vessel pressure, at a limited supply and a limited volume basis to supply the lubrication to the journal bearings and also provide a sealing basis for our buffer system, as it is presently constructed to work properly, so we don't get primary coolant down the shaft in great quantities.

The improvement committee, as of the 14th of February, went ahead and authorized a preliminary investigation and a feasibility study into this type of circulator concept. There was a proposal provided by Proto Power Corporation. Proto Power brought together James Hughton Company out of Glasgow, Scotland, probably the foremost circulator designer for gas-cooled reactors in the world, S-2 Corporation, a French corporation that we understand to be probably the leader in the world in magnetic bearings, and they have brought these people together and provided this proposal to us.

The proposal which we've authorized is really in conjunction with Electric Power Research Institute. Public Service, during the initial phase, would probably pay in the area of $800,000, and the Electric Power Research Institute would fund it to approximately half a million dollars. But this is the concept that we're looking at or that we authorized to look at just recently.

We have other concepts that are still under consideration that I mentioned and it could very well be, in all likelihood we'll take a dual approach and look at a couple of different concepts in parallel just to see where we're going. One of the things, if this type of circulator were to be the one that we would decide on, it would cost in the area of about $20 million to completely replace the circulators, and we're looking at five years down the road, so we have to live with our existing situation, making modifications like those Don mentioned on our existing circulators for the next four years or so. We would have to have a plant outage which may last up to a year to replace the existing circulators with new circulators. It is a very big decision. However, we've seen in the past where moisture ingress seems to be by far the major culprit in poor availability of Fort St. Vrain. That's pretty well all I have. Any questions?

The next section is on control rod drive. I guess virtually everything dealing with our control rod drives, Frank Novacheck will talk about, the failures, overall modifications and maintenance.

MR. NOVACHEK: We'll go to the top part of the reactor vessel now, and start out with a description again of what happened on June 23. The event actually started on June 22, 1984, when we had a failure of a sudden pressure relay which caused a trip of a transformer and consequently an upset of the circulator system. We reduced power at that point in time. However, based on indications from our moisture monitoring system, we felt that it was acceptable at the time to maintain power. Later on, because of the moisture in the reactor vessel, we had seen some icing occurring in the purification train and so we decided to take the power down all the way in an orderly fashion. While we did that and following a trip of the turbine, the high-pressure reactor scram is on a program with reactor

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power as indicated by the circulator inlet temperature. As we were cooling down, it indicated that the power level was lower, and the pressure in the reactor vessel was at the high end of the program, and that is in fact what caused the scram. It wasn't actual vaporization of the moisture in the reactor vessel that caused the high-pressure condition.

Following that, and that was on June 23, very early in the morning, during the scram, six of the 37 control rod drives failed to insert automatically. Based on -- and within 20 minutes they were driven into the core Based on an indication that we had at the time, we couldn't really establish what the problem was, but we did know that in 1982, February of 1982, we had experienced a similar event where two control rods failed to scram during subcritical activities. The only correlation between the two events was high moisture conditions in the reactor vessel, so we started looking at that as the primary contributor.

I would like to take this opportunity to go through some of the design characteristics of the control rod drives. I'll be referring to a few drawings here. Starting out with the control rod drive itself, this -- although the writing is upside down, this is the orientation as it sits in the PCRV. The PCRV stands down to this point. The actual drive mechanism, shim motor, orifice drive and that sort of thing is in this area. Secondary closure and primary closure, at this point. And of course each of these is cooled with liner cooling system, tubes inside the concrete.

Inside that top area, then, is the top of the control rod drive. This is the shim motor that is used to withdraw the control rods, and in the June 23 event, also to drive the rods in. The gear train, three-stage gear train, with approximately 1150 to one gear reduction ratio. A hub here, there's two grooves that are deep grooves that the control rod cables are wound up spirally onto the hub and some pulleys to align them into the guide tubes properly. The orifice drive here that drives a lead screw that opens and closes the valve used to control primary coolant flow through each reactor reading.

There's also a break on the shim motor that is activated when you withdraw the control rod. The break is set, and during a scram, the power is removed from the break and the motor so that the rods free-fall into the core. This is a slack cable housing assembly, the slack cable switch. This is a fulcrum in this area. In the event that you were to lose weight, say that you had a failure to scram and it was due to a control rod getting locked up in a channel in the core, you would lose weight on one of these cables, it would cause this to pivot and click switches that tell you you have lost weight or actually lost a control rod.

In addition, in this area, there are cams that tie to another and other gear reductions that tie to position indication. There's a 10-turn pot on the same -- two 10-turn pots on the same axle that provide redundant position indication. There's in-limit switches, out-limit switches, fully withdrawn switches, and once you remove a control rod from the reactor you have full retract switches. So you can fit it into the auxiliary transfer cask.

MR. WARD: Where are the in and out switches?

MR. NOVACHEK: I don't have a drawing of that, but what it is, the gearing is this. As the hub rotates, it is geared off that and there are posts that provide a mechanical switch as they -- it is on the back side of the housing. This is a better description of the inside of the hub there. You can see the grooves for the cables here, the shim motor here and spindle that goes all the way through, and then the first stage, second stage and third stage gears. And these are the cams here for the in limits and out limits.

Another feature of the control rod drives is then, to maintain radiation levels in this area to roughly one review per hour. You have a biological shield that sits here and cable seals here to minimize primary coolant contact into this area.

MR. WARD: One of those seals --

MR. NOVACHEK: Minimizes the inner diameter. It is a circumference seal, two pieces that come together around a cable, and it minimizes the open space between the cable and the inner diameter. There's no contact, if the cable is intact. I'll get to that. A final major -- well, I guess I can show you -- yes. Let's go back to this a second. You can see here the reserve shutdown system is actually a hopper. The top part on this is the fill plug where the material is loaded into the hopper.

And then the bottom of that hopper is shown here, and there's a rupture disk that when the delta P across this rupture disk gets to an area of 165 pounds, psi, that rupture disk will blow, material goes down into the reactor region. The orifice valve here -- and like I said, the lead screw for the orifice valve turns and raises and lowers windows in this area. Controls primary coolant flow through the regions.

MR. WARD: How does the pressure --

MR. NOVACHEK: I had that as a backup slide. I'm glad you asked that. This is the reserve shutdown system for all 37 regions. You have either helium storage system here or the primary that we take credit for is helium storage cylinders, just helium bottles. And from the control room these hand switches are activated and they provide bottle pressure to the hoppers and rupture them that way. There's backups with nitrogen and that sort of thing.

So following the event in June, we went into a root cause identification phase. We went to the six control rod drives that failed to scram and like I said earlier, the primary thought at that time, due to the link from the February '82 event, was moisture. We examined those and rebuilt them.

We also looked at an additional four to see if we could get any more information, because the information we got from the first six wasn't as conclusive as we thought it might be. So during all these processes, we looked at the moisture effects, the shim motor condition, gear train condition, potential lubrication incompatibility.

The moisture effects, the reason we looked at that was because of some openings. Typically the pump for the CRDs comes in this way and comes down through here, through the cable seal area and out the bottom, because there's windows in this area of the orifice valve and there's also some large holes for handling the control rod drive internal parts. The pump flow we thought maybe wasn't sufficient to keep primary coolant through convective flows from coming up into the device, so we looked at that.

The shim motor condition, we were interested in the gear on the shim motor and the bearings. At that point, to turn a shim motor you are talking on the order of six or seven in which ounces of torque is all that's necessary to turn those. Then the gear train condition, which isn't quite as sensitive.

As a matter of fact, as we found out later on in the program, we had installed bearings in backwards on a couple of the drives and that did not inhibit the free-fall of the control rod. Also, we had lost a slack cable bushing container which caused the hub to brush up against the cables; and that's roughly equivalent to the second stage of the drive, and that didn't cause any inability to scram also.

So we had to concentrate mostly on the shim motor. Potential lubrication incompatibilities. Those are lubricated with moly disulfide. We were concerned with the moisture and temperature. Perhaps we were getting sulfuric acid buildup but there was no evidence of that. Other mechanical obstructions, maybe with the convective flows into the drive using graphite elements there might be dust, graphite dust in the mechanisms, rust or anything like that, because of the previous moisture ingresses that we thought might get involved in the gear trains and finally temperature effects.

There were studies done to determine whether high temperature on the shim motors or the gear trains themselves due to clearance between the moving parts might have caused a restriction. Another mechanical obstruction would be the possibility of a cable hanging up and maybe that's what caused the failure to scram.

When we got done with them, in the study of the moisture effects and the lubrication incompatibilities and debris theories, we actually looked at some of the shim motor bearings. And in feeling them -- I guess it was kind of a touch thing -- but in rotating the bearings with your fingers, you were able to feel a significant difference between a new bearing and a bearing that had been installed in the core, so we took some of those, cleaned the material out of them using ultrasonic sinks and analyzed the debris inside there. The debris turned out to be normal wear products.

In other words, the idea of convective flows bringing foreign material into the drives was discounted, and it was pretty much concluded that that resistance to motion in the bearings was probably sufficient by itself to inhibit scram. We still have not been able to totally rule out that moisture may have aggravated the situation.

During our studies, we experienced three other significant failures in our minds. The first one was that we started seeing CRDOA instrumentation anomalies. We were getting in-limit switches and out-limit switches activating at the same time. We were getting various potentiometer problems, retract switches, slack cable light switches coming up, that sort of thing. That was significant from the standpoint we wanted to make sure we knew where the rods were at any point in time. We had been moving one of the control rods from the core to examine it in hot surface facility, and we tried to close the shutter on the auxiliary transfer cask and it wouldn't close all the way, so we had a slight cable anomaly.

As it turned out, there was a control rod hanging out of the bottom of the cask, I would say probably about that far, and what had happened was that the cable got tied up. There's a single strand that had broken, and it got wound up in the cable seal area here, and when we tried to withdraw the control rod, the strength of that, along with the stress-corrosion cracking, caused a brittle fracture of the cable itself, and the control rod continued to hang in the cable seal area because it was bound up. That's why it was hanging so low. We had to cut into the drive into these access windows to get at it and get our samples. The other significant problem was the reserve shutdown material event where the boron carbide balls were conglomerated and caused bridging and not all the material came out. Milt McBride will be discussing that in a lot more detail.

After finding out all that information, a decision was made to refurbish all 37 of the drives. Based on those three major problems and the other problems we experienced, we decided to cover all these objectives: refurbish shim motors and replace bearings in their entirety, refurbish gear

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trains, replace instrumentation, replace the stainless steel cables which is 347 stainless steel, with Inconel-625, replace reserve shutdown material with material of different specification; and Milt will get into that. It is actually a lower B-203 impurity specification. Install temperature monitoring devices. Previous to this only certain drives were instrumented with temperature devices, and due to the interest in determining whether or not that is a potential problem, we decided to instrument all of them. Install pump seals to close off the windows and openings that I discussed earlier, and make better use of the pump flow and reduce the convective flow into the drives. Refurbish the orifice drives and replace other materials in the drives that were susceptible to chloride stress-corrosion cracking with more suitable materials.

This shows where we put the temperature devices. We have one at the top of the drive, one on the shim motors, which is the critical area, and one at the orifice drive.

MR. WARD: What sort of temperatures do you expect to see there if you don't have excessive convective flow or whatever?

MR. NOVACHEK: We have surveillance in place, anything over 215 degrees -- we see over 215 degrees requires the station manager's approval at this point to continue. We're right now in the process of qualification of these

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drives up to 300 degrees.

In order to accomplish this in a timely fashion, we really had to scratch our heads and come up with some new equipment to handle all 37 drives in a timely fashion. So we came up with a system that would allow us to work on five drives at the same time. This took a lot of money but we were able to meet our schedule by a significant amount. We had to modify our hot surface facility, we had to put stands in the equipment storage wells to support them; and I'll go through these in better sequence here.

We needed a new crane, vacuum cleaner to suck out the reserve shutdown balls that were bad; we had to have a new transfer unit; we had to create areas to work in a clean room environment on the shim motors and control rod drive gear train components because of the tight tolerances there; and we had to minimize the activity, personnel exposure and contamination on the fuel deck, so we went to great extremes to insure that we were decontaminating everything as much as possible. The hot surface facility modifications were probably the largest.

We installed all this equipment here. To just run you through, we would take a control rod from the core, put it into this penetration here, and this is actually a drawing of a control rod in the position. We would drop the rods down into these holes here. They are actually tubes, and at the Clevis ends they are supported by locking mechanisms here. The bolts were removed, the Clevis ends of the cable were cut off and discarded, and the cables were pulled up from the top and also discarded. That got rid of the hottest portion of the drives.

The next hottest portion then was the orifice valve, so we would remove the control rod from here and move it into an equipment storage well and set the orifice valve down on a stand so we could work on the rest of it and not drop off the orifice valve, and we pulled the 200 assembly or gear train and shim motor assembly and the orifice drives and biological shields and seals. We refurbished all that equipment, installed new cables, and ran it back through, connected back up the orifice drive and the whole works and moved it over to this station, then, where we changed out the reserve shutdown material, and replaced the ruptured disk and did the pressure testing, and then it would go back to that position, run your post-maintenance testing and transfer it back to the reactor.

MR. WARD: Are the orifice drives, are they hot because of surface contamination?

MR. NOVACHEK: Actually it is activation. They sit on top of the elements on the core.

We started the refurbishment program in February of 1985. The first drive was a learning experience. The documentation that we had on control rods was limited at best. Ended up having to pull some people out of retirement from GA's bodies and get them to help us in the development of our procedures and that sort of thing; but it was actually looking at the first drive that told us exactly what to do, so there was quite a bit of procedural enhancement that went on. The first rod took about three weeks.

Subsequently, we got into a track and finished the last drive in mid-June. I think it was June 12. In order to confirm operability we went through a number of tests. One was to asses the shim motor wattage characteristics as you drive the rods in and withdraw them. Also the scram time, how long it took for the rod to go from full out to full in. The back EMF, which is something Mr. Craun is going to discuss after I get done here, which is, we believe, a sensitive mechanism for determining if there's any debris in the control rod drives that might affect scram. Since it's an inductive motor, as you scram the control rod it gives off a cycle and that sort of thing. Any blips in the electronic signal coming out would be indicative of some sort of restriction or obstruction.

MR. WARD: What is the normal drop time for the drives?

MR. NOVACHEK: The upper limit is 160 seconds.

MR. NIEHOFF: The normal is 132.

MR. NOVACHEK: It is an inductive motor with a capacitor bank on each of the three phases. It limits the velocity of the rods going in. They would go in much faster without. We also, while the drives were removed, we measured the torque delivered at the motor through the gear train with the rods connected, or an equivalent weight of the rods connected, which gave an indication of the gear train deficiency; and we took measurements of the torque to rotate the motors themselves and also tested all the position indications, those that were redundant made sure that they kicked at the same time and that sort of thing.

We identified a few other problems. The first was shim motor bearings. We got through the second or third control rod and noticed the shim motor bearings had eight ball bearings where the specifications called for nine in the bearing itself. This had to do with miscommunication between the manufacturer and the plant, and since they made the original ones, a lot of assumptions were made as a result. Nonetheless, there's an engineering study and various tests that were performed to demonstrate that the eight ball bearings were very good for this application as well, so we went ahead and stayed with those.

In looking at the first drives we saw rust on the sides of the drives, not necessarily where the teeth mesh, but on the sides of the drives or the gears themselves, so we figured it would be a good idea to clean them up and relubricate them. That's a pretty extensive process and includes burnishing the gears and that sort of thing with a dry film lubricant.

We also discovered that some of the shim motors stator, the epoxy coating was cracked so we had to paint some of the shim motor stators. And finally, the biggest problem was a slack cable bushing retainer. They are dissimilar metals than that used in the hub of the drive, this being the hub, and then in here was a bushing retainer here.

Okay, what had happened was due to the dissimilar materials, the temperature coefficients were different and this retainer was popping out, allowing this hub to, by the weight of the cables on it, fall down in this area and rub against the slack cable switches; so we had to put in a modification on all the drives then to retain that retainer.

In summary, besides the slack cable bushing retainers, then we installed new Inconel cables on the drives, replaced the reserve shutdown materials with low B 203 specification material. We replaced the shim motor bearings, we replaced stainless steel parts susceptible to chloride stress corrosion, replaced resilient parts, installed the pump steels that limit convective flow into the mechanism and installed the temperature monitoring devices.

MR. WARD: The reserve shutdown balls, what sort of a program do you have to routinely check those? Are they just dropped occasionally or looked at, removed?

MR. NOVACHEK: As part of the preventive maintenance program that I'll get into, we do inspect those on a refueling basis. It is routine on a refueling basis because you can't get at that portion of the drive during operations. As a result of the program, we got some good news out of it. That was that the radiation exposures, the painstaking efforts that we made to minimize contamination and put in the proper shielding and that sort of thing really showed at the end of the program.

There was over 120 people involved on a daily basis and the total program exposure was 29 man-rem compared to industry average of 473 man-rem annually. The remainder of the year, by the way, added another six man-rem so it was 35 total for Fort St. Vrain against 473 for the industry average. The maximum individual's exposure throughout the program was 1.51 rem and the maximum single exposure on one job where a man went into the hot cell to remove the Clevis bolt and back out was 100 millirem. So we didn't have to do this again on such a large scale, we beefed up our preventive maintenance program on the control rod drives.

On a refueling cycle frequency, those control rod drives removed from the reactor -- in other words, one sixth of the drives on a refueling cycle basis will be worked while the plant is in operation and then replaced with refurbished drives during the refueling process. The extent of PM that's performed on these, as well as the frequency -- I mean if we're operating and we see one that isn't satisfying the surveillance requirements and as far as scram time and motor, we'll work on it. The extent and frequency will be dependent on PDM testing and examination.

The special areas are basically areas addressed during the refurbishment program. You wanted to know about the reserve shutdown system. We have a surveillance requirement in the interim tech specs on the control rod drives to blow a hopper, one low and one high, on a refueling cycle basis to do chemical analysis on the material and to do visual examination of the material. We also have a visual examination of the cables to look for any indications of any sort of corrosion.

MR. WARD: When you blow a hopper, are those balls recovered and put back into the hopper?

MR. NOVACHEK: They could be, but typically we don't do that right away.

MR. WARD: You recover them and then have a chance to examine them.

MR. NOVACHEK: We have not put them back in at this point, have we?

MR. MC BRIDE: No, we haven't, no.

MR. NOVACHEK: We don't see any problem doing that other than those that split or something like that. We do blow those, the hot surface facility, by applying the 175 pounds of test pressure. Then we also checked the capacitors. That was an earlier part of the refurbishment program as well.

As far as the predictive maintenance program goes, this summarizes what we can do in and out of the core. In the core, we can take shim motor wattage readings, both insertion and withdrawal. We can take scram time readings. We can take drop rate readings. Now, the scram time you can't really do during power operation because you have one shim. You go in groups of three control rods as far as the withdrawal sequence goes so there's only three rods that are partially inserted at any point in time. The rest are fully withdrawn or fully inserted.

You don't want to do a full scram or you will perturb power significantly. The drop rate is what we use then. We take roughly a 10 second drop of the control rods which doesn't perturb power all that much. We're able to handle that with the regulating rods. Regulating rod would be an exception where we scram from two to six seconds. We're taking back-EMF data -- excuse me. We take the drop rate and extrapolate that for the whole duration of the scram and determine whether or not that's less than 160 seconds, so it is effectively a scram time test as well. Back-EMF data is collected administratively and while we're studying that, and then we can exercise the orifice drives to make sure they are free.

Out of the core we can do more. We can determine the delivered torque at the motor. The torque to rotate the motor, establish freedom of motion of the bearings, the torque to rotate the orifice lead screw and the torque to rotate the orifice motor itself to establish freedom of motion in that area. We feel confident that these programs are going to ensure that we don't have an event similar to that on June 23 and we'll be collecting data from now on, I would believe, to look for any further indications of degradation on the drives.

Are there any questions?

MR. WARD: Thank you.

MR. NOVACHEK: Next Mr. Craun will discuss the back EMF testing that I described earlier.

MR. CRAUN: This will be a presentation on the control rod drive orifice assembly back EMF test program. As a result of failure to scram, we were asked to see if we could develop a testing program that would improve our ability to monitor the performance of the control rod drive orifice ass bly mechanism. Along with that we wanted -- one of the test criteria was to ensure that we could ascertain performance while in core, so we started off on the development of the back EMF. I'll present back EMF to you in five parts. One will be a short overview of the design. The next will be a back EMF development itself, the analysis, performance criteria, planned research and development.

As Frank has indicated, the CRDOA is a three-stage gearing mechanism, cable drum here, motor over here. During the scram process, the motor itself becomes a generator. The motor is a three-phase, four-pole squirrel cage-type induction machine.

Going back to the gear train for just a brief minute, it is a 1151 to one gearing reduction. To give you an indication of the duty or the cycle -- or the duty on the mechanism itself to go from fully inserted to fully withdrawn, it requires revolution of this outer drum of 4.6-some-odd revolutions. That would take you from the full in to the full out.

Back to the motor itself. The motor itself produces 360-some inch-ounces of starting torque, produces approximately 208 inch-ounces during normal operation at 1650 rpm. As I indicated, the motor does have permanent magnets installed in it, so when the braking mechanism located off to the right here, as it is released, it becomes a generator and that controls the rate of descent of the absorber string itself.

MR. WARD: Where is the brake? I didn't see that.

MR. CRAUN: It is running off the main rotor shaft, motor shaft. It is off the diagram.

MR. SIESS: What is the diagram of that drum just to get some scale on this?

MR. CRAUN: From the first to the fourth it varies from six to seven inches. Excuse me, that's the radius, not the diameter.

As part of the original control rod drive qualification, which was based on a testing program which was the physical number of scrams, along with that they had some general design investigations. They were in three major areas. The first was to ascertain the amount of torque it would take to hold an absorber string in the full withdrawn position with the brake released. The next would be the amount of torque that it would take to have a controlled insertion or a controlled withdrawal of the rod. The next two areas were motor wattage and back-EMF voltage. Both these required -- if you recall, right on the motor was the brake which wasn't on the slide, but auxiliary to that was a mechanism which they used in the original design to vary the drag coefficient of the mechanism itself to ascertain the impact on withdrawal and insertion wattage and on back-EMF characteristics.

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As a result of those studies and some work that technical services performed in the beginning of the refurbishment program, we decided to digitize the generators' output. This basically is a representation of the motor itself, the capacitor bank. We hooked up a resistor network across it to step the voltage down. We then digitized this voltage being generated during the scram. We take approximately 4000 samples per second, allowing us to reconstruct the wave forms accurately. We get approximately 50 readings per wave form, so it is an accurate reproduction of the voltage itself.

One last point, we are -- our computer system is tied to the actual scram switch, so when the reactor operator goes through the scramming operation, it activates, triggers the computer and starts the data acquisition system. We acquire data for 150 seconds.

From now on I'll be building on some basic building blocks of back EMF. This is a fairly technical subject, and so if you have questions, please ask. Let me explain what you are looking at other than some squiggly lines. This represents time in seconds. This is a representation of the first 10 seconds of a control rod drive scram. This is an actual data set. It is on serial number 14, the data set was taken on 8/24/85. It is in core region 6. This is the back-EMF voltage. It varies from approximately 200-some-odd volts.

Now, to give you an indication of what we see here, scram time zero starts as the mechanism is coming to speed, and here we have frequency. This is the frequency of oscillation of the voltage. As the voltage picks up, we can then start measuring the threshold. As soon as we can measure and determine the oscillation sideway period, we can convert that frequency to speed. This is a representation of frequency and speed. You see the overshoot of the rod as dynamic braking kicks in. You can see here that the voltage goes through its transient peak and stabilizes. In reality, this is an oscillatory motion in here, so this would be filled. We've enhanced it here and stripped out the internal part of it.

In order to validate back EMF there were some basic concept problems. We went through a three-phase program to try to determine if in fact back EMF is telling us anything. The first thing we did, you'll notice this was for 39 microfarads. We then took a scram profile with 45 microfarads. Theoretically, a reduction in the capacitor should decrease the scram time. It should increase the amount of time it takes to come to peak velocity. It should increase that peak velocity. It should increase the steady state velocity, should increase the steady state vacuum voltage, which it did. That was the first of three theoretical --

MR. WARD: Doesn't look like it did.

MR. CRAUN: The speed is -- which one were you questioning?

MR. WARD: I can't see much difference in the steady state voltage, for example.

MR. CRAUN: You see a darker line where it is overlaid. We can enhance that if desired. The second confirmation, as I indic[illegible] takes approximately 4-1/2 revolutions of the outer [illegible] wind that cable up. As you wind it up to the fully withdrawn position, you have more leverage to activate the scram. We calculated the theoretical from fully withdrawn to fully inserted as to what that would do to the control rod's willingness to come to speed. We took a data run or set or test at various positions. The circles with the dots are the data. The linearization of that data is represented on the solid line. We felt that we were -- again, tests were confirming the theory of the concept.

The third test program was an encoded shaft pot pulse converter counting system. If you recall, back on the motor again, we hooked up an encoded shaft and a counting pulse counter. From that we could ascertain very accurately the velocity of the rotation of that shaft. Even though you can tell no difference, this is the plot of frequency or

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velocity of the control rod drive scram on 1/26/85. This is the simultaneous recording of both the encoded shaft pot readings and back EMF. We plotted the delta frequency. The peak delta frequency is approximately 1 out of an 80 mean hertz delta frequency. On an 80 hertz signal we felt we were tracking fairly closely, and in fact we think that is noise from the encoded shaft pot.

When we started taking back EMF data we noticed very distinctive variations from one rod to another. This is a refurbished rod, CRDSN-29. Let me go through this quickly. This is the same control rod after the refurbishment of the motor itself only. No other part of the drive was affected. There was a substantial improvement.

Next, the 200 assembly was refurbished. During that refurbishment a shim was placed improperly, I believe, on this one, the second stage of the mechanism, and you can notice the drastic impact that it has on the characteristics. Subsequently, refurbishment of that same assembly in fact restored it to identical to that, which was post-motor refurbishment.

The next series of transparencies I'll go through relatively quickly. They are a representation of where our software development is to date in viewing back EMF. This is a new concept, so we're still exploring and researching. The first thing we do, this is the software that was associated with the refurbishment program itself, did it pass. It recorded such things -- it ascertains, collates and brings forward items such as peak angular velocity, et cetera, so some of the areas or items which we were interested in we printed on the front sheet.

MR. WARD: You have some specs there or -- whether it passed or not?

MR. CRAUN: Yes, I'll get into that. That was for refurbishment. We've kind of enhanced our method of viewing -- some people call them the squiggles or whatever -- back EMF. Again you see the same two we saw earlier. What we have done, we're getting quite interested in the mean frequency during steady state. We're also interested in the mean voltage. We've defined a narrow band with there and here. We then take a close-up view of that and we can visualize the beat in the frequency. Now, the beat in the frequency is really interesting to us in that as the voltage peaks, your rod velocity will be on the decline. As your voltage is on the decline, your rod velocity will be at the peak. That oscillatory motion is unique to each rod and varies prior to and subsequent to refurbishment.

Another way to look at that oscillation or the beat is what we call our torque or torque or acceleration, excuse me, versus time plots. This is a representation of a full scram. I believe this is serial number 7. It is in core region 27. This was taken February 27. It is a full scram. We can take -- as I indicated, one of the criteria for the test is either to take full or partial scrams, 10-second scrams. Here you can see the hunt or the oscillatory motion because we were able to calculate the motion of the inertia of the rotating mechanisms and convert the change in frequency to acceleration, therefore torque imbalances, so we're looking at the stability of scram or the stability of scram velocity. The upper graph is just a blow up of the first 10 seconds.

Again, we repeat some of the -- there are some software errors I will point out. The actual scram time was not 10 seconds. It was 132. We do have a software error on this. We take from the first 10 seconds, though, we take and project what the scram time is. That way we can more accurately during the 10-second rod drop test predict scram time for that rod. As part of the criteria which I'll get to shortly, we felt that the performance of the control rod drive mechanism, the 200 assembly, specifically the gear train, the smoother the action and motion, the more probable it would scram. The more unstable, the more likely it would fail to scram.

We set -- one of the criteria is magnitude of the oscillation that you see there. As with any good engineer, give him a oscillatory signal and he will do a Fourier analysis. This is an interesting tool showing correlations that are unique. Of that scram we take 20 data sets out of the overall data file and do Fourier analysis and analyze them to smooth it up. We then wrote a program to scan downward to pick the peaks.

We also, as a result of being able to ascertain the frequency and speed of the motion of the rod, we were able to calculate such things as motor shaft rps, first stage shaft, second stage, third stage and drum rotational velocities. We were able to calculate actual gear mesh frequencies also. We noticed interesting correlations between the peaks and now the frequency of the gear train mechanism or component. The peak amplitude appeared at approximately half a hertz, which is reasonably close to the second stage shaft velocity or rotating velocity. You notice the 10 hertz is associated with the second to third stage gear meshing frequency. We start to see correlations of this develop.

There are about four more of these similar slides in your hand out. I'll only go through the second one. This is a partial scram profile. We are currently developing that software. You'll see in various points asterisks and numbers that don't make sense. That's because they are developing the software. This is a 10-second rod drop test, actually 9.4 seconds, and you see the application of the break. The velocity terminates. We see the stability of the frequency and also of the voltage, so we can plot our means and get our mean velocity which we use to project overall scram time. We also are able to or are developing the Fourier analysis from this oscillatory pattern. As with any Fourier analysis, if you in did you say an impulse load you will basically broaden all of the peaks. This is a very effective impulse load and if you look on your graphs you'll see the peaks are very broad. We're trying to, via the computer, eliminate an inclusion of that data.

Let me skip past the rest of the partial scram and get into our refurbishment criteria. Since back EMF is unique, it is a characteristic, a fingerprint of a mechanism, one would not expect them to be identical and they are not. We therefore went to a statistical criteria to ascertain the effectiveness of the refurbishment program.

This is supposed to represent a plot of all of the data sets we had at the time. Prior to getting very far into the program it was decided it would be best if PSC had a development criteria, so before we finished we developed the criteria. We excluded in the population outside of the box any rod that had a characteristic or demonstrated the unwillingness to scram, so that only those control rod drive mechanisms that were showing a consistent reliable willingness to scram were included in the box as the acceptance criteria plus a little margin thrown in, so that's how we developed our criteria for refurbishment. To give you a better flavor for or impression of what the refurbishment program did for us, this represents all the control rod drives in core and their willingness or -- and how they compare to the criteria. The solid horizontal line is the acceptance criteria. I converted it to radians pei seconds squared. These are the control rod serial numbers at the bottom. The willingness of those rods to come to speed, the mean was below the acceptance criteria.

MR. SIESS: The blanks are the ones that failed?

MR. CRAUN: They were not involved in the refurbishment or are still disassembled, the six spares -- pardon me, seven spares.

MR. SIESS: Which are the rods that didn't go in?

MR. CRAUN: By the time we had back EMF developed, we had already gone through the first round. I believe we have one of them and that was -- serial number 44 is the only prerefurbishment failure rod of June 23. Remembering that slide, if you will, notice the drastic improvement. We've now elevated substantially the mean performance characteristics of the control rod drive mechanisms.

Again, the criteria, now the mean is substantially higher. Now this criteria that I'm referring to was a refurbishment criteria. It is very essential for us to continue acquiring data to asses the change in performance characteristics associated with these control rods as with increased power levels, increased temperature, et cetera, so we're very interested in monitoring and acquiring additional data.

Even though I like back EMF, it does have its strengths and its weaknesses. The limitations of back EMF are first -- it is a little difficult to relate this -- since there are two wave forms generated per rotation of the motor, we are limited in the number of frequencies that we can calculate. As a result of that, we are limited in the frequency at which we can look. We're limited currently to approximately 40 hertz. We would like to look at higher frequencies because we do have gear mesh frequencies and rotational frequencies in the higher regime.

The next is that we're trying to predict the static performance of a mechanism by viewing its dynamic performance characteristics. As most of you remember, the static coefficients of friction are typically higher than dynamic, so we're looking at a reduced coefficient to predict a higher come efficient value.

The third is that we're trying to ascertain the efficiency of a gearing mechanism as seen through the eyes of a generator, so we have to view through the generator to predict the gear train performance. That's a secondary measurement. We would obviously like to have a primary measurement. It would be more effective.

As you can see, we can make voltage tracings; the computer is very willing to do that. We can look at wave form diagnostics. We can look carefully at individual wave forms. If we see an abnormal oscillation, we can investigate that by focusing in on that. If properly controlled, we have an improved retrievability of our data sets. Back EMF views both mechanical and electrical until back EMF or regenerative voltage braking comes into play. The only thing limiting the acceleration of the control rod is the efficiency and the internal friction of the mechanism itself. Lastly, it will work in core, at power, on any withdrawn rod.

MR. SIESS: What do you do, release the brake and let it drop for 10 seconds?

MR. CRAUN: Approximately.

MR. SIESS: Why the question of static versus dynamic, then?

MR. CRAUN: Back EMF is recording the voltage after it has gone into motion.

MR. SIESS: When you release the brake that test is static, isn't it? If it doesn't move there's something wrong?

MR. CRAUN: Yes. We're trying to mitigate the returns of the event of June 29, to use a dynamic characteristic to predict a static characteristics. Every time we test them it demonstrates the static, right.

MR. SIESS: When it doesn't drop when you release the brake you know you have a problem. The six rods didn't go in, they didn't say move at all?

MR. CRAUN: Two of them did. Two moved a short distance and then stopped. I believe is what the record shows.

MR. SIESS: The ones that didn't move --

MR. CRAUN: They didn't ever.

MR. SIESS: And you don't know why?

MR. CRAUN: As Frank indicated, it could be a combination of a variety of things.

MR. SIESS: Enough static friction in the system?

MR. CRAUN: As demonstrated, the willingness of the rods prior to refurbishment was substantially lower than the willingness of the rods to come to speed post-refurbishment, so I would consider it a lack of maintenance over a prolonged period of time. As indicated as one of the strengths or advantages of back EMF, we can trend the performance of the control rod drive. I selected just -- no basic reason -- a time period from June of '85 to February of '86. We then pulled all the front end acceleration data and plotted that to show the overall performance characteristics of all 37 rods in the core. With any measuring device that is trying to measure the stability and efficiency of a gear train, not all will be equal. We notice some lower performers and som higher performers. That would be to be expected.

MR. SIESS: You test every drive weekly?

MR. CRAUN: Every one that is partially or fully withdrawn, with the exception of, I believe, the regular rod. I don't believe they let that go through.

MR. SIESS: Going back to the four or five that didn't move at all, have you thought of my mechanism that would have kept those drives from moving and yet would have shown no dynamic discrepancies in weekly tests prior to that time?

MR. CRAUN: This dynamic testing program was developed subsequent to that, so there was not a dynamic testing program of this complexity prior to -- during the refurbishment program, to try to answer your question, we were able to detect shim mislocations. Abnormalities that took place during the refurbishment program, we were able to spot those on back EMF. We were not always able to state exactly where the abnormality should be located. On several occasions we were able to do that. Have I thought of a characteristic that would not show up at all dynamically, no.

MR. SIESS: How long had it been since those rods had been moved or those five that didn't move?

MR. CRAUN: Hours.

MR. SIESS: It just seems if you tested them a week earlier they would have shown something. That that didn't happen in a hour.

MR. NOVACHEK: They may well have. Previously we were testing only the scram times, the drop rate, like I indicated before. We were not taking measurements of wattage or back EMF or anything like that at the time, so I think that based on what we saw in the drives, that those sorts of things would have been picked up by a test similar to this; at least some indication through trend analysis that there was a degradation occurring would have shown up.

MR. SIESS: That what I'm getting at. I could visualize some piece that brakes, but that would have to be random.

MR. CRAUN: If we go to this slide, this is a prerefurbished control rod mechanism. I did not bring overhead transparencies of the Fourier or any subsequent analysis of this rod. It would trigger any criteria you would want to. This rod was not one of the rods that failed to scram on June 23. The number 4445 we have a data set on -- was substantially worse than the characteristics of this. Post-refurbishment that's a very smooth, even voltage and velocity. As you can see here, this rod is wanting to stall in these regions. The velocity is dipping substantially. On number 44 that dip was drastic. As it was still wanting to move and willing to move, its velocity characteristics were very noticeable.

MR. NOVACHEK: If we saw something like this at power -- we're still collecting data to determine -- it may be the temperature and flow through the region and all that sort of thing has an effect on the back-EMF traces, so we're still in an experimental stage and a research stage.

MR. WAREMBOURG: We did conclude as a result of the test program that the most sensitive thing that's probably causing failure to scram is the first stage gearing and the bearings associated with the shim. And if we had to draw a conclusion as to why it is that the rods were hanging up, we believe that they hung up primarily because of the bearings in the shim motors.

MR. SIESS: If it is a progressive deterioration you ought to be able to detect it. You would have a fairly high degree of confidence. If it is a sudden deterioration, then you have to worry about whether it could happen to enough rods. If a gear breaks, it probably won't move.

MR. WAREMBOURG: We think with back EMF as it is, you can start seeing the deterioration. If it is the motor bearings that's the main culprit, we believe back EMF will detect deterioration.

MR. CRAUN: The last part of the presentation will address where we're heading with back EMF. It is not part of this slide, but an obvious area is not really an investigation it is an acquisition of a data base. Since this is a unique program, we're acquiring as much data as we can get our hands on to further understand what back EMF is trying to indicate to us. The research and development on back EMF will be in four areas. We'll do a variable weight drop test. We'll replace the rods on the absorber strings on one of the mechanisms and vary the weight to assess that impact on willingness to stall or failure to scram. Try to get more data sets in the vicinity of failures to scram.

The next is a torque imbalance test. What we intend to do is induce an oscillatory drag to the mechanism and see if in fact we can see that on the generator end.

The third would be to monitor not only a single phase but all three phases to allow us to increase the number of frequency calculations per rotation of the motor. That will let us look at higher frequencies than the Fouriers allowed us to look at at this time.

The fourth and the first to be performed will be the moment verification or validation test. We will be installing a Hemelstein between the first stage pin and the first stage gear. That's a monitoring device. As with any shaft, you have a hunting or wobble in the shaft. It measures that wobble. That wobble is exactly what back EMF is measuring, so we'll have a second dynamic validation of back EMF. Are there any questions?

MR. HEITNER: Can staff make a comment? I think this is a very good presentation. A couple of things that perhaps didn't come out clearly or I didn't catch them, first of all, the question of whether there was pump flow or not to the control rod drives, at the time of the scram, subsequently some long time after the failure, PSC did discover and separately report to us the fact that supply lines to the control rod drive penetrations with helium flow would normally come through were blocked.

At the time of this scram, there was no -- plus they fixed that problem. At the time of the scram there was no way of determining whether any individual control rod drive penetration was getting pump flow, but they have now installed individual flow meters to each control rod drive penetration to allow them to establish whether they are getting flow.

I believe there's also instrumentation there that determines whether there's been an accumulation of moisture in that incoming flow. There's knockout pots and alarms so you can tell whether you have been feeding it wet helium instead of dry helium. Now that they can tell whether they are getting flow and if there's an interruption of flow to one of the control rod drive mechanisms, they can take appropriate corrective action.

The second thing that's important is -- and I think they discussed this extensively -- is finding out what makes a good rod. Obviously, initial acceleration rate if that deteriorates sharply, it is an indication that the rod's performance is deteriorating. It is low enough you have to assume that that rod will fail to scram. I was curious about the data on serial number 14 where the date and time showed it degraded and got better again. I don't know what to make of that right now.

MR. CRAUN: Is that a question?

MR. SIESS: I think you're talking about these two figures? I noticed a number of cases where the post was lower than the pre. I just assumed that's within the range of variations.

MR. CRAUN: There were a couple where the post-refurbished was below the prerefurbished.

MR. SIESS: What's your ability to replicate?

MR. CRAUN: From one scram to another scram, the replication, as I indicated with varying rod withdrawal percentages, it does come into the theoretical predicted value very closely.

MR. SIESS: No, that's not what I meant. Your 10-second drop test gives you a rads per second. If you

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perform that test on the same drive 10 times, what's your standard deviation?

MR. CRAUN: That is a question I cannot answer. I can answer, but I don't have the data with me. The variation is minor. It is not zero.

MR. SIESS: Is it enough to account for the pre and post differences?

MR. CRAUN: Not at all. Not at all.

MR. HEITNER: The second thing I would think is very important is the fact that they now have the temperature instrumentation on all the control rod drive mechanisms as opposed to just a few. Again, at the time of the failure, there was no way of determining whether the failed control rod drives were just too hot or not. Now we have definite temperature data that's being continuously monitored, and if the rods go above the temperature which they consider them qualified for, they have to consider that rod inoperable and they are only allowed to have one inoperable rod. Plus they are also attempting to requalify the rods for higher temperatures.

The third area of importance is the fact that the instrumentation for the rod drives, which they acknowledge is deficient, needs to be upgraded and they are still carrying out system studies to do this. I think -- I guess it is important that position indication instrumentation will also be viewed as instrumentation that could be potentially used for monitoring control rod drive performance during the short drop tests so that you can get more accurate data on the rod's performance in the dynamic sense. That's probably the best indication that you have that a potential failure is coming along. I think we're only about halfway through resolving all these problems.

There are a lot of possibilities we're coming up with, but the fact that you are monitoring the pump flow temperature and also the performance of the control rod, I think we'll have a greater assurance that they will work in the future and any potential failures will be anticipated.

MR. SIESS: What you're saying is the back EMF monitoring is a corrective action for what I think was said earlier was simply a lack of maintenance; things got worse. The other things you mentioned, the pump flow and temperature, the possible causes have also been fixed. The moisture, the temperature, the helium flow and the maintenance problem, bearing problem, you say those have all been fixed?

MR. CRAUN: Yes.

MR. SIESS: What about position monitoring?

MR. CRAUN: There's been no modifications to the position monitoring system on the rods to date.

MR. SIESS: You do it by rotation of the --

MR. CRAUN: There is a pot that is hooked to a camming mechanism that runs off the drum, so it is a 10-turn pot, you then monitor the number of turns in the pot and that's related back to the position.

MR. SIESS: In the 10-second drop test, in effect what you do is count the turns of the motor?

MR. CRAUN: Actually, during the drop test they just release the break for approximately equal to or less than 10 seconds and everything is recorded.

MR. SIESS: Don't your measurements essentially count the rotations?

MR. CRAUN: Yes, they count the gear off of the drum or the hub.

MR. SIESS: And they go sideways or --

MR. CRAUN: Every two sideways is a rotation of the motor.

MR. WAREMBOURG: Some of the problems with the instrumentation on the pot, if you scram the rod and it goes in at a faster velocity, sometimes it tends to wind back up on the drum, but when it does that, it shears the shaft on this pot, so then the indication of that pot becomes inoperable and we no longer have an indication, so we are looking at in the future putting in a higher-ratio turn pot that will allow us to take some backlash. We're looking at some other improvements in the instrumentation, but are somewhat limited there in terms of the control rod drive. With motor wattage tests you can also, as a secondary thing, tell whether the rod is fully inserted or not.

MR. SIESS: I'll keep that in mind. Thank you. I think this is a good time for a break.

MR. MC BRIDE: I'm Milt McBride. My subject today is the reserve shutdown of the material changeout. If I don't speak loud enough, I have a head cold, so don't yell at me.

My presentation is basically based on our report made to the Commission in January 1985. It was transmitted to the NRC in January 28, 1985 letter. The intent of the discussion will be to provide a general discussion on reserve shutdown hopper system, and I'll be brief about that, because some of the other people have already presented quite a bit of that information. I'll discuss the problem for a little bit and then the corrective actions taken to resolve the problem.

The first figure you'll see is one of a little different view of the control rod drive. I'll call your attention to the hopper, a little different view with the filler plug, the cylindrical hopper which contains the shutdown balls. In your packet you'll see a blowup of the lines here along with the graphite rupture disk and a guide tube that allows the reserve shutdown material to fall into the core. Our particular design contains two different sizes of reserve shutdown material. One size which is 7/16ths inch in diameter and contains 20 percent natural boron is in regions 1 through 19 of the core.

The other region can have a 9/16ths inch diameter ball which is 40 percent natural boron. The material is held in the hopper by the graphite disk which Frank talked about earlier. The disk is designed to rupture at pressures less than 300 psi D: The reason for the two different weights of boron is that the lighter boron was chosen to enhance the stability of the material in the hottest regions during reserve shutdown. Stability, by the way, what I mean by that is structural integrity of the graphite skeleton in the event of a permanent loss of LOFC at the elevated temperatures.

In your packet you'll find -- I want to go back to figure 6 to provide some completeness. Figure 6 is nothing more than a blowup of the rod guide tubes and reserve shutdown guide tube to illustrate how the orifice drive and the guide tube interfaces with the upper reflector block, and this gives you more of a blowup view of how it interfaces at the refueling region. Figure 7 in your packet I want to refer to again in summary, because Frank did give you a quick overview of this also.

The only thing I want to call to your attention is the fact that the reserve shutdown system is designed with two different sub 14s, one containing seven subsystems and the other containing 30 regions. There's no significance other than the fact the seven is designed to be initially fired in the event that we had to compensate for the report's reactivity accident. The other 30 are designed to be used only if the regular means of reactor shutdown are ineffective. With that, let's go into that, give you a basic overview of how the system is designed in the reactor core.

I would like to discuss now the problem. Subsequent to the June 23, 1983 moisture ingress, we at PSC committed to do a hopper test on two reserve shutdown, hoppers as opposed to what at that time our tech specs required, which was one. We committed to do one high and one low boron concentration hopper. The test consists, as Frank showed you, although we've redesigned it and it is more enhanced than originally, of pressurizing the hopper, allow the diaphragm to rupture, capping the balls in the container and weighing the container to make sure we have got all the material out of the hopper.

As a result of those tests, the first one we tested was one low, which is the 20-weight boron from an inner region, and that tested fine. All the 80 pounds, plus or minus 8, released from the hopper, the diaphragm ruptured properly. The second test was whether the high, 40-weight boron from the outer region was not successful. Only 40 pounds of the potential 80 was released from the hopper upon rupture of the diaphragm and was retained in the container. Subsequent examination outside the core area in the hot cell revealed that in the upper region of the hopper around the filler cap area, the material was fine. It was loose, it would have released, but in the middle of the hopper, the material had agglomerated and that is figure 2, which is a slide that I had made of some of the photographs of the material as it came out of that particular rod. And as you can see, there are a lot of crystals that are formed in the blowup here on the individual balls and this is an agglomerated -- sort of what you would call a grapevine sort of looking mass of agglomerated balls out of that particular drive.

MR. SIESS: Do those balls have those ribs on them?

MR. MC BRIDE: Yes, they do. It has to do with the design and the number of diameters and so forth that, a series of balls can in theory fall down a cylindrical hopper without bridging themselves, by their natural fall along with the number of diameters -- there's a little equation to calculate that, but that's why the ridge. It doesn't have to be very pronounced. This particular size of ridge is more due to the manufacturing process, which at that time was, these balls are manufactured by UCC, Union Carbide

Corporation. Further analysis in two different independent labs revealed this material that you see here is anhydrous boric acid crystal. We do expect to get some boric acid crystal formation in the hoppers if there is moisture or water vapor in the hopper. The reason for that is because this particular series of balls was manufactured to a purchase specification that would allow less than 1 percent leachable boron oxide, which in the presence of water forms the boric acid crystal. You would expect to see some, albeit we certainly did not expect to see what you see here. Going back to the figure one for a quick second, the reason the balls agglomerated in the center section as opposed to either end is due to the fact that when moisture is ingressed into this area, the temperature at this point down low here is about 700 degrees Fahrenheit. The temperature in the mid-range goes down to a range of about 500 to 300 degrees Fahrenheit in this range and, as a result, you see a volatilization of the boric acid down low which then condenses in the center region, hence the agglomeration.

MR. WARD: Why doesn't it agglomerate at the top?

MR. MC BRIDE: You're cooler there than you are down low. Basically there are potentially three ways of getting water into the hopper area themselves. The first way is by water vapor in the primary coolant diffusing through the rupture disk itself which is in contact with the primary coolant on the CRDOA line, a breathing effect on the pump line due to changes in the primary system pressure, pumping up and pumping down. The most likely scenario, by the way, at this time, during our design, was either breathing or the water flow from purified helium venter. We've done a number of things to correct that and I'll talk about that in more detail later.

MR. SIESS: At the upper left section, where is that on the right-hand sketch?

MR. MC BRIDE: Right at the bottom. You can barely see it. Any questions on the problem itself? Let's discuss corrective actions we've taken since that time. The first thing and the most important thing in my view was the fact that we made a decision to replace the Union Carbide material with material manufactured by ART, Advanced Refractory Techniques out of New York. The UCC material contained a higher leachable boric oxide content, so we wanted to reduce to the degree possible the amount of leachable boron oxide. As you can see, to give you an example on the 20-weight and 40-weight UCC material versus the ART material, we were able to reduce the amount of leachable boron in the 20-weight by a factor of 20 and on the 40-weight by a factor of about 10, so I think that, in my view, is probably one of the more important factors in reducing --

MR. WARD: What are those numbers? I didn't understand.

MR. MC BRIDE: These are percent. Percent of total, percent of leachable boron. The spec requires you to have less than one percent of leachable boron. We're coming in at about .8. But observe the new numbers on the new material coming out of the ART. Does that answer your question?

MR. WARD: Yes.

MR. MC BRIDE: The second corrective action we've taken, again, referred to earlier by Frank Novachek, was to increase our surveillance program now. The interim tech spec requires us every refueling cycle to do a surveillance test on one high hopper and one low hopper. Go in, blow the diaphragm, allow the balls, material to fall into the container, do a visual and a chemical analysis of that material.

MR. SIESS: Did this agglomeration occur in all the hoppers?

MR. MC BRIDE: No, not all of them. For one thing, the inner hoppers I doubt it did, simply because of lower boron.

MR. SIESS: Do you know?

MR. NOVACHEK: No. Because of the design of the air vacuum system, to quote Frank, it was rough. It was very strong, the process was, and the decision was made to take all the material out and dispose of it; therefore, the air vacuum cleaner was quite strong and would virtually have collapsed -- that agglomeration if there was any. As I say, we were going to let the material fall out. We didn't want to destroy the rupture disk assemblies. We would have increased personnel exposure significantly.

MR. SIESS: I asked whether this contamination had occurred in all the drives.

MR. NOVACHEK: Not all but a significant number, yes.

MR. SIESS: Your previous surveillance program was what?

MR. NOVACHEK: It involved blowing the hopper on a single reserve shutdown hopper once per refueling cycle.

MR. WALKER: We had only done two. This is the third refueling.

MR. SIESS: This had been developing over quite a period of time.

MR. MC BRIDE: 10 years.

MR. SIESS: In the previous surveillance test, was there any looking at the stuff that came out, or just weigh it?

MR. NOVACHEK: We did look at the material, yes.

MR. SIESS: In those tests you hadn't seen any formations like this?

MR. NOVACHEK: We had an event in 1975 where we saw this type of behavior following a moisture ingress to the reactor vessel of approximately 4000 gallons of water. And we did observe it at that time.

MR. MC BRIDE: In that case it was the same thing. It was the anhydrous boric acid, but two conditions were different, now, as opposed to the original. One was the fact that our power history was very, very low at that point and the massive water ingress and the amount of time that water was in the vessel was quite a bit different. We did see some boric acid buildup, albeit no agglomeration that we saw in this case.

Okay, again, another, in our view, major improvement is that we replaced all the helium flow instrumentation, both the headers and the individual subheaders -- instrumentation with more accurate, more reliable instrumentation. We also added, again, knockout pots with site glasses and high-level water alarms to the pump lines and also to the steam generator and helium circulator interspaces. That's figure 5. I have a drawing of that system design as to how that was done. It is figure 5.

Figure 4 in your packet gives a view of what earlier was referred to, which is, coming off of the supply for the purified helium header, you'll find a knockout pot with a level indicator, a level switch and a moisture element which -- the alarm is in the control room, by the way -- and a new flow element to each rod. There's a major improvement in terms of information to the operator as to what's occurring in the control rod drives. Last, a matter referred to earlier by Don was the Fort St. Vrain Improvement Committee whose function was to reduce moisture ingress-related events.

As Don stated earlier, the committee has since been expanded to address a lot of other issues besides moisture ingress. That's about the summary of what we've done with the reserve shut down material.

MR. SIESS: Do you reduce the two quantities of the materials that caused this and more frequent surveillance?

MR. MC BRIDE: Yes, and more increased monitoring. Any other questions?

MR. SIESS: Thank you. We're now up to tomorrow. I'm proposing that we make some changes in the order of presentation. They will be -- we will move item C and item F to the bottom of the list and will take up items B, D, G, H in that order. The two items we're removing are ones of greatest interest to me, but they are also matters that have been followed very closely from the written material, and the item on masonry block walls is not at all peculiar to HTGRs and I may even want to delete that one completely.

Now we'll go to equipment qualifications.

MR. NIEHOFF: I'm Mike Niehoff, the nuclear design manager. Mr. Holmes talked to you earlier about some of the history and licensing aspects of EQ. The purpose of this talk will be to cover some of the technical details in our current plans and some of the details of our steam line rupture detection and isolation system. Public Service Company is continuing to develop a program to meet the requirements of 10CFR50.49. We still have a lot of procedure revisions that are ongoing. We have a ways to go. We've developed a controlled master equipment list that has been generated in accordance with b1, b2 and b3 of the rule that says we've considered the items to mitigate the accident, shut down the reactor, keep it shut down, maintain reactor pressure boundary and recover and restore forced circulation cooling.

We considered the impact of failures of nonsafety-related equipment on the safety-related equipment and we've considered the aspects of post-accident monitoring equipment. Fort St. Vrain is a DOR guideline plant. Basically that means we're covered partially by paragraph K of the rule which says we can use analysis in terms of the Uranus techniques to prepare some of our binders and equipment qualification. We're also preparing other binders on equipment installed after February of '83 in accordance with the category 1 requirements of NUREG 588. Our environmental qualification binders address various parameters, in terms of temperature and pressure. We calculate temperature using a couple different codes via General Atomic, the flash blowdown code and the temperature code. These temperatures are limited by SLRDIS and I'll get in more details of that in a minute. In terms of pressure aspects the building, both by various design features and in terms of blowup packages and it's open nature in terms of windows and things of that nature, we don't have a long term pressure transient. It is very short duration and over very quickly.

Similarly, in terms of humidity, again, with the open nature of the building, the humidity transient is relatively short-term, a few hours. Chemical effects, we're not using any safe shutdown containment spray systems or anything that gets us into that arena. In terms of radiation, would not expect to see any radiation directly resulting from high-energy line break unless you compound other accidents with it.

Typical threshold for equipment qualification is on the order of 10 to the 4th rads. In the case of a design basis accident number 1, we would see a 180-day total integrated dose of around 400 rads or even compounding some of those accidents we're well below the threshold. In terms of aging, the equipment in the plant prior to February of '83 we're using some of the Uranus techniques in calculating the aging of the materials. Equipment we've installed since February of '83, we're going through the full category 1 test program. In terms of submergence, the worst case submergence event was a rupture of our condensate system, where we assumed both storage tanks were full and drained our entire inventory. In terms of the reactor building, the sump capacity is some 334 gallons, so it was no problem. In the turbine building, the sump is not that large and we would see an elevation of around 6-1/2 inches on the floor; again, with the open nature of the building and ability to get the water out the doors and things it did not present a problem. We have no equipment to monitor that low to the ground.

MR. SIESS: Had you previously looked at flooding from other sources?

MR. NIEHOFF: From other external sources?

MR. HOLMES: I did consider flooding from several different sources, external and internal.

MR. NIEHOFF: In terms of margin, as Mike indicated earlier, some of the original General Atomic tests were 30 minutes in duration and we're now supplementing them with other industry tests and other industry materials data to make sure we do have adequate qualification margin.

MR. SIESS: I think somebody said earlier that all of the equipment that is of concern is electrical equipment.

MR. NIEHOFF: That's correct.

MR. SIESS: Does that include cabling?

MR. NIEHOFF: That's correct. We do have cables in our program. Cables that are in the program are those involved in any of the systems mentioned in this b1, b2 and b3. It would include cables; we have situations where we have a pump in a mild environment and it may go from the control room and traverse the harsh environment and go to the equipment item in a mild environment so you pick up more cable items in essence.

MR. WAREMBOURG: The cable problem is the one we're having the hard spot with now. We're able to identify all of the cables by the materials that are in the cables, but we cannot identify the manufacturers of all those cables, so we are proposing to the NRC to qualify those cables on the basis of their materials, and that those materials have been qualified by other means; and we just don't have agreement right now between us and the NRC as to what's going to happen to those cables. The problem with that is compounded in that we cannot put our hands on any cable and say this came from Iron Cable or Zero Cable. So we run into the problem of not accepting this on a material basis; it is an all or none situation, in other words.

MR. SIESS: If one fails, you have to assume --

MR. WAREMBOURG: We've got a good indication of most of the cables in the plant and the manufacturer of those, but we have a block of cables that we purchased from Iron Cable that we cannot identify the manufacturer. They were a wholesale supplier. Nor can we go out in the field and identify those Iron cables. We're in a situation now --

MR. SIESS: You don't know where those are in the plant?

MR. WAREMBOURG: We don't know the difference between an Iron Cable and a Zero Cable. We can't go into a testing or sample program because we physically cannot separate those cables in the field. So if our position of material qualifications is not accepted, it is a 100 percent situation, not a 10 percent situation.

MR. WARD: You say you can identify the materials, but the manufacture of cable is such a black art, as I understand it, it is hard to predict the performance from some data on the materials.

MR. WAREMBOURG: Sandia did most of the qualification work based on materials, without reference particularly to manufacturer. We would like to do the same thing.

MR. SIESS: Refresh my memory. I know there's been an awful lot done on fire resistance of cables, but this is all just resistance to temperature, I guess that would be the main item, wouldn't it here?

MR. WAREMBOURG: Temperature and aging.

MR. WARD: At issue is whether they lose their insulation properties in this sort of steambath transient that you have calculated; right?

MR. WAREMBOURG: Yes.

MR. NIEHOFF: We did put a lot of representative samplings of the cables in the plant through the test and they peeked at about 650 degrees and lasted for 30 minutes. We've done that and as Don indicated, we've researched some of the Sandia tests and all of our cable is certed to the various IPCA standards and we do know the materials and the thickness of the insulation and the jackets, and based on that, and going back to vendor test reports from the same vintage of the time of cable construction, we feel that we've got a basis for qualifying the cables.

MR. SIESS: I see the qualification as to those temperature profiles that reach 360 degrees for a couple of minutes, and that profile has been accepted by Staff, has it?

MR. NIEHOFF: It is under evaluation right now.

MR. SIESS: Has Sandia ever had any failures?

MR. NIEHOFF: Most of the failures I'm aware of were as a result of some of the high radiation environment and different things. I'm not sure that I'm aware of any that failed because of these types of temperatures.

MR. WARD: This issue of whether the properties of a cable can be really identified, I guess I've had the idea that the filler materials in the insulation and even the color in materials can affect the properties of the installation, but that may have been primarily the fire resistance properties rather than what we're talking about here. Are you familiar at all with that?

MR. NIEHOFF: I guess I'm not familiar with that being an issue. From our perspective, we have tried to look at just raw temperature values associated with the various materials and compare those to what we would expect to see in sacrificing the jacket on our cable and getting down to the individual conductors and really I believe it was our PBC cable was the worst-case actor.

MR. WARD: What's the Staff's complaint with the program; or is it too early to say whether you even have a complaint?

MR. HEITNER: I think the standard procedure is to know what the cable is in terms of what the manufacturer has done and how the qualification was bought on that specific cable from that specific manufacturer. A similar problem has been encountered at other utilities. Sequoyah is having the same problem. The second approach is to take out samples of the cable from the plant and send those off to be tested and qualified and to elect that way, which, we've had some difficulties doing that, because of, in fact, they are not sure within cable groups, let's say, a five-conductor cable of various properties, that even those cables came from the same manufacturer. There would still be some unknown about that, even if you did a test on one piece, that you wouldn't be sure someplace else it was a piece with a different property.

MR. SIESS: This must have come up in connection with some of the plants in the SEP. I'm sure they don't know any better than Fort St. Vrain where their cable came from or which cable is where. How was it resolved on the SEP plants?

MR. HEITNER: I don't know the answer to that. That's a good question.

MR. SIESS: On the SEP plants there were a number of things resolved partly based on probabilities, PRA type stuff, and partly based on judgments, I would say, together with all the data you could get. They were plants that were not built according to present criteria. There was no reason to expect them to meet them. You didn't qualify as an SEP -- what.

MR. WAREMBOURG: What is that?

MR. SIESS: Systematic evaluation program that picked up the early plants. It was the oldest five and then some plants that didn't have an FTOL, full-term operating license. This included Big Rock, Yankee Rowe -- Dresden 1 dropped out but Dresden 2 was in it. Dresden 3 was in it -- 2 was, I'm sorry. San Onofre 1, Millstone 1, Indian Point 1 would have been in it but it is shut down. Pallisades, which probably started construction about the same time you did. But they were all water reactors, more or less.

MR. WARD: It seems to me there would be good reason for the Staff to, you know, look at the same sort of arguments that were made in the SEP reviews.

MR. SIESS: And they were not all small. One of them has produced more power than any other reactor in the world, Vermont Yankee.

MR. WALKER: We can check with those plants.

MR. SIESS: Call Chris Brown. He'll know offhand. I'm surprised that Sequoyah is in that category. It was quite a few years later.

MR. WARD: They have arrived at what might be a similar situation, possibly for otl reasons. I don't know if it is in that category.

MR. SIESS: I was down at Sequoyah when they hadn't pulled the cable yet. Cable was the last thing they put in it, I think.

MR. NIEHOFF: Okay, we discussed the SLRDIS system is an important part of our qualification program, to provide continuous monitoring of area temperatures in both reactor and turbine buildings, minimize building environmental conditions following the steam line rupture, protect functional integrity of EQ shutdown equipment, allows the use of industry qualified equipment, enhance reentry into plant areas. This item is no longer as critical since we've proposed to relocate various valves and provide new valves in mild environments to allow us to restore forced circulation to mild environments.

As far as the system scope, there are four temperature sensors in each building per each SLRDIS panel. These are 200 feet in length and they are located in about mid-wall at the extremities of the building. The system is based on a microprocessor logic arrangement. It interfaces with our plant protective system into the circulator trip circuitry. This gives us a trip of all four circulators and the associated protective actions and also a two loop trouble trip in the associated trouble actions and a reactor scram, and gives valve closure to isolate the break.

This is a somewhat simplified flow diagram of the plant and, walking through the flow path, starting at the feed pumps, going through the steam generators, coming out as main steam, going over to high pressure sections of the turbine generator, out of that is cold reheat providing the motive force for the helium circulators, emerges and back to the immediate and low pressure sections of the turbine. These valves that are colored pink here represent a good number of the valves that are closed by the SLRDIS system.

Earlier this morning I think there were some discussions about the original program and single failure criteria, but consider any valve as a potential for a single failure, and that provided valves to account for that, and in other cases, we blew down the entire inventory of whatever the section of piping would be. That's the profile that resulted.

MR. WARD: You said the analysis does assume even single mechanical failures?

MR. NIEHOFF: What I'm saying is in the original program, basically it concluded if you had two electrical signals going to a single valve, it was failure-proof. We've gone beyond that in this program, said we could even fail that valve, and went to the next step to create these profiles. There was some argument about whether that meant it was really single failure-proof or not because an automatic valve was an element and even though the electrical part was single failure-proof, was the valve in total single failure-proof.

MR. SIESS: Where do you postulate the break?

MR. NIEHOFF: Basically anywhere. We've gone through any number of --

MR. SIESS: Has to be at the reactor building. Which is the line you're talking about breaking?

MR. NIEHOFF: I think that will become clear as I get to the profiles. There may be a dozen or two scenarios that we've gone through in each building. Any line on here is subject to a potential break.

MR. SIESS: You have equipment in both buildings that has to be qualified?

MR. NIEHOFF: That's right. We developed profiles for both buildings. More of the details on SLRDIS was designed to meet single failure criteria for production systems. Portions of the systems that are in the harsh environment are being qualified for that environment. The system is seismically qualified. It utilizes a two-panel concept to reduce the impact of a spurious trip --

MR. WARD: What is the SSE?

MR. GAHM: .1 G.

MR. NIEHOFF: Uses a two out of four logic in the sensing circuits. Redundant microprocessors, log in and valve actuation. Cable to function without off site power. Set off to alarm at 135 degrees F analysis value. Trips at [illegible]5 degrees F per minute.

Temperature profiles -- after our meetings with the Staff, we reached a mutual agreement to consider a spectrum of break sizes in our program. We've done that. The larger breaks are automatically terminated by the SLRDIS system and result in peak temperatures of 360 degrees F in the turbine building and 3771 in the reactor building. There are smaller breaks that do require manual operator action to terminate these, provide temperatures in the range of 130 to 134 degrees about one hour either after termination or after initiation of the break, depending on which scenario you look at. Here is a typical composite profile in the turbine building. As I indicated earlier, this is a sample of some of the scenarios. Again, the profiles on this end are the ones that are automatically detected and isolated in the SLRDIS. Some on this end are manually terminated after we receive the high temperature alarm.

MR. SIESS: That's 150, 160 degrees, that's ambient temperature, the temperature of the air?

MR. NIEHOFF: Bulk environmental temperature of the building.

MR. SIESS: Those are drawn out to about 1 hour and 40 minutes, 100 minutes.

MR. NIEHOFF: They continue down until you reach whatever the ambient temperature ends up either outside or plant condi ons.

MR. WARD: Recently a couple of fossil plants have had big steam line failures. Mohave -- is there any information from those on what sort of interior building temperature profiles occurred or whether there was any equipment that was damaged?

MR. NIEHOFF: The information has been somewhat limited that we get from some of these people, but what we have learned, I guess, is that the temperature transient doesn't appear to be as severe in terms of its longevity as some of the calculations would show. They were able to get back into the plants relatively soon, and in terms of equipment damage, obviously the items that were in the path of the blowdown were really in bad shape and destroyed in many cases.

MR. SIESS: By heat or pressure?

MR. NIEHOFF: Probably both.

MR. WAREMBOURG: I talked with the fellow from Mohave at some length. They indicated that they didn't have any indication as to what temperature they actually saw. Their plant is very similar to ours. They have a hot reheat line going through a mezzanine level and that's exactly where it broke. They opened up and just immediately dumped everything and they just blew everything down from the boiler all the way down. They have a lot more inventory than what we've got.

Now, it did get very hot. The individual that I talked to indicated even some of the gridding had curled on the floor, and he said that their boiler feed pumps, in effect air compressors, are located below where ours are. As a result of their steam line break, the control room was filled full of steam and they were back in the area in lifesaving situations within 15 minutes, with no protective clothing on, and the biggest problem that they experienced was that when the thing blew up, it pulverized all the inside lanes and they couldn't see, nor could they breathe well, so they had to go in with paper air masks, so the biggest problems they had to deal with was the atomized insulation in the air. The control room filled with steam. They experienced no resulting failures of their instrumentation. The plant came down, shut down, a turbine trip, no operator action taken. All the instrumentation in the control room functioned. They took a turbine trip, they came down. All this black magic we're going through didn't come about at Mohave.

MR. SIESS: Of course you have a lot more things that can fail.

MR. WAREMBOURG: Yes, but they didn't have any pump failures. The local instrumentation right around the steam line obviously was wiped out completely from direct impingement.

MR. SIESS: Any cabling in the steam tunnel?

MR. WAREMBOURG: I don't specifically recall talking to him about cable. That was one area I didn't discuss with him, but in general I got the impression from him that from a temperature viewpoint it really wasn't that serious.

MR. SIESS: Have you looked at Monroe?

MR. WAREMBOURG: We have not yet. Mohave's information was still limited in that they still had lawsuits and legal actions and those kinds of things and they were not willing to give us anything in writing but --

MR. SIESS: The light water reactor people really haven't had to look at this. They can say we don't have that kind of pipe or those temperatures. I don't think anybody in that area really went in and asked some of the things you talked about there.

MR. WAREMBOURG: They experienced no structural damage to the building.

MR. SIESS: It blew out a panel between --

MR. WAREMBOURG: Just blew down the steam line.

MR. SIESS: There was something between the line and the control room --

MR. WAREMBOURG: There was a lunch room door and they had modified the door and stuck an air conditioner in there and they had that door with a door air conditioner, and it blew that door open. That's where people got killed. It shoved everybody in the lunch room back against the wall, so the people that got killed were the people in the lunch room.

MR. MC KINLEY: The operators in the control room were not --

MR. WAREMBOURG: They didn't experience any adverse effects. It did fill the room full of steam, but typically, he said, they were back in within 15 minutes on lifesaving operations and they had a stay time of 10 or 12 minutes before they had to come back out.

MR. WARD: Thank you.

MR. NIEHOFF: The next slide just provides a similar family of curves for the reactor building.

MR. SIESS: They don't look that much different. The turbine building has a lot more volume. This is a very local-type thing then? You said this was a whole building temperature?

MR. NIEHOFF: That's correct. It is a bulk environment. In a lot of these breaks, once you assume a single failure you are blown down --

MR. SIESS: What's the volume of the two buildings?

MR. WAREMBOURG: They are not that different. The reactor building is a lot more spread out.

MR. HOLMES: The reactor building volume was only on this side of the wall. The other is considered outside that. I don't think we're looking at too much difference in terms of cubic feet.

MR. NIEHOFF: In terms of some of the other impacts of the EQ program, due to problems we encountered in doing the analysis and some of the material limitations of the various rubbers and electronic components, that we could not verify information through the original manufacturer, we decided to replace some 350 solenoid valves, some 50 transmitters, approximately 50 thermocouples and 12 motors.

MR. SIESS: These were replaced not because they were found defective but because you didn't have qualification data? You bought something that had not been qualified?

MR. NIEHOFF: A lot of the solenoid valves had solenoid rings. Some of the things like transmitters we couldn't identify positively the manufacturers of the components. Couldn't do the aging analysis because of that. We're also providing upgrades to a lot of other equipment. Someone mentioned our original plant design included a taped splice, basically had two ring ton lugs taped together with black electrical tape. Those types of splices were not really well documented in our original test program. We know there were some included and they did pass some of the original profiles, but again, it became something that was very difficult to treat from an aging basis and we decided to go to this Raychem splice, which is a sling tube type of material.

MR. SIESS: How many splices did you have to do that to?

MR. NIEHOFF: Oh, basically there's a splice at each solenoid valve, any number of junction boxes with either millivolt or --

MR. SIESS: Do you have someplace you can go on the record that tells you where the splices are or just do it by walkdown?

MR. NIEHOFF: A lot was accomplished by walkdown.

MR. SIESS: Follow every cable to the end to see if there's a splice?

MR. NIEHOFF: That's right. There are certain categories of equipment we know have splices, the solenoid valves, some of the thermocouples. I'm hard pressed to say there's a few thousand.

MR. WAREMBOURG: We're looking typically at 4000 Raychem splices.

MR. SIESS: Those are mechanical type of splices? I'm not familiar with it.

MR. NIEHOFF: Again, it can consist of a lug connector that's bolted together or it can be a cinch connector. Instead of a tape, you put over a sling tube type of material to give you a better seal. Other impacts, we have some moisture sealing and protection going on. We did determine there was a very high likelihood that our fire detection system would go off due to the steam environment.

In terms of other activities, as I said, we're continuing to develop our program. There's a lot of procedures being revised in terms of preventative maintenance, quality assurance, procurement, engineering, the whole gamut of our activities. We have lots of training to do on these procedures, obviously.

In terms of our current plans, we're in the process to rise to 35 percent power and plan to run there until May 31, 1986, and we will shut down to perform the EQ construction work. We've estimated approximately 90 days of construction activities. We're trying to work some of this while the plant is at power, so it is a little difficult at this time to estimate what the required outage would be on May 31. As Mike indicated earlier, we are going to request Commission approval to operate at 35 percent power following EQ construction work while NRC program reviews and SLRDIS tech spec approvals are taking place:

MR. WARD: What's going to happen on May 31 is put in the SLRDIS system and --

MR. NIEHOFF: The SLRDIS system is tied into the tech specs, so portions of the SLRDIS system are in the program now, but we can't tie that system into our plant protective system until we have that tech spec in place.

MR. SIESS: Thank you.

MR. HOLMES: I'm Mike Holmes, nuclear licensing manager. The next subject concerns steam generator tube integrity requirements, NUREG-0844, and our response to it.

MR. SIESS: Excuse me. I've glanced through this. What I didn't find readily: What are the consequences of a steam generator tube failure?

MR. HOLMES: I can certainly talk about that.

MR. SIESS: It helps us because when we look at fixes we usually have some consequence that we are trying to avoid and I think we have some idea what they are for a water reactor and I'm not sure I have the same feel for what they are for Fort St. Vrain.

MR. HOLMES: Let me briefly talk to the two types of consequences that result at our plant. Our steam generators have two heat transfer sections: One section which produces the main steam, and the reheat section which produces the hot reheat steam. The consequences of an accident with tube rupture of those two sections are different. The first, the feedwater and main steam in that section is at a higher pressure than our primary coolant, helium. If those tubes leak, we get water into the primary coolant system, unlike the water reactor where the primary coolant will leak into the secondary coolant. With water into the primary coolant system we have the complete array of moisture monitoring devices and automatic trips depending on the moisture level that would scram the plant, and in some cases, depending on the severity of the leak, it would result in a dump of one of the steam generator feedwater inventories.

There's of course two sections to each steam generator -- excuse me, two loops associated with each. One of the two would be dumped to a steam water dump system and the FSAR has analyzed a complete spectrum of steam generator tube rupture possibilities and up to and including the wrong loop and having to reco er that and dump the right loop and maintain cooling during the process. Again, there would be a possibility of some primary coolant getting into the steam water dump tank which would be detected in the reactor building. The radiological consequences are relatively minute.

MR. SIESS: Well below DBA 2?

MR. HOLMES: Oh, yes. From the slide I had earlier --

MR. SIESS: Is this sensitive to the number of tube failures?

MR. HOLMES: Everything we talk about here would be bounded by the maximum hypothetical accident which involves the release of the entire primary coolant inventory over a few-hour period. That's the release through a two-inch diameter line where it goes through the helium purification regeneration section, and some multiple failures, and no operator actions, the whole inventory bleeds down. Any steam tube generator rupture would be a smaller diameter tube that would feed a leak path. Assuming you don't do anything to isolate it, it would keep bleeding down. I can pull out my chart, but that's an order of magnitude, maximum hypothetical accident -- an incredible accident.

MR. SIESS: You had a maximum hypothetical release, that was something else.

MR. HOLMES: It is a small fraction, orders of magnitude less than 10CFR100 guidelines. The reheat steam line rupture would be a little more in accordance with water reactor thinking. The reheat steam pressure is less than the primary coolant helium pressure, primary coolant would leak out through the tube leak or the rubber depending on the size of the accident. There are radiation monitors that would detect the increase in radiation levels and shut the isolation valves or shut down, stop the leak. That would be that. Does that give you a feel for the accident consequences?

MR. SIESS: You wouldn't loose primary coolant?

MR. HOLMES: You would loose it to the secondary steam system but still have plenty of primary coolant to shut down and cool down with.

MR. SIESS: That's what I wondered.

MR. HOLMES: We always have atmospheric pressure around to help us out. And with feedwater, that's plenty of motive power and circulation and coolant capability.

MR. SIESS: That helps. Thank you.

MR. HOLMES: The steam generators in our plant we feel are one of the highlights or better performing areas that we're involved with. Over the life of the plant, we have had two small leaks occur in our steam generators. The first leak occurred in November of '77 and the second leak occurred in September cf '82, approximately five years later. They were both small in size, much smaller than were analyzed in our FSAR accident analyses for steam ,enerator offset tube rupture.

The second leak which we have more data on was about a three-mill hole that once we finally determined that the water we were dealing with at the time actually came from a steam generator tube leak than some other source, we were shut down at the time and took a while to track where the water was coming from. The first leak occurred when the plant was operating and over a period of hours we watched the moisture monitor indications build up and it was obvious we had a steam generator tube leak. You can confirm you have one of these tube leaks, you drain the portion of the steam generator that is suspect to the steam water dump tank and detect for cooler. Our steam generators do have extra tube and heat transfer capacity built into them, about a 15 percent extra margin, so that as we plug the tubes and actually plug the subheaders that lead into the tube -- and I'll show you some diagrams of that in a minute -- but we can withstand several of these, 15 percent of about 200 tubes, so perhaps 30 leaks, and then there's a distribution of those and these are analyzed in the FSAR.

MR. SIESS: How many subheaders can you stand?

MR. HOLMES: About 216 subheaders and 15 percent, talking about 30 of them. One leak was in a loop 1 steam generator module. The other was in a loop 2 steam generator module. Both of the leaks occurred toward the bottom coil of the superheater 2 at or near a floating tube support plate. I'll try to illustrate where that is. Here's a picture of the steam generator 2 module. This is the basic 2 module. This is the superheater 1 section. The feedwater is actually superheated by the time it gets here. It goes down through a helicoil and exits through a 3 D tube bundle down through the center of the EES section and out there are some subheader connections here. I'll illustrate those better in a minute. Both tube leaks were roughly 4 to 6 inches above the bottom of the superheater 2 tube bundle, not near any welds or 3 D bends. From the elevation of the leak they could have been near or adjacent to a tube support plate. I'll get into that in a minute. But outside of being roughly the same elevation on the same tube bundle, two different loops --

MR. SIESS: I thought the first leak was attributed to a piece that was loose in there.

MR. HOLMES: We don't know what to attribute it to but based on speculation, yes, that's one of the leading contenders.

As I mentioned, the leaks were in the coil part of the tube bundle. Metallurgical examinations that were able to be conducted were conducted on specimens taken from the external subheader that leads into and out of the steam generator module. Let me show you where that is. The tube bundle just pictured was this part here. There's a primary closure blade near the PCRV interior surface. You have the penetration through the PCRV roughly 15 feet thick at this point. On the EES bundle, which is where the leaks occurred, there's a feedwater ring header that leads in and a main steam ring header on the outside here, and it is these tube sections between this point and this point and the other one in this point and this point, that we cut out a section of a subheader and plug the two ends.

MR. SIESS: You say you did not examine the cracked section?

MR. HOLMES: Right, we examined the subheader line going in and the line coming out. In this case the line coming out is identical to the material in the superheated 2 tube bundle where the leak was found to exist. That tells us something about the alloy material that has been exposed to -- well the main steam conditions. That's not a one-to-one correlation, but you got the same material, same fluid and I'll get into results in a second

So we did look at the alloy 800 tubing material that was connected to the main steam ring subheader. There was an oxide film of approximately 8 mills thick on the interior of that subheader tubing material. There was no evidence of pitting, cracking, erosion, corrosion. They had fine-grained microstructure typical of what you would expect of alloy 800, grade 1. No evidence of hardening. Portions of that subheader are bent to get the various configurations needed. Grain boundaries were free of carbide precipitation. Essentially everything appeared to be in good order exactly like you would expect it to be. No evidence of degradation whatsoever.

The carbon steel tubing on the feedwater inlet was examined also. We have not had any failures of carbon steel or chrome moly parts of the bundle. There was a magnetite corrosion film on ID between 10 on 40 mills thick.

Microstructure of the carbon steel appeared to be what it was supposed to be. The thickness of that film did indicate the likelihood that at some point this time we would have to do some chemical cleaning of the tube bundle.

MR. SIESS: You clean it to restore the heat transfer characteristics, not to prevent cracks?

MR. HOLMES: Right.

MR. WARD: Is this film on the inside or outside?

MR. HOLMES: These are the results of looking at the ID. The OD has insulation around it. From a temperature standpoint versus the helium inside it is not too meaningful to look at the exterior. Nothing on the exterior is notable. We did consider a number of potential steam generator tube leak causes. I'll quickly run through the list here. The residual stress is due to cold working in the tube bins. That's a possible concern. None of these could be pinpointed. Some are more probable than others perhaps.

Weld joint defects we looked at and it came in from the construction records there were no weld joints in the area of the leaks. The vibration fatigue stresses during original design and testing there was air flow tests conducted on tube flow bundles and some sleeve and wedge assemblies utilized to secure the tubes at appropriate spacings to keep the vibrations down -- and I'll get to that in a second -- as being a possible contributor to the cause.

A feedwater chemistry was looked at. That's pretty well representative of the subheader internal situation and that didn't appear to be much of a concern.

General or crevice corrosion was considered not much to say there. Sleeve and wedge assembly, that's a possible consideration. A cold springing during fabrication, when the tubes were put over where they had to weld the down comers to the subheader arrangement could result in strained relaxation during operation. That was considered.

Low cycle fatigue due to operational cycles, we considered that. A crack propagation from defect during fabrication was looked at. Carbonization of alloy 800 was considered. Loss of tube sleeve wedge assemblies. A complete gamut of things were considered and nothing could be positively identified from the external look we had at the situation.

MR. SIESS: I look at that list. I think many items in it could account for the crack in a steam generator tube, but I only see one that I would think could credibly account for only one crack in the steam generator tube. If you had a fatigue problem, vibration fatigue, the probability you would only see one crack, and two cracks out of what, 12 steam generators is vanishingly small.

MR. HOLMES: One of the significant pieces of data we can acquire with operation is the rate at which leaks appear, and if we get one leak every five years during the life of the plant we're not too worried about it.

MR. SIESS: It is not going to be due to fatigue either.

MR. HOLMES: Our evaluation at the time concluded that the leaks were probably random in nature. We did receive a subsequent analysis from GA that postulates that the cause might have been due to flow-induced vibration caused by the loss of some sleeve and wedge assemblies. Let me show you what that is. In the tube bundles we do have support plates with the tube going through a hole in the support plate. In order to keep the tube from vibrating around and wearing, we have a two-piece sleeve and wedge assembly.

MR. SIESS: I've seen i

MR. WARD: I haven't.

MR. HOLMES: One piece has a decrease in diameter wedge that goes this way and the other piece fits over it. Basically you fit the sleeve through the support plate and then drive the wedge into it to tighten the whole thing up and secure it. During manufacturing it was noted that after securing sleeve and wedge assemblies, inspectors would come in later on and find some loose ones that were not secured, tight. Looking at what what he call the spare steam generator module, which is the air test flow module we have at the plant, it is possible to walk up to it and find some random sleeve and wedge assemblies. If one came loose, with that long portion of the tube that is the exhaust of the main steam -- that shows one tube. Feedwater subheader comes in, breaks into three tubes here, which is why it is so difficult to inspect in place. The tube goes through the heat coil, changes material here. There's actually carbon steel here, 2-1/4 chrome moly and changing here to -- if there were a sleeve and wedge assembly at or near the first tube support plate up in the helicoil that came loose, this would obviously be a candidate for vibration and that might wear. That's really pure speculation. But it is perhaps the most probable cause.

MR. WARD: How many are there in that one generator?

MR. HOLMES: Out of the 216, times three tubes, there's a bunch. Per module -- oh, sleeve and wedge assemblies, there's thousands.

MR. SIESS: I thought you had actually detected a loose piece. Am I wrong or is this just speculation?

MR. IRELAND: I recall that the first leak had once upon a time been associated where it was postulated that a tip of aluminum pry bar got lost. Has that been discounted?

MR. HOLMES: Knowing that that particular module, the tip of the pry bar was lost in it, we did closely examine the interior of the subheader where the main steam exited for any traces of aluminum contaminant. There were none. I guess you could conclude from that whatever you can conclude.

MR. IRELAND: I would assume that the flow out of the tube of steam, water, whatever it was being higher than reactor pressure would not have carried much aluminum down to the point of examination.

MR. HOLMES: We couldn't detect any evidence of aluminum on the interior of that subheader and whether we would be able to to if that was the cause of the failure or not --

MR. IRELAND: So it remains a mystery.

MR. HOLMES: We couldn't conclude anything one way or the other. We did not lose an aluminum pry bar tip in the other module, so --

Basically we're telling you what we do before we tell you the responses we submitted to the NUREG, which we have a little harder time relating those staff recommendations to our steam generator. In response to both tube leaks, and given the overall industry concern with steam generator tube leaks, we worked with the staff in order to try to formulate a surveillance program to deal with future steam generator tube leaks once the second one had occurred.

We proposed the tech spec change that would enhance or officialize the surveillance monitoring that it was possible to do given the steam generator tube leak. We do continuously monitor primary coolant for water and the secondary reheat steam for radiation products. That's already required by the tech specs so we went beyond that for steam generator tube rupture monitoring provisions, surveillance requirements.

Basically, this is late 1984, November of '84, we agreed that with each new tube leak that developed, it would be evaluated to determine the size of the leak, the elevation of the leak, we can determine where in the tube bundle this leak happened by a gas/water interface and measuring the amount of the water and where it starts and stops and so forth, and evaluate the potential cause of the leaks.

MR. SIESS: That's not new, is it?

MR. HOLMES: We had done this for two tube leaks on our own, for our own information and interest, of course providing that for the NRC.

MR. HOLMES: This tech spec says we have to do it for future steam generator tube leaks. We would look at these accessible metallurgical specimens from the subheaders. We also committed to advise our steam generator feedwater chemistry program to incorporate some steam generator owners' group guidelines. We've had a consultant come in here.

MR. SIESS: What was your chemistry before and what is it now?

MR. HOLMES: Basically our chemistry only permits very, very low amounts of --

MR. SIESS: Low volatile treatment?

MR. HOLMES: Yes. There were a few limits that were shuffled up or down based on the consultant's recommendations.

MR. SIESS: Your tube material is what? There's two different kinds?

MR. HOLMES: Some carbon steel, some 2-1/4 chrome moly and some alloy 800. We tried to apply them to our plant appropriately.

MR. SIESS: If I only had two tube failures in that time I wouldn't have touched the chemistry.

MR. HOLMES: The changes were not major by any means.

MR. SIESS: This was specific to Fort St. Vrain, was it?

MR. HOLMES: Our biggest concern is just we measure our feedwater contaminants in the parts per billion level except for the volatile stuff.

I wanted to just briefly go through the difference between our steam generator and most pressurized water reactor steam generators. The bulletin was addressed to to understand why we are not doing a lot of the things the staff suggested that we do. The bulletin came out a couple months after we finished getting our modules installed inside the PCRV, where the modules are out in the reactor building in the primary coolant loop. We really don't have provisions for in situ steam generator module inspection. Our nearest equivalent would be the removal of the module from the PCRV.

Theoretically, during the design of the plant, that's a possibility, but you certainly wouldn't want to do it for inspection reasons. If we ever had too many steam generator tube leaks we could complete the design and fabrication, but it is not as simple as that. I've already reviewed the likely leak paths from secondary to primary and in the EES section.

We think our steam generator tubes are less susceptible overall to leaking. We don't have some of the crevices and the chemistry at the crevices that you would find on a PWR steam generator. Our tube walls are relatively thick, in the 1/8 of an inch to a 1/4 of an inch range. The feedwater is on the inside of the tubes. There are not particular obstructions, crevices, structures or other things for the feedwater to get tangled up with, versus the PWR feedwater being on the outside surfaces where there are crevices. On the outside of the tubes we do have the tube support plates. They are in contact with normally -- hopefully -- dry inert helium, and we do have the ones through steam generator design that requires a strict water chemistry program to minimize contamination of the interior of the tube and the effects that that would have on heat transfer. With those differences in mind, we developed a response to the specific staff recommendations of the NUREG.

MR. SIESS: What's the timing on this?

MR. HOLMES: This was submitted about mid '85, spring to summer of '85. We really haven't received any questions or feedback or further discussions with the staff on our responses at all. I'm not sure whether there's something that might be forthcoming or not. The first staff recommendation that we inspect the secondary side of the SG for loose parts and foreign objects and external damage is impractical for FSC because this is the internal side of the tubes where the SG design precludes the likelihood of foreign objects or loose parts.

Also, inaccessability of the SG tube bundles precludes introduction of foreign objects on the outside surfaces of the tubes. The ranges for normal access to that part of the primary coolant system, we don't think there's a great deal of opportunity to introduce foreign objects just the way other machines do access. What materials we have there are fairly inert. The second staff recommendation concerned the QA procedures to account for foreign objects that could be left in the steam generator during an inspection. Again, due to the difficulties and in fact the impossibility of us doing a steam generator inspection, we do have QA procedures that address loose parts when we're doing maintenance, and we didn't think we needed to take that any further specifically relative to the steam generator inspections.

The third recommendation involved inspecting the entire length of the tube for OD degradation, and our tubes are not accessible for things like that given that subheader configuration that we have. We have a continuous leak monitoring, of course.

The fourth staff recommendation concerned an action that recommended inspection interval of 72 months to get back to assess tube degradation as opposed to our every tube leak, and basically indicated a preference to stick with the every tube leak.

The next staff recommendation dealt with the steam generator water chemistry guideline. That has been incorporated in our water chemistry control procedures.

The next staff recommendation concerned the condenser and minimizing condenser tube leaks which could be a source of contaminant into the condensate feedwater. We do a number of things relative to our condensate and we do have

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full flow polishing the mineralizers and aerators to remove impurities before it enters the steam generator. Water chemistry is continuously monitored and recorded and if it gets out of spec we need to know it so we don't gum up the steam generators. We have checked our water chemistry. We did have a number of condenser tube leaks occur in the mid to late '70s primarily because we were operating condensors at lower power levels than for which they were designed and were getting steam condensed in the wrong place. We did retube those portions of the condenser in late 1979 with reinforced stainless steel tubes to deal with that low or partial power situation that we usually find ourselves in, and we have not had a great deal of leak difficulty since then. We do go into the main condenser at each major outage to see what the situation is.

MR. SIESS: What things did the staff recommend that you are not doing? We didn't detect any staff concerns that were, let's say, surprising or whole new areas that we could apply that we hadn't been doing something already. You feel you are in compliance with that recommendation?

MR. HOLMES: What we're doing we feel is frequent enough and appropriate to our particular situation, and would largely be responsive to their condenser recommendations, not one for one, but responsive.

The last staff recommendation in the NUREG, this concerned limits on the leakage from primary coolant to the secondary coolant system. We have extremely low feedwater leakage rates. In fact it is essentially zero, due to graphite oxidation concerns, so that's not a particular problem. We have a tech spec on allowable amounts of leakage of primary coolant into the secondary coolant system and in the event of a steam release of some sort, to keep the radiation consequences within allowable limits, so our leakage rate sizes are covered in tech specs that are appropriate for our configuration at the plant.

The next staff recommendation concerns adopting tech spec limits on iodine. We already have a standard -- or not a standard, but our own tech spec for iodine that keeps us within the 10CFR guidelines, and that's a more appropriate criteria for determining iodine limits for our particular plant.

Lastly, the staff recommended action to modify the control logic for safety injection pumps. We don't have any pumps or anything close to that.

MR. HENSON: Did you address the potential of impingement on the tubes by the boron balls that could possibly leak through the system and get into the primary coolant or the cracked graphite?

MR. HOLMES: We assessed the metallurgical impacts of, let's say, carbon in general in contact with the reheater section primarily. Carbonization of steam generator tubes is a possible concern. The plate out probes have metallurgical samplings on them. These are located at the inlets of the steam generators. They do have metallurgical samplings on them to see if we're getting carbonization, whether it is boron balls or carbon in general. We do track and see if there's anything happening there. The first plate out was removed, we looked at the stainless steel and the zinc alloy samples on that and there was no carbonization that would present any problem.

MR. WARD: I thought the question was directed more toward --

MR. HOLMES: Are you worried about the boron --

MR. HENSON: Mechanical damage.

MR. HOLMES: Carbide balls, they tumble down the guide tube and go into a blind-ended hole.

MR. HENSON: I guess there's a mine.

MR. HOLMES: If they overflowed the top they would end in the tube going up. There's no overflow provision for the balls. They are measured and are not supposed to get above the top of the reactor core, so outside of fine leaking out between the fuel element or something -- these balls are real light and they bounce off the tubes and they could end up, I suppose, being in some crack or crevice, but between the boron and the carbide I don't know that that would

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present a major concern.

MR. SIESS: Gentlemen, this is going to be it for today's session. Weather permitting, we will reconvene tomorrow morning at 8:30. We will take up items G, H, C and F more or less in that order. If we finish up at a suitably early time, Mr. Ward and I would probably take a short plant visit. You can see how we're going in the morning. I know you have to make security arrangements for that.

Again, depending on the weather, we'll know when we have to leave. Both of us have to be in Washington. If Mr. Ward and I do not manage to find time for the plant tour, Mr. McKinley would like to go as our proxy.

(Whereupon, at 6:05 p.m., the meeting was adjourned.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proc..dings before the UNITED STATES NUCLEAR REGULATORY COMMISSION in the matter of:

NAME OF PROCEEDING: ADVISORY COMMITTEE ON REACTOR SAFEGUARDS SUBCOMMITTEE ON FORT ST. VRAIN

DOCKET NO.:

PLACE: PLATTEVILLE, COLORADO

DATE: WEDNESDAY, APRIL 2, 1986

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission.

(sigt) Kathie S. Weller/sg

(TYPED)

KATHIE S. WELLER

Official Reporter

ACE-FEDERAL REPORTERS, INC.

Reporter's Affiliation

ACRS SUBCOMMITTEE MEETING ON FORT ST. VRAIN

LOCATION LONGMONT, COLORADO

DATE APRIL 2-3, 1986

ATTENDANCE LIST

PLEASE PRINT:

NAME	AFFILIATION
L. Milton McBride	PSC
Tim Prenger	PSC
H DUBROFF	Denver Post

ACRS SUBCOMMITTEE MEETING ON FORT ST. VRAIN

LOCATION LONGMONT, COLORADO

DATE APRIL 2-3, 1986

ATTENDANCE LIST

PLEASE PRINT:

NAME	AFFILIATION
Fred Tilson	PSC
Jack Kennedy	GA Technologies
Mike Niehoff	PSC
MICHAEL H. HOLMES	PSC
Richard L. Craun	PSC
Frank J Novachek	PSC
Robert J Hix	Office of Consumer Counsel
WARREN WENDLING	Colo Public Utilities Comm.
Mark Bender	Colo Attorney General's Office
KATHY OWENS	PSC
[illegible]	PSC
DAVID GOSS	PSC
Jim Gramling	PSC
M. J. FERRIS	PSC
[illegible]	[illegible]
THOMAS D. McINTIRE	PSC
H. G. Olson	NFSC Member
Dan Mears	GCRA
DAVID ALBERSTEIN	GA TECHNOLOGIES + NFSC
[illegible]	PSC
G.T. Quinn	SWEC
RH LANE	SWEC

ACRS SUBCOMMITTEE MEETING ON FORT ST. VRAIN

LOCATION LONGMONT, COLORADO

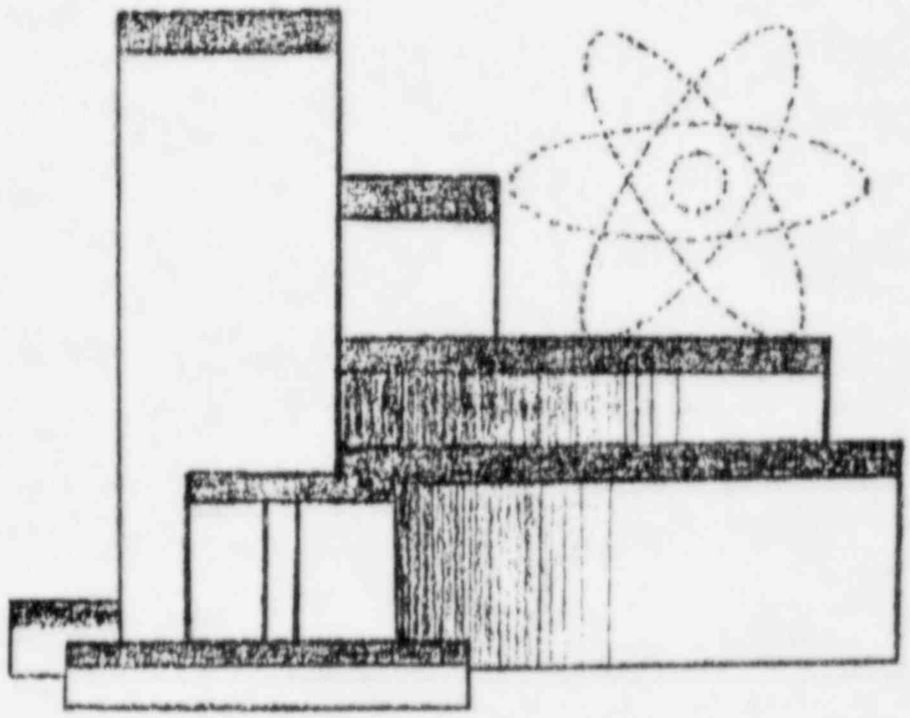
DATE APRIL 2-3, 1986

ATTENDANCE LIST

PLEASE PRINT:

NAME	AFFILIATION
SIESS, CHESTER P.	ACRS SUBCOMMITTEE CHAIRMAN
WARD, DAVID A.	SUBCOMMITTEE MEMBER
McKINLEY, JOHN C.	ACRS Staff
MARTIN HANRAHAN	COLO DEPT OF HEALTH
Williams, Peter	NRC - NRR
Heitner, Kenneth L.	NRC - NRR - SSPB
IRELAND, RICHARD E.	NRC - RIV
JAUDON, Johns P.	NRC - RIV
Farrell, Robert E	NRC - RIV, SRI
FORTESCUE, PETER	NRC (Consultant)
BERKOW, HERBERT	NRC - NRR
LYNCH, Oliver D.T.	NRC-NRR-SSPB
HINSON, Charles S.	NRC - NRR - SSPB
[illegible]	[illegible]
M.B. Dolphin	GA Technologies
R F Walker	[illegible] Co.
H. L. Brey	PSC
DON WAREMBOURG	PSC
[illegible]	PSC
TED BORST	PSC
JACK WILLIAMS	PSC
John Reesy	PSC

Fort St Vrain



PUBLIC SERVICE COMPANY
OF COLORADO

ACRS MEETING
APRIL 2/3, 1986

FIRE PROTECTION (APPENDIX R)

FIRE PROTECTION EVALUATION PROGRAM

LICENSING CRITERIA

APPLICABLE CRITERIA

- 10CFR50.48, FIRE PROTECTION
- 10CFR50, APPENDIX R, SECTION III.G,
  FIRE PROTECTION OF SAFE SHUTDOWN CAPABILITY
- 10CFR50, APPENDIX R, SECTION III.J,
  EMERGENCY LIGHTING
- FIRE PROTECTION SAFE REACTOR SHUTDOWN/COOLDOWN CAPABILITY
  FOR THE FORT ST. VRAIN NUCLEAR GENERATING STATION

CRITERIA THAT DO NOT APPLY

- 10CFR50, APPENDIX R, SECTION III.L,
  ALTERNATE AND DEDICATED SHUTDOWN CAPABILITY
- 10CFR50, APPENDIX R, SECTION III.O,
  OIL COLLECTION SYSTEM FOR REACTOR COOLANT PUMPS

FIRE PROTECTION EVALUATION PROGRAM

FSV FIRE PROTECTION ACCEPTANCE CRITERIA

NON-CONGESTED CABLE AREAS

- MEANS SHALL BE AVAILABLE TO SHUT DOWN AND COOL DOWN THE REACTOR SUCH THAT NO FUEL DAMAGE OCCURS (i.e. MAXIMUM FUEL PARTICLE TEMPERATURE DOES NOT EXCEED 2900°F)

- THERE SHALL BE NO SIMULTANEOUS RUPTURE OF BOTH A PRIMARY COOLANT BOUNDARY AND THE ASSOCIATED SECONDARY CONTAINMENT BOUNDARY SUCH THAT NO UNMONITORED RADIOLOGICAL RELEASES OF PRIMARY COOLANT OCCUR

- ACHIEVE AND MAINTAIN SUBCRITICAL REACTIVITY CONTROL

- MAINTAIN PCRV LINER INTEGRITY AND PCRV STRUCTURAL AND PRESSURE CONTAINMENT INTEGRITY

- ACHIEVE AND MAINTAIN FORCED CIRCULATION COOLING TO REMOVE DECAY HEAT

- MAINTAIN PROCESS VARIABLES MONITORING AND CONTROL FUNCTIONS

- PROVIDE SAFE REACTOR SHUTDOWN/COOLDOWN SUPPORTING FUNCTIONS

FIRE PROTECTION EVALUATION PROGRAM

FSV FIRE PROTECTION ACCEPTANCE CRITERIA

CONGESTED CABLE AREAS

° MEANS SHALL BE AVAILABLE TO SHUT DOWN AND COOL DOWN THE REACTOR SUCH THAT THE CONSEQUENCES OF DBA NO. 1 (PERMANENT LOSS OF FORCED CIRCULATION COOLING) ARE NOT EXCEEDED

° ACHIEVE AND MAINTAIN SUBCRITICAL REACTIVITY CONTROL

° DEPRESSURIZE THROUGH THE HELIUM PURIFICATION SYSTEM

° USE LINER COOLING TO MAINTAIN PCRV INTEGRITY AND REMOVE DECAY HEAT

° MAINTAIN PROCESS VARIABLES MONITORING AND CONTROL FUNCTIONS

° PROVIDE SAFE REACTOR SHUTDOWN/COOLDOWN SUPPORTING FUNCTIONS

EQUIPMENT QUALIFICATION

ORIGINAL FSV EQ PROGRAM

- HELB ISOLATED BY AUTOMATIC/MANUAL ACTIONS WITHIN FOUR MINUTES

- INITIATE SAFE SHUTDOWN, FORCED CIRCULATION COOLING USING FIREWATER

- WORST CASE HARSH ENVIRONMENTS

  - COLD REHEAT STEAM LINE BREAK IN REACTOR BUILDING

  - HOT REHEAT STEAM LINE BREAK IN TURBINE BUILDING

- EQUIPMENT QUALIFIED BY TESTING TO VERY HIGH PEAK TEMPERATURES OVER A 30-MINUTE TEST PERIOD

- NO EQUIPMENT AGING REQUIREMENTS SINCE THE REQUIRED SYSTEMS WERE ROUTINELY IN OPERATION, AND WERE ACCESSIBLE FOR NORMAL MAINTENANCE AND REPAIR.

CONCERNS WITH ORIGINAL FSV EQ PROGRAM

- NRC POLICY THAT REACTOR OPERATORS CANNOT BE RELIED UPON TO TAKE PROPER ACTIONS IN LESS THAN TEN MINUTES UNDER ACCIDENT CONDITIONS

- ACCESS MAY BE REQUIRED TO HARSH ENVIRONMENT AREAS TO TAKE MANUAL ACTIONS

- EQUIPMENT TESTING OF TOO LIMITED A DURATION TO VERIFY REQUIRED OPERABILITY TIMES

- EQUIPMENT AGING NOT TREATED PROPERLY

BASIS FOR REVISED FSV EQ PROGRAM

- ELECTRICAL EQUIPMENT CANNOT SURVIVE FSV STEAM TEMPERATURES FOR TEN MINUTES

- OPERATORS HAVE UP TO 90 MINUTES TO RECOVER FROM A LOSS OF FORCED CIRCULATION (LOFC) COOLING

- AUTOMATICALLY INITIATE AN LOFC UPON DETECTION OF A HELB

- MANUALLY INITIATE SAFE SHUTDOWN, FORCED CIRCULATION COOLING USING FIREWATER

- MANUAL ACTIONS FROM MILD ENVIRONMENT AREAS ONLY

FSV EQ PROGRAM

SCHEDULE EXTENSION REQUEST

NOVEMBER 1985

EXCEPTIONAL CIRCUMSTANCES

- BEING AN HTGR, FSV EXPERIENCED HIGHER TEMPERATURE HARSH ENVIRONMENTS. FSV WAS NOT ABLE TO USE MOST INDUSTRY EQUIPMENT QUALIFICATION DATA.

- A 1980 NRC ORDER REQUIRED PSC TO APPLY THE DOR ENVIRONMENTAL QUALIFICATION GUIDELINES "TO THE EXTENT APPLICABLE TO A GAS-COOLED REACTOR". THE NRC DID NOT RESPOND IN WRITING UNTIL 1985 TO PSC'S APPLICATION OF THE EQ GUIDELINES TO THE FSV HTGR.

- ALTHOUGH NRC STAFF GUIDANCE SINCE JANUARY 1985 HAS BEEN HELPFUL, NO COMPREHENSIVE NRC TECHNICAL EVALUATION REPORT OR SAFETY EVALUATION REPORT ON THE FSV EQ PROGRAM HAS BEEN PROVIDED.

- THE FOUR-MINUTE OPERATOR RESPONSE TIME TO A HELB HAD TWICE PREVIOUSLY BEEN REVIEWED AND ACCEPTED BY THE NRC IN WRITTEN SAFETY EVALUATION REPORTS. THE 1985 NOTIFICATION TO PSC THAT OPERATORS COULD NOT BE RELIED UPON TO RESPOND IN LESS THAN TEN MINUTES RESULTED IN A FUNDAMENTAL CHANGE IN THE PREVIOUSLY APPROVED BASIS FOR THE FSV EQ PROGRAM.

FSV EQ PROGRAM

SCHEDULE EXTENSION REQUEST

NOVEMBER 1985

JUSTIFICATION FOR CONTINUED OPERATION

- 35 PERCENT POWER LEVEL RESTRICTION DURING THE EQ SCHEDULE EXTENSION PERIOD EXPIRING MAY 31, 1986
- MAXIMIZE RELIANCE ON NON-ELECTRICAL EQUIPMENT AND SYSTEMS WHICH CAN BE MANUALLY ACTUATED TO MITIGATE A HELB
- UTILIZE PCRV LINER COOLDOWN WITH FIREWATER
- DEPRESSURIZATION OF THE PRIMARY COOLANT SYSTEM NOT REQUIRED
- ACTUATION OF THE RESERVE SHUTDOWN SYSTEM NOT REQUIRED
- NO SIGNIFICANT FUEL PARTICLE COATING FAILURES DURING RESULTING CORE TEMPERATURE TRANSIENT
- INTEGRITY OF PCRV LINER AND CONCRETE IS MAINTAINED. SOME LOCAL PCRV CONCRETE OVERHEATING AND THERMAL BARRIER DAMAGE MAY OCCUR.
- WITH THE 35 PERCENT POWER LEVEL RESTRICTION, THERE WOULD BE NO SIGNIFICANT IMPACTS ON PUBLIC HEALTH AND SAFETY AS THE RESULT OF A HARSH ENVIRONMENT ACCIDENT

FSV EQ PROGRAM

LICENSING ISSUES

- ° AUTOMATIC STEAM LINE RUPTURE DETECTION/ISOLATION SYSTEM (SLRDIS) INVOLVES AN UNREVIEWED SAFETY QUESTION
  - A TECHNICAL SPECIFICATION CHANGE IS REQUIRED TO MODIFY THE EXISTING PLANT PROTECTIVE SYSTEM
  - THERE IS AN INCREASED PROBABILITY OF OCCURRENCE OF A 30-MINUTE INTERRUPTION OF FORCED CIRCULATION COOLING AS ANALYZED IN THE FSAR
  - THERE IS A REDUCED MARGIN OF SAFETY FOR ASSURING CONTINUED FORCED CIRCULATION COOLING

- ° ENVIRONMENTAL QUALIFICATION OF DBA EQUIPMENT
  - 10CFR50.49 PRESUPPOSES THAT DESIGN BASIS ACCIDENTS CREATE WORST CASE HARSH ENVIRONMENTS
  - NRC POSITION THAT NO FISSION PRODUCT BARRIERS SHOULD BE DEGRADED DURING HARSH ENVIRONMENT ACCIDENTS

FSV EQ PROGRAM

LICENSING ISSUES

° FSV DESIGN BASIS ACCIDENT NO. 1
PERMANENT LOSS OF FORCED CIRCULATION COOLING

- DBA NO. 1 DOES NOT CREATE A HARSH ENVIRONMENT
- DBA NO. 1 EQUIPMENT WILL EXPERIENCE A HARSH ENVIRONMENT DURING A HELB
- DBA NO. 1 EQUIPMENT IS NOT REQUIRED TO RESPOND TO A HELB
- DBA NO. 1 RESULTS IN FUEL PARTICLE COATING DEGRADATION
- CURRENT NRC POSITION IS THAT DBA NO. 1 EQUIPMENT WHICH EXPERIENCES A HARSH ENVIRONMENT MUST BE ENVIRONMENTALLY QUALIFIED
- PSC IS PREPARING A 10CFR50.49 EXEMPTION REQUEST BASED ON COMPOUNDED, LOW PROBABILITY ACCIDENT CONDITIONS

FSV EQ PROGRAM

LICENSING ISSUES

° FSV DESIGN BASIS ACCIDENT NO. 2
DESIGN BASIS DEPRESSURIZATION ACCIDENT

- DBA NO. 2 CREATES A HARSH ENVIRONMENT (NON-WORST CASE) IN THE REACTOR BUILDING
- DBA NO. 2 DOES NOT CREATE A HARSH ENVIRONMENT IN THE TURBINE BUILDING
- PSC HAS AGREED TO ENVIRONMENTALLY QUALIFY THE DBA NO. 2 EQUIPMENT IN THE REACTOR BUILDING THAT WILL EXPERIENCE THE DBA NO. 2 HARSH ENVIRONMENT
- DBA NO. 2 EQUIPMENT IN THE TURBINE BUILDING WILL NOT EXPERIENCE A HARSH ENVIRONMENT DURING A HELB
- DBA NO. 2 EQUIPMENT IN THE TURBINE BUILDING IS NOT REQUIRED TO RESPOND TO A HELB IN THE TURBINE BUILDING
- CURRENT NRC POSITION IS THAT DBA NO. 2 EQUIPMENT WHICH EXPERIENCES A HARSH ENVIRONMENT MUST BE ENVIRONMENTALLY QUALIFIED
- PSC IS PREPARING A 10CFR50.49 EXEMPTION REQUEST FOR DBA NO. 2 EQUIPMENT IN THE TURBINE BUILDING WHICH WILL NOT EXPERIENCE A HARSH ENVIRONMENT DURING THE ACCIDENT IN WHICH THE EQUIPMENT IS RELIED UPON

TABLE 1

SUMMARY OF OFF-SITE DOSES RESULTING FROM POSTULATED ACCIDENTS

ACCIDENT	LOCATION OF MAXIMUM DOSE	TOTAL DURATION DOSE (REM) WHOLE BODY	THYROID
Complete Loss of Forced Circulation Cooling - DBA No. 1	Low Population Zone Boundary (180 day)	3.7 x E-4	3.6 x E-2
Worst PCRV Penetration Failure (both closures of a steam generator penetration) - DBA No. 2	Exclusion Area Boundary (2 Hours)	2.5	17.4
"Maximum Credible Accident" (largest Potential PCRV leak rate)	Exclusion Area Boundary (2 Hours)	1.62 x E-1	8.8 x E-2
30 minutes to set circulator seals and 400 lbs leakage via PCRV penetration closures	Low Population Zone Boundary (30 day)	4 x E-4	2.1 x E-2
	Exclusion Area Boundary (2 Hours)	3.6 x E-3	1.5 x E-2
60 minutes to set circulator seals and 400 lbs/day leakage until entire primary coolant inventory is released	Low Population Zone Boundary (30 day)	8 x E-4	5.9 x E-2
	Exclusion Area Boundary (2 Hours)	5.4 x E-3	2.3 x E-2
10CFR100 Guidelines	Low Population Zone Boundary (Duration of Accident)	25	300
	Exclusion Area Boundary (2 Hours)	25	300

TECHNICAL SPECIFICATION UPGRADE

TECHNICAL SPECIFICATION UPGRADE PROGRAM

SCOPE

LIMITING CONDITIONS FOR OPERATION (LCOs) WILL IDENTIFY APPLICABLE OPERATING MODES, LIMITING CONDITIONS, AND ACTION STATEMENTS

LIMITING CONDITIONS FOR OPERATION (LCOs) WILL AGREE WITH FSAR

LIMITING CONDITIONS FOR OPERATION (LCOs) WILL CROSS REFERENCE SURVEILLANCE REQUIREMENTS (SRs) AND VICE VERSA

SURVEILLANCE REQUIREMENTS (SRs) WILL VERIFY COMPLIANCE WITH LIMITING CONDITIONS FOR OPERATION (LCOs)

STATEMENTS WILL BE UNAMBIGUOUS WITH A SINGULAR INTERPRETATION

TERMINOLOGY USED WILL BE DEFINED

TECHNICAL SPECIFICATIONS WILL BE SIMPLIFIED IF POSSIBLE

TECHNICAL SPECIFICATIONS WILL BE ACCURATE, COMPLETE, AND CONSISTENT WITH EXISTING DESIGN AND SAFETY ANALYSIS DOCUMENTATION

TECHNICAL SPECIFICATION UPGRADE PROGRAM

USE OF STANDARD TECHNICAL SPECIFICATIONS

NO PLANT BACKFITTING TO ADOPT STS REQUIREMENTS

OUTSIDE SCOPE OF PROGRAM TO CONSIDER LICENSING BASIS ISSUES IN AN EFFORT TO UTILIZE STS REQUIREMENTS

R&D EFFORTS OR ANALYTICAL INVESTIGATIONS ARE NOT BEING UNDERTAKEN SOLELY FOR THE PURPOSE OF DETERMINING HOW TO UTILIZE STS REQUIREMENTS

STS NUMBERING SYSTEM AND LCO/SR FORMAT IS BEING UTILIZED

RELEVANT STS DEFINITIONS ARE BEING ADOPTED

RELEVANT STS REQUIREMENTS ARE BEING ADOPTED

JUSTIFICATION IS NOT REQUIRED CONCERNING TREATMENT OF STS REQUIREMENTS

TECHNICAL SPECIFICATION UPGRADE PROGRAM

SCHEDULE

- DISCUSS TECHNICAL SPECIFICATION UPGRADE PROGRAM SCOPE WITH NRC ON NOVEMBER 28-29, 1984
- FINALIZED OVERALL PROGRAM SCHEDULE ON DECEMBER 14, 1984
- SUBMITTED INITIAL DRAFT OF UPGRADED TECHNICAL SPECIFICATIONS ON APRIL 1, 1985
- NRC/PSC MEETING ON JULY 22-26, 1985 TO RESOLVE NRC COMMENTS ON FIRST DRAFT AND ESTABLISH NRC AND PSC ACTION ITEMS
- SUBMITTED FINAL DRAFT OF UPGRADED TECHNICAL SPECIFICATIONS ON NOVEMBER 27, 1985
- SUBMIT PROPOSED LICENSE AMENDMENT REQUESTING NRC APPROVAL OF UPGRADED TECHNICAL SPECIFICATIONS 90 DAYS AFTER RECEIPT OF NRC COMMENTS ON FINAL DRAFT
- NRC APPROVE UPGRADED TECHNICAL SPECIFICATIONS SIX MONTHS PRIOR TO START OF FOURTH REFUELING
- IMPLEMENT UPGRADED TECHNICAL SPECIFICATIONS DURING FOURTH REFUELING OUTAGE

LWR VERSUS HTGR CHARACTERISTICS

LWR VERSUS HTGR CHARACTERISTICS

- BASED ON RECENT NRC DIRECTION, PSC IS OF THE CLEAR UNDERSTANDING THAT WE ARE REQUIRED TO COMPLY WITH ALL NRC REGULATIONS, POLICIES AND GUIDANCE UNLESS AND UNTIL AN EXEMPTION REQUEST IS APPROVED IN WRITING BY THE NRC.

PUBLIC UTILITY COMMISSION ISSUES (NOTES)

CONTINUING TECHNICAL SUPPORT FROM GA (NOTES)

HTGR DEVELOPMENT SUPPORT (NOTES)

TECHNICAL ISSUES

GAS CIRCULATOR ISSUES

RECENT OPERATIONAL EXPERIENCE

MAY 16, 1984

INITIAL CYCLE 4 CRITICALITY

JUNE, 1984

TURBINE GENERATOR ON LINE JUNE 12, 1984

JUNE 23, 1984, EVENT:

- SUDDEN PRESSURE RELAY FAILS ON 'A' 4160/480 TRANSFORMER
- RESULTS IN MOISTURE INGRESS AND REACTOR SCRAM
- SIX OF THIRTY-SEVEN CONTROL RODS FAIL TO AUTOMATICALLY INSERT
- COLD SHUTDOWN ACHIEVED EVEN WITH SIX RODS OUT
- RODS MANUALLY INSERTED WITHIN ABOUT 20 MINUTES

JULY, 1984

CONCEPTUAL DEVELOPMENT OF THE CONTROL ROD DRIVE REFURBISHMENT PROGRAM BEGINS

RECENT OPERATIONAL EXPERIENCE

SEPTEMBER, 1984

FAILURE OF CONTROL ROD CABLE - CHLORIDE STRESS CORROSION

NOVEMBER, 1984

RESERVE SHUTDOWN HOPPER DOES NOT FULLY DISCHARGE

DECISION TO REPLACE ALL RSD MATERIAL AND ALL CRD CABLES

DECEMBER, 1984 - MARCH, 1985

HELIUM CIRCULATOR 1A REMOVED FOR BEARING WATER INTERSPACE LEAK

DURING REPAIRS DETERMINE CHLORIDE STRESS CORROSION CRACKING ON BOLTING

DECISION TO REFURBISH BOLTING ON ALL FOUR CIRCULATORS

APRIL, 1985 - JUNE, 1985

REMAINING CIRCULATORS REMOVED, BOLTING REPLACED, AND REINSTALLED

COMPLETION OF CRD REFURBISHMENT PROGRAM

RECENT OPERATIONAL EXPERIENCE

JULY, 1985

NRC AUTHORIZES OPERATION TO 15% PENDING EQ QUESTION RESOLUTION

PLANT CRITICAL ON JULY 20, 1985

PLANT SHUTDOWN ON JULY 23, 1985, DUE TO MOISTURE - REMAINS SHUTDOWN FOR PRIMARY COOLANT CLEANUP

AUGUST, 1985

NRC ADVISES PSC TO REMAIN SHUTDOWN

PSC PROVIDES JUSTIFICATION FOR 8% OPERATION TO ASSIST IN PRIMARY COOLANT CLEANUP

SEPTEMBER, 1985

NRC AUTHORIZES OPERATION TO 8% POWER ON SEPTEMBER 30, 1985

PLANT CRITICAL ON SEPTEMBER 30, 1985

PSC SUBMITS EXTENSION REQUEST FOR EQ FROM 11/30/85 TO 5/31/86

RECENT OPERATIONAL EXPERIENCE

OCTOBER, 1985

PLANT OPERATES AT LESS THAN 8% THERMAL POWER

NOVEMBER, 1985

REACTOR SHUTDOWN FOR EQ WORK NOVEMBER 7, 1985

ON NOVEMBER 26, 1985, NRC AUTHORIZES OPERATION AT UP TO 35% FOR PERIOD 11/30/85 THROUGH 5/31/86, CONTINGENT UPON NRR APPROVAL OF SOME OUTSTANDING EQ ISSUES

FEBRUARY, 1986

NRR AUTHORIZATION FOR 35% POWER RECEIVED FEBRUARY 7, 1986

REACTOR CRITICAL 2/14/86

PLANT STATUS - 600, 4/2/86

REACTOR POWER: 12.3% (GAS BALANCE)

PRIMARY COOLANT FLOW: 39.7%

REACTOR DEW POINT: +32°F

AVERAGE CORE OUTLET TEMPERATURE: 719°F

AVERAGE CORE INLET TEMPERATURE: 490°F

AVERAGE FUEL TEMPERATURE: 683°F

AGENDA

APRIL 2, 1986

8:30 am I. OPENING STATEMENT----------------------------C. P. Siess, ACRS

8:35 am II. INTRODUCTION ---------------------------------R. F. Walker, PSC

8:45 am III. A. Report By NRC/NRR -----------------------K. Heitner, NRR

B. Status of Major Licensing Issues (10CFR50 Appendix R, 10CFR50.49, etc.)

9:15 am IV. LICENSEE PERFORMANCE -----------------J. Jaudon, NRC Region IV

A. Inspection Results

B. Enforcement Actions

10:00 am V. PSC ADMINISTRATIVE AND MANAGEMENT ITEMS ----------------------R. F. Walker, PSC

A. Performance Enhancement Program -----------H. L. Brey, PSC

B. Status of Plant Operations-----------------J. W. Gahm, PSC

C. Status of Regulatory Issues -------------M. H. Holmes, PSC

1. Fire Protection (Appendix R)

2. Equipment Qualification

12:30 pm LUNCH

1:00 pm

3. Technical Specification Upgrade

4. LWR versus HTGR Characteristics

D. Public Utility Commission Issues---------R. F. Walker, PSC

E. Continuing Technical Support-------------R. F. Walker, PSC From GA

F. HTGR Development Support-----------------R. F. Walker, PSC

1. Gas Cooled Reactor Associates

2. Department of Energy

AGENDA

2:30 pm VI. TECHNICAL ISSUES ------------------------D. W. Warembourg, PSC

A. Gas Circulator Issues

1. Moisture Ingress Control -------D. W. Warembourg, PSC

2. Bolting Failures ---------------D. W. Warembourg, PSC

3. Future Gas Circulator-----------------H. L. Brey, PSC
Development

B. Control Rod Drive System

1. Failures, Overhaul,---------------F. J. Novachek, PSC
Modifications and Maintenance

2. Back EMF Technique ------------------R. L. Craun, PSC
to Evaluate Control Rod
Drive Performance

3. Reserve Shutdown Material----------L. M. McBride, PSC
Changeout

5:00 pm RECESS

APRIL 3, 1986

8:30 am C. PCRV Tendon Corrosion --------------------R. L. Craun, PSC
Problems and Corrective
Actions

D. Equipment Qualification ----------------M. E. Niehoff, PSC

E. Steam Generator Tube---------------------M. H. Holmes, PSC
Integrity (NUREG-0844)

F. Masonry Block Walls --------------------M. E. Niehoff, PSC

G. Human Factors Related to----------------M. E. Niehoff, PSC
Operations in Hostile
Environments (Ice Vests, etc.)

H. Fire Protection Actions -----------------F. W. Tilson, PSC
(Appendix R)

I. OTHERS (As May Be Identified
By ACRS Members At the Time
of the Meeting)

12:30 pm VII. SUMMATION

1:00 pm ADJOURN

2:00 pm PLANT TOUR

OPENING STATEMENT (NOTES)

INTRODUCTION (NOTES)

REPORT BY NRC/NRR (NOTES)

STATUS OF M R LICENSING ISSUES (NOTES)

<u>INSPECTION RESULTS (NOTES)</u>

ENFORCEMENT ACTIONS (NOTES)

STATUS OF PLANT OPERATIONS

PERFORMANCE ENHANCEMENT

PROGRAM

MISSION:

TO ASSIGN AND IMPLEMENT ACTIVITIES THAT WILL IMPROVE THE OVERALL QUALITY, MANAGEMENT AND OPERATION OF PUBLIC SERVICE NUCLEAR ORGANIZATION IN A CONTROLLED, TIMELY MANNER.

SEVEN MAJOR PROJECTS
PROJECT I - ORGANIZATIONAL CONCERNS

PURPOSE IS TO UNDERTAKE ACTIONS WHICH WILL ENHANCE AND STRENGTHEN THE GENERAL NUCLEAR ORGANIZATION AND ITS OVERALL METHODS OF CONDUCTING BUSINESS.

MAJOR ITEMS IN THIS PROJECT INCLUDE:

* NUCLEAR OGRANIZATIONAL CHANGES
* DEVELOPMENT OF CHARTERS AND MISSION STATEMENTS
* IMPLEMENTATION OF COMMUNICATIONS POLICIES
* EVALUATION OF PERSONNEL RETENTION
* APPROVAL OF 78 NEW MEMBERS TO THE NUCLEAR STAFF

PROJECT II - PLANNING AND SCHEDULING

PURPOSE IS TO ESTABLISH A MASTER PLANNING AND SCHEDULING FUNCTION TO PROVIDE SENIOR MANAGEMENT WITH A STRONG MECHANISM TO PRIORITIZE PROJECTS, ALLOCATE RESOURCES AND MONITOR STATUS AND SCHEDULE OF EACH PROJECT

FUNCTIONS ADDRESSED INCLUDE:

* DEVELOP MASTER PLANNING AND SCHEDULING FUNCTION
* IMPLEMENT DIVISIONAL PLANNING AND SCHEDULING FUNCTIONS
* DEVELOP OUTAGE AND LONG RANGE SCHEDULES
* IMPROVE PROJECT MANAGEMENT TECHNIQUES

PROJECT III - PREVENTIVE MAINTENANCE

PURPOSE IS TO ESTABLISH AN IMPROVED PREVENTIVE MAINTENANCE PROGRAM AND ORGANIZATION.

FUNCTIONS ADDRESSED INCLUDE:

* ESTABLISH A MAINTENANCE PLANNING ORGANIZATION
* REVISE EXISTING PM PROCEDURES
    - ADD PROCEDURES FOR CRITICAL COMPONENTS
    - IMPLEMENT POST MAINTENANCE TESTING PROCEDURES
* ADD A PROJECT TO EVALUATE THE DAVIS-BESSE EVENT

PROJECT IV - UPGRADE NUCLEAR POLICIES AND PROCEDURES

PURPOSE IS TO DEVELOP NEW OR REVISE EXISTING NUCLEAR RELATED PROCEDURES.

MAJOR ITEMS IN THIS PROJECT INCLUDE REVISION OF THE FOLLOWING DOCUMENTS:

* SYSTEM OPERATING PROCEDURES
* DESIGN RELATED PROCEDURES
* I&C CALIBRATION PROCEDURES
* MOST LEVEL I PROCEDURES
* COMMITMENT CONTROL PROGRAM
* EMERGENCY PROCEDURES

PROJECT V - TRAINING

PURPOSE IS TO SIGNIFICANTLY IMPROVE NUCLEAR RELATED TRAINING FOR ALL PERSONNEL ASSOCIATED WITH FORT ST. VRAIN.

FUNCTIONS ADDRESSED INCLUDE:

* INPO ACCREDITATION OF OPERATOR POSITIONS
* INPO ACCREDITATION OF NON-OPERATOR POSITIONS BY LATE 1986
* INSTITUTION OF COMPREHENSIVE SUPPORT DIVISION TRAINING

PROJECT VI - PLANT CONDUCT OF OPERATIONS

PURPOSE IS TO CORRECT ROOT CAUSES OF PLANT DEFICIENCIES IN FACILITIES AND OPERATOR RESPONSES.

MAJOR FUNCTIONS ADDRESSED INCLUDE:

* REVISING AND STANDARDIZING EQUIPMENT AND PIPING IDENTIFICATION
* DEFINING PLANT MANAGEMENT RESPONSIBILITIES AND TOUR PROCEDURES
* EVALUATE PERSONNEL FACILITIES
* ESTABLISH A COMPONENT SHELF-LIFE PROGRAM

PROJECT VII - TOTAL RESPONSIBILITY MANAGEMENT

PURPOSE IS TO IMPROVE MORALE AND HUMAN PRODUCTIVITY THROUGH HUMAN RESOURCE MANAGEMENT.

FUNCTIONS ADDRESSED INCLUDE:

* IMPROVE MANAGERIAL COMPETENCE
* SUBSTANTIALLY INCREASE EMPLOYEE COMMITMENT TO COMPANY GOALS
* CREATE HIGH LEVEL OF COOPERATION AND TEAMWORK THROUGHOUT THE WHOLE PSC NUCLEAR ORGANIZATION

SUMMARY

* NOW NEARLY ONE YEAR INTO PEP PROGRAM
  - 16 OF 34 ORIGINAL SUB-PROJECTS ARE NOW COMPLETE
  - 17 OF 42 CURRENT SUB-PROJECTS HAVE BEEN COMPLETED
* EQ HAS IMPACTED PROGRESS PRIMARILY IN THE AREA OF MAINTENANCE PLANNING AND SCHEDULING
* SOME SCHEDULE SLIPPAGE DUE TO:
  - INCREASE IN PROJECT SCOPE
  - STAFFING AND RESOURCES
  - ADDITION OF NEW PROJECTS

INDEPENDENT AUDIT OF PEP

* S. M. STOLLER CORPORATION IN LATE 1985

  - AUDIT INDICATED GOOD PROGRESS:

  "WE CONCLUDE THAT THE PEP IS A WELL THOUGHT OUT AND WELL STRUCTURED PROGRAM. IF CARRIED THROUGH WITH A STRONG SENSE OF MANAGEMENT COMMITMENT, WHICH APPEARS TO BE PRESENT, ITS IMPLEMENTATION SHOULD IMPROVE THE CONDUCT OF NUCLEAR OPERATIONS SUBSTANTIALLY."

  - BUT:

  "WE ARE CONCERNED WITH SLIPS IN THE IMPLEMENTATION SCHEDULE. THESE, IF CORRECTED, DO NOT THREATEN THE OBJECTIVES OF THE PEP. HOWEVER, TO THE EXTENT THEY ARE DUE TO DELAYS IN HIRING THE ADDITIONAL STAFF REQUIRED, A PROBLEM AGGRAVATED BY EXCESSIVELY HIGH LOSS OF PEOPLE FROM THE NUCLEAR ORGANIZATION, THAT WOULD POTENTIALLY HAVE A SERIOUS IMPACT. PSC IS AWARE OF THE URGENCY TO ACT ON THE HUMAN RESOURCE ISSUE, AND HAS INITIATED A NUMBER OF MEASURES WHICH SHOULD IMPROVE THAT PARTICULAR SITUATION, AND SHOULD ALSO BENEFIT THE EFFECTIVENESS OF THE WORKING ORGANIZATION MORE GENERALLY."

PERFORMANCE ENHANCEMENT PROGRAM

PSC ADMINISTRATIVE AND MANAGEMENT ITEMS (NOTES)

AGENDA

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- TECHNICAL SPECIFICATION UPGRADE
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APPENDIX I - DESCRIPTION, FORT ST. VRAIN

APPENDIX II - OPERATIONAL HISTORY

PUBLIC SERVICE COMPANY OF COLORADO

FORT ST. VRAIN NUCLEAR GENERATING STATION

ACRS MEETING

April 2 and 3, 1986

PSC Participants:

R. F. Walker, President and Chief Executive Officer
J. W. Gahm, Manager, Nuclear Production
D. W. Warembourg, Manager, Nuclear Engineering
H. L. Brey, Manager, Nuclear Fuels and Licensing
M. H. Holmes, Nuclear Licnesing Manager
F. J. Novachek, Technical/Administrative Services Manager
L. M. McBride, Nuclear Fuels and Analysis Manager
M. E. Niehoff, Nuclear Engineering Design Manager
R. L. Craun, Nuclear Site Engineering Manager
F. W. Tilson, Nuclear Mechanical Projects Supervisor

MOISTURE INGRESS CONTROL

MOISTURE INGRESS

SUMMARY OF ACTIVITIES

THE FORT ST. VRAIN IMPROVEMENT COMMITTEE WAS FORMED BY R. F. WALKER ON OCTOBER 23, 1984.

IMPROVEMENT COMMITTEE PURPOSE:

FORMULATE AND REVIEW PROPOSED TECHNICAL IMPROVEMENTS TO ENHANCE THE OPERATION OF FORT ST. VRAIN. FINANCIAL OR REGULATORY ASPECTS OF POSSIBLE IMPROVEMENTS SHOULD NOT BE A PRIMARY CONSIDERATION. OUTSIDE EXPERTISE WILL BE UTILIZED AS NECESSARY TO PROVIDE TECHNICAL ASSISTANCE.

COMMITTEE MEMBERSHIP:

R. F. WALKER, CHAIRMAN
H. L. BREY
J. W. GAHM
L. W. SINGLETON
D. W. WAREMBOURG

MOISTURE INGRESS COMMITTEE DISSOLVED WITH ACTIONS ABSORBED BY THE IMPROVEMENT COMMITTEE.

MOISTURE INGRESS MITIGATING ACTIONS

IMPLEMENTED BY MOISTURE INGRESS COMMITTEE

- INDICATING LIGHTS HAVE BEEN INSTALLED IN THE CONTROL ROOM TO SHOW THE OPERATOR WHEN AN ACCUMULATOR HAS BEEN FIRED.

- A SEAL-IN CIRCUIT WAS ADDED TO INTERLOCK THE BACK-UP BEARING WATER -2 VALVES WITH THE NORMAL BEARING WATER SUPPLY VALVE AND TO REQUIRE RESET ACTION TO OPEN THE SUPPLY VALVE.

- EVALUATION OF THE ACCUMULATOR FIRING PROGRAM HAS BEEN COMPLETED AND FOUND TO BE SATISFACTORY.

- SYSTEM 21 INSTRUMENT CALIBRATION FREQUENCY HAS BEEN EVALUATED AND NECESSARY MODIFICATIONS MADE TO THESE PROCEDURES.

- THE SIZE OF THE DRAIN LINE FROM THE HIGH PRESSURE SEPARATOR HAS BEEN INCREASED TO HANDLE UP TO 20 GALLONS PER MINUTE FLOW RATE.

- THE DRAIN LINE FROM THE HIGH PRESSURE SEPARATOR HAS BEEN REROUTED INTO THE TOP OF THE BEARING WATER SURGE TANK RATHER THAN INTO THE MAIN DRAIN LINE.

- THE HELIUM WATER DRAIN LINE FROM THE CIRCULATOR TO THE HIGH PRESSURE SEPARATOR HAS BEEN MODIFIED TO ELIMINATE THE LOOP SEAL WHICH PREVIOUSLY EXISTED.

- A TRANSIENT IMPROVEMENT COMMITTEE HAS BEEN ESTABLISHED TO INVESTIGATE ALL SERIOUS PLANT TRANSIENTS AND TO RECOMMEND PLANT MODIFICATIONS WHICH MIGHT ELIMINATE FUTURE TRANSIENTS FROM SIMILAR CONDITIONS.

- A COMPUTERIZED SYSTEM 21 DATA ACQUISITION SYSTEM WAS DEVELOPED AND PLACED IN SERVICE TO PERMIT BETTER ANALYSIS OF PLANT TRANSIENTS. (THIS SYSTEM IS BEING EXPANDED AT THE PRESENT TIME).

- AS AN INTERIM MEASURE, VALVE OPENING BOOSTERS WERE INSTALLED ON THE EXISTING MAIN DRAIN PNEUMATIC VALVES.

- INSTALL NEW STRAINERS UPSTREAM OF BUBW FILTERS.

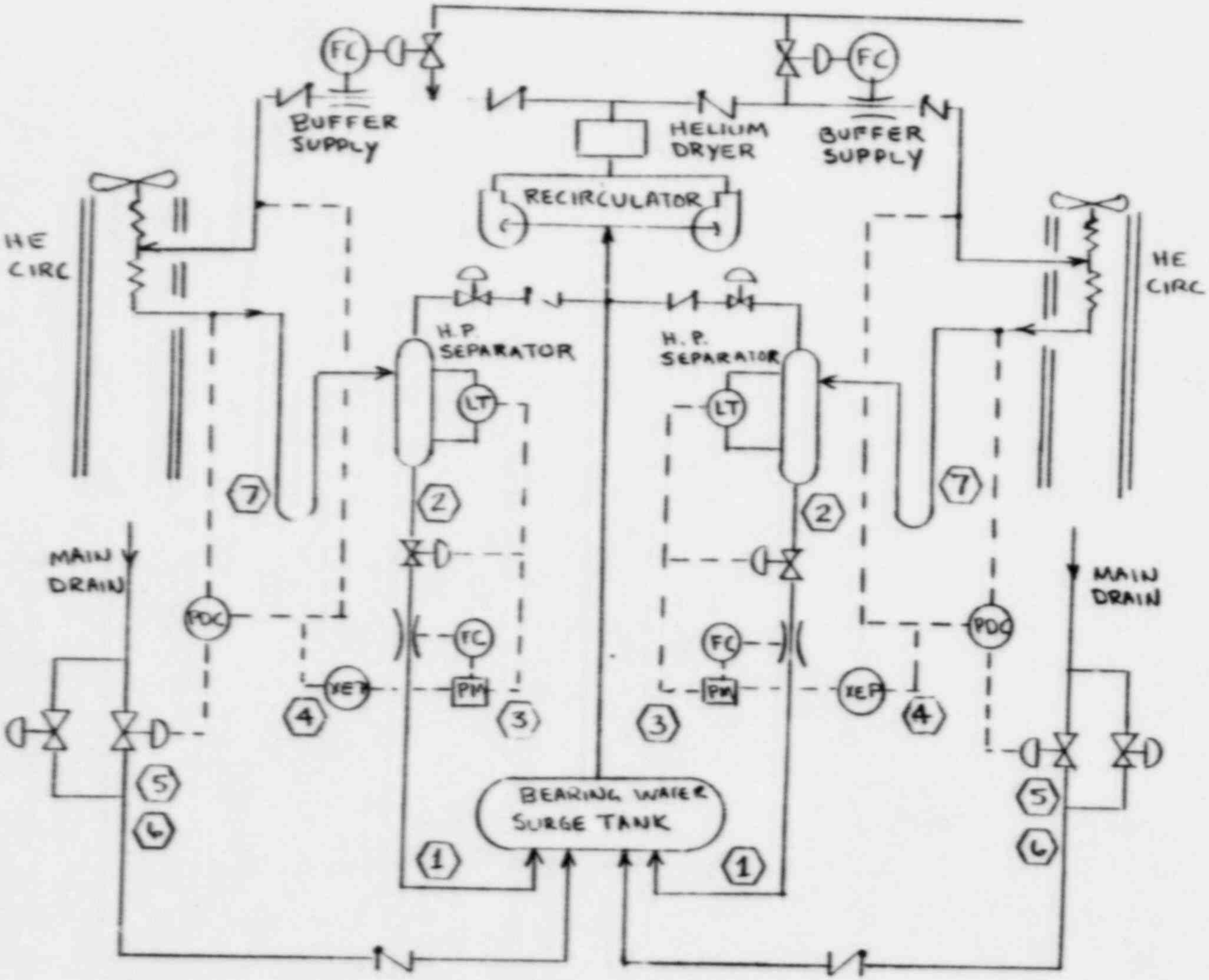
- INSTALL NEW POSITIONERS ON HIGH PRESSURE SEPARATOR DRAIN VALVES.

- REPLACE PRESSURE DIFFERENTIAL INSTRUMENT CABLES WITH SHIELDED CABLE.

- INSTALL ELECTRONIC CONTROLS FOR MAIN DRAIN VALVES.

- REPLACE BARTON LEVEL INDICATION SYSTEM ON BUFFER HELIUM RECIRCULATORS.

- COMPLETE AND ISSUE A MOISTURE INGRESS MANUAL.



1. Relocate High Pressure Separator Drain to Top of Bearing Water Surge Tank.
2. Increase Drain Line From High Pressure Separator to Handle 20 GPM.
3. Eliminate LT and FC Feedback to Main Drain.
4. Control High Pressure Separator Level Independently.
5. Control Main Drain on Cartridge ΔP Only. Use 1" Bypass Valve For Control. Consider Electronic Controls For Fast Action.
6. Main Drain Must Have Fast Opening Response.
7. Eliminate Loop Seal to High Pressure Separator.

MODIFICATIONS PROPOSED TO MITIGATE MOISTURE INGRESS

ITEMS INVESTIGATED BY MOISTURE INGRESS COMMITTEE AND REJECTED

SUGGESTION	ACTION
PAIR A & C CIRCULATORS AND B & D CIRCULATORS TO REDUCE RISK OF LOSING TWO CIRCULATORS IN A LOOP.	WOULD REPRESENT SIGNIFICANT CHANGES TO CONTROL SYSTEMS. SEPARATION/SEGREGATION/FIRE PROTECTION ISSUES SERIOUSLY IMPACTED. CHANGE NOT EFFECTIVE FOR OTHER MOISTURE INGRESS SITUATIONS, RECOMMENDATION REJECTED.
PROVIDE HIGH PRESSURE SEPARATOR TO BUFFER SUPPLY DIFFERENTIAL PRESSURE INDICATION TO THE CONTROL ROOM.	CHANGE NOT PHYSICALLY FEASIBLE DUE TO CHECK VALVES IN CIRCULATOR CARTRIDGE. EXISTING DIFFERENTIAL PRESSURE INDICATION BETWEEN PURIFIED HELIUM HEADER AND BEARING WATER SURGE TANK SHOULD PROVIDE ADEQUATE CONTROL ROOM INDICATION.
INVESTIGATE UTILIZING THE SMALL BY-PASS VALVE AROUND THE MAIN DRAIN VALVE FOR CONTROL TO IMPROVE SYSTEM RESPONSE.	COMPUTERIZED SIMULATION ANALYSIS COMPLETED. USE OF SMALL VALVE DEGRADES DRAIN AND CONTROL SYSTEM. NO FURTHER ACTION TAKEN.

ITEMS INVESTIGATED BY
MOISTURE INGRESS COMMITTEE
AND REJECTED

SUGGESTION	ACTION
REPLACE MAIN DRAIN VALVE WITH A HYDRAULIC VALVE.	HYDRAULIC VALVES HAVE PROVEN TO BE VERY TROUBLESOME. A DIGITAL VALVE IS BEING INVESTIGATED. SUGGESTION REJECTED.
MODIFY SYSTEM TO RUN FOR A PERIOD OF TIME WITHOUT THE BUFFER HELIUM RECIRCULATOR.	THIS SUGGESTION WAS REJECTED. ADDITIONAL CONTROL SYSTEM REQUIREMENTS AND POSSIBLE BUFFER HELIUM UPSETS SERVE TO COMPLICATE RATHER THAN IMPROVE THE SYSTEM.

ITEMS BEING CONSIDERED BY THE MOISTURE INGRESS COMMITTEE WHICH WERE TURNED OVER TO THE IMPROVEMENT COMMITTEE

ITEM	STATUS
REMOVE TRIP INHIBIT FOR SECOND CIRCULATOR IN A LOOP.	PRESENTLY UNDER EVALUATION.
INSTALL A MOISTURE SLINGER ON THE SHAFT OF THE HELIUM CIRCULATORS TO CIRCUMVENT LARGE QUANTITIES OF WATER FROM GOING UP THE SHAFT.	INVESTIGATIONS WERE COMPLETED. WOULD REQUIRE MAJOR MODIFICATIONS TO THE CIRCULATOR CARTRIDGES. WOULD ONLY BE EFFECTIVE WHEN CIRCULATOR IS OPERATING AT RELATIVELY HIGH SPEED. MAY BE WORTH CONSIDERING IF OTHER CARTRIDGE MODIFICATIONS WERE TO BE MADE.
INSTALL DIGITAL VALVES IN MAIN DRAIN LINE TO REPLACE EXISTING VALVES ALONG WITH ELECTRONIC CONTROLS FOR BETTER CONTROL RESPONSE.	A DIGITAL VALVE WAS INSTALLED ON ONE CIRCULATOR FOR TESTING PURPOSES. THE VALVE BOUND-UP AND DID NOT FUNCTION PROPERLY. THE VALVE WAS REMOVED AND RETURNED TO THE VENDOR FOR FURTHER ENGINEERING EVALUATIONS. ELECTRONIC CONTROLS WERE INSTALLED AND ARE IN USE.

ITEMS BEING CONSIDERED
BY THE MOISTURE INGRESS COMMITTEE
WHICH WERE TURNED OVER TO THE
IMPROVEMENT COMMITTEE

ITEM	STATUS
MODIFY CONTROL SYSTEM FOR HIGH PRESSURE SEPARATOR AND MAIN DRAIN.	THE ELECTRONIC CONTROL SYSTEM THAT WAS INSTALLED PROVIDES FOR CONTROL EITHER FROM CARTRIDGE DIFFERENTIAL PRESSURE OR WITH HIGH PRESSURE SEPARATOR FEED BACK.
REPLACE BUFFER HELIUM RECIRCULATOR WITH AN EDUCTOR.	EVALUATIONS INDICATE THAT THIS MAY HAVE SOME ADVANTAGES, BUT ONLY WHEN COMBINED WITH OTHER CHANGES.
REPLACE MAIN DRAIN WITH A FIXED ORIFICE DRAIN SYSTEM WITH ASSISTANCE TO HIGH PRESSURE SEPARATOR DRAINS BEING PROVIDED WITH A JET PUMP.	EVALUATIONS INDICATE THAT WITHOUT OTHER CHANGES A FIXED ORIFICE DRAIN SYSTEM WILL NOT FUNCTION ADEQUATELY FOR ALL MODES OF CIRCULATOR OPERATION. (I.E., START-UP, SELF-TURBINING, AND STEADY STATE).
INSTALL FULL FLOW OR BY-PASS FLOW FILTERS IN BEARING WATER SUPPLY LINES.	CURRENTLY BEING EVALUATED.

ITEMS BEING CONSIDERED BY THE MOISTURE INGRESS COMMITTEE WHICH WERE TURNED OVER TO THE IMPROVEMENT COMMITTEE

ITEM	STATUS
EVALUATE USE OF DIGITAL VALVES FOR BEARING WATER. BACK-UP BEARING WATER SUPPLY.	GIVEN EXPERIENCE TO DATE WITH DIGITAL VALVES, THIS ITEM IS ON THE BACK BURNER UNTIL VENDOR EVALUATIONS OF DIGITAL VALVE DESIGN IS COMPLETED.
REPLACE LAMINAR FLOW ELEMENTS IN BUFFER SUPPLY LINES.	A RESISTANCE DIFFERENTIAL TEMPERATURE TYPE METER WAS ORDERED AND INSTALLED ON A TEST BASIS ("D" CIRCULATOR SUPPLY). ADEQUATE CONTROL SYSTEM COORDINATION COULD NOT BE OBTAINED DURING TESTS. THE METER HAS BEEN REMOVED. FURTHER ENGINEERING ANALYSES ARE IN PROGRESS.
REPLACE THREE (3) HALF CAPACITY BEARING WATER PUMPS WITH FULL CAPACITY PUMPS.	EVALUATIONS INDICATE THAT THE EMERGENCY DIESEL GENERATORS ARE NOT ADEQUATE TO PICK UP THE INCREASED LOAD. NO FURTHER ACTION ANTICIPATED.

ITEMS BEING CONSIDERED
BY THE MOISTURE INGRESS COMMITTEE
WHICH WERE TURNED OVER TO THE
IMPROVEMENT COMMITTEE

ITEM	STATUS
ELIMINATE CIRCULATOR TRIP ON POSITIVE BUFFER-MID-BUFFER (PRIMARY COOLANT FLOWING DOWN THE SHAFT).	EVALUATIONS IN PROGRESS. RESULTS IN PRIMARY COOLANT BEING RELEASED TO THE REACTOR BUILDING AND SUBSEQUENTLY TO THE ENVIRONMENT.

MOISTURE INGRESS

CURRENT ISSUES

IMPROVEMENT COMMITTEE

ITEM	STATUS
FLOAT BEARING WATER PRESSURE WITH PCRV PRESSURE.	EVALUATIONS HAVE NOT YET STARTED ON THIS ITEM.
ADD AN UNINTERRUPTIBLE POWER SUPPLY FOR CRITICAL SYSTEM 21 COMPONENTS.	MODIFICATIONS WERE MADE WHERE POSSIBLE AND PORTABLE BATTERY PACKS WERE PROVIDED IN OTHER AREAS TO ENSURE AN UNINTERRUPTIBLE POWER SUPPLY.
INVESTIGATE/EVALUATE UTILIZING A HYDROSTATIS SEAL IN LIEU OF THE UPPER LABYRINTH STATIC HELIUM SEALS.	A PRELIMINARY ENGINEERING EVALUATION HAS BEEN COMPLETED BY WESTINGHOUSE. PRESENTLY BEING EVALUATED BY PSC ENGINEERING.
EVALUATE MODIFYING THE HELIUM CIRCULATOR LOWER WATER DRAINS.	EVALUATION INDICATES THAT A STRAIGHT FORWARD MODIFICATION CAN BE MADE WHICH WILL REDUCE THE AMOUNT OF WATER THAT NEEDS TO BE HANDLED IN THE LOWER DRAIN AREA. THIS MODIFICATION WILL BE CONSIDERED IN THE FUTURE AS CIRCULATORS ARE REFURBISHED.

MOISTURE INGRESS

CURRENT ISSUES

IMPROVEMENT COMMITTEE

ITEM	STATUS
REVISE THE I-02 CONTROL BOARD IN THE CONTROL ROOM TO IMPROVE OPERATOR/CONTROL INTERFACE.	REVISIONS OF THE CONTROL PANELS HAVE BEEN DESIGNED AS A PART OF THE CRDR PROJECT.
INVESTIGATE POSSIBILITY OF INSTALLING MOTOR DRIVEN, HERMETICALLY SEALED, MAGNETIC BEARING CIRCULATORS.	A PROPOSAL HAS BEEN DEVELOPED AND PRESENTED TO THE COMMITTEE. THIS PROPOSAL WILL BE CONSIDERED ALONG WITH THE VARIOUS OTHER ALTERNATIVES. ECONOMIC EVALUATIONS BEING PREPARED. EPRI INVOLVEMENT TO BE PURSUED.
INVESTIGATE THE POSSIBILITY OF INSTALLING MOTOR DRIVEN OIL BEARING CIRCULATOR.	NOT A LEADING CONCEPT. NO WORK BEING DONE CURRENTLY.
INVESTIGATE/EVALUATE THE POSSIBILITY UTILIZING HELIUM CIRCULATORS WITH MAGNETIC BEARINGS BUT RETAIN STEAM WATER DRIVE.	INITIAL ENGINEERING WORK HAS BEEN RELEASED TO PROTO POWER CORPORATION UNDER A JOINT EPRI/PSC PROGRAM.

MOISTURE INGRESS

CURRENT ISSUES

IMPROVEMENT COMMITTEE

ITEM	STATUS
INVESTIGATE/EVALUATE SYSTEM MODIFICATIONS THAT PERMIT MAXIMUM USE OF EXISTING CIRCULATORS.	GA HAS SUBMITTED A PROPOSAL WHICH IS CURRENTLY UNDER EVALUATION. THIS PROPOSAL INCORPORATES THE FIXED ORIFICE DRAIN, EDUCTORS, JET PUMPS, MODULARIZED AUXILIARY UNITS, COMPLETE CIRCULATOR INDEPENDENCE, WITH THE OBJECTIVE OF ELIMINATING BACK-UP BEARING WATER, AND ACCUMULATORS AND PROVIDING A MORE PASSIVE CIRCULATOR AUXILIARY SYSTEM.
EVALUATE SYSTEM 23 (HELIUM PURIFICATION SYSTEM) FOR POSSIBLE IMPROVEMENTS IN CAPACITY.	CHILLED WATER UNITS HAVE BEEN INSTALLED ON THE FRONT-END COOLER. OPERATIONAL EXPERIENCE PRESENTLY BEING EVALUATED.
DEVELOP BETTER OPERATOR TRAINING WITH SIMULATOR CAPABILITIES.	PORTIONS OF THE HELIUM CIRCULATOR AUXILIARIES HAVE BEEN PUT INTO A SIMULATOR DEVELOPED BY PSC. SYSTEM OPERATING PROCEDURES HAVE BEEN REWRITTEN.

BOLTING FAILURES

HELIUM CIRCULATOR

BOLTING

PROBLEM IDENTIFICATION

CIRCULATOR C-2104 WAS REMOVED IN JANUARY 1984 AND SENT BACK TO GA FOR REBURBISHMENT.

CIRCULATOR C-2102, WHICH HAD BEEN REFURBISHED PREVIOUSLY AT GA WAS UTILIZED TO REPLACE C-2104.

SUBSEQUENTLY, A BEARING WATER LEAK WAS FOUND IN C-2102. THIS CIRCULATOR WAS REMOVED FROM FORT ST. VRAIN AND SENT BACK TO GA IN DECEMBER 1984. (A FLANGE BOLT ON THE BEARING WATER SUPPLY SIDE HAD FAILED DUE TO A MANUFACTURING DEFECT).

C-2104 WAS NOT YET REFURBISHED. FASTER TURNAROUND COULD BE REALIZED IN THE REPAIR OF C-2102.

IN THE REASSEMBLY PROCESS OF C-2102, ONE OF THE TWENTY-FOUR (24) HIGH STRENGTH PRIMARY CLOSURE BOLTS (300-40) FAILED DURING TORQUING OPERATIONS.

SUBSEQUENT EVALUATIONS WERE MADE AND IT WAS DETERMINED THAT THE FAILURE RESULTED FROM STRESS CORROSION CRACKING.

IMMEDIATE ACTION WAS TAKEN TO IDENTIFY ALL HIGH STRENGTH BOLTING WITHIN THE CIRCULATOR AND TO DEVELOP AN OVERALL TESTING/EVALUATION PROGRAM.

PRODUCTION HELIUM CIRCULATOR ASSEMBLY

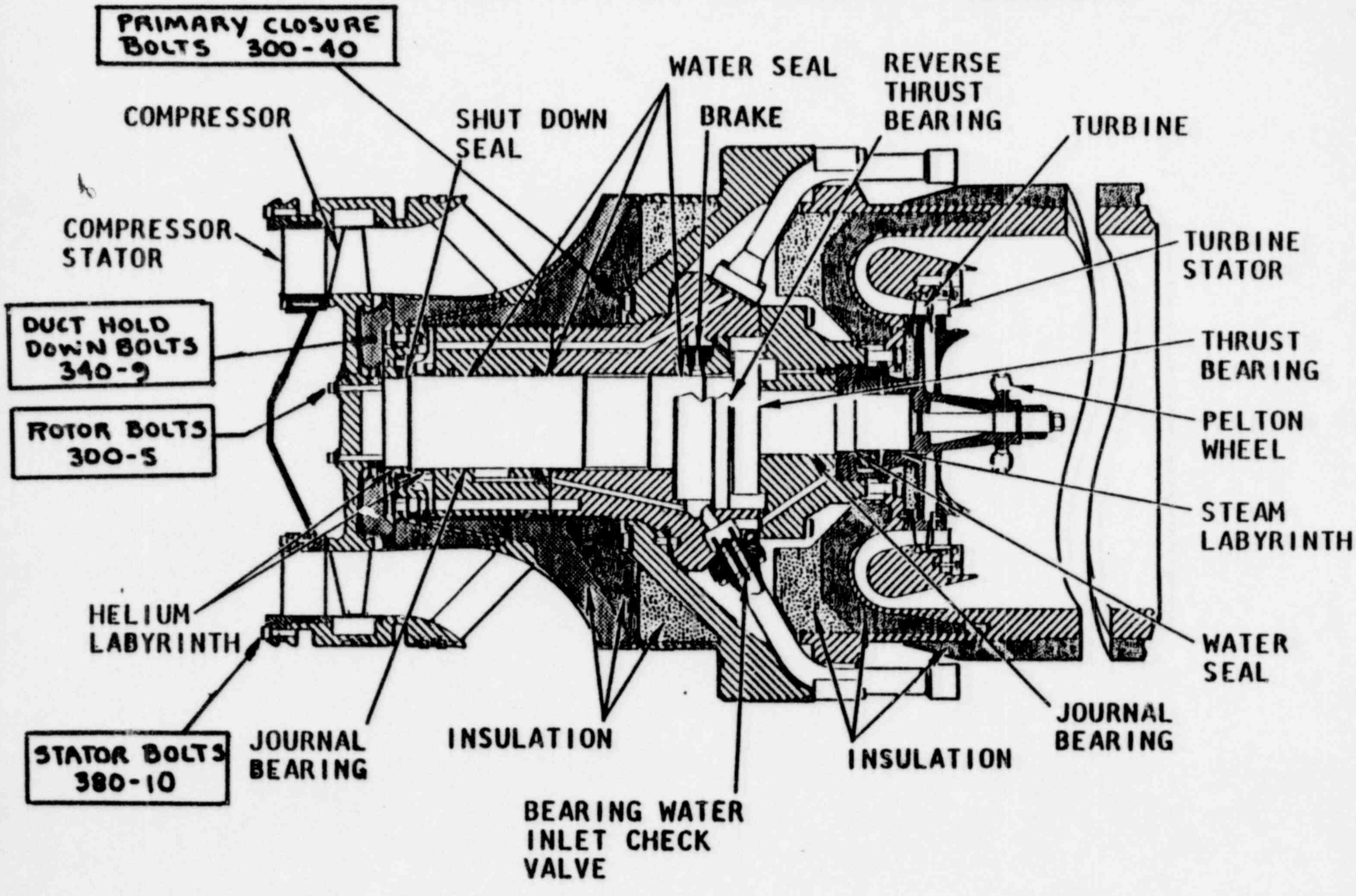


FIGURE 1

HELIUM CIRCULATOR BOLTING

IN CONTACT WITH PRIMARY COOLANT

PRIMARY CLOSURE BOLTS 300-40

MATERIAL	H-11 HIGH STRENGTH FERRITIC, CD PLATED
PROPERTIES	260,000 ULTIMATE; 215,000 YIELD
NUMBER OF BOLTS	24 BOLT CIRCLE
SIZE	3/4" ø

STATOR BOLTS 380-10

MATERIAL	A-286 PRECIPITATION HARDENED AUSTENITIC STAINLESS STEEL, SILVER PLATED
PROPERTIES	135,000 - 160,000 ULTIMATE 65,000 - 115,000 YIELD
NUMBER OF BOLTS	12 BOLT CIRLCE
SIZE	7/16" ø

(SEE FIGURE 1 FOR LOCATIONS)

HELIUM CIRCULATOR BOLTING

IN CONTACT WITH PRIMARY COOLANT

DUCT HOLD DOWN BOLTS 340-9

MATERIAL	A-286
PROPERTIES	135,000 - 160,000 ULTIMATE 65,000 - 115,000 YIELD
NUMBER OF BOLTS	12 BOLT CIRCLE
SIZE	5/8" ø

ROTOR BOLTS 300-5

MATERIAL	INCONEL 718
PROPERTIES	185,000 ULTIMATE 150,000 YIELD
NUMBER OF BOLTS	8 BOLT CIRCLE
SIZE	3/8" ø

(SEE FIGURE 1 FOR LOCATIONS)

HELIUM CIRCULATOR

BOLTING INSPECTION

AFTER INITIAL INSPECTIONS (C-2102 AND C-2104), THE INCONEL 718 ROTOR BOLTS WERE ELIMINATED FROM FURTHER INSPECTION.

FOR THE REMAINING THREE AREAS (H-11 AND A-286 BOLTING), THE FOLLOWING INSPECTIONS WERE MADE FOR ALL FIVE CIRCULATORS:

* ALL BOLTING WAS VISUALLY INSPECTED. ADDITIONAL BOLTING WAS EXAMINED UTILIZING FLUORESCENT LIQUID PENETRANT.

* BOLTING FROM EACH OF THE THREE AREAS WAS SELECTED AT RANDOM FOR METALLURGICAL INVESTIGATIONS. BOLTS WERE SECTIONED AND EXAMINED MACROSCOPICALLY AND MICROSCOPICALLY.

* RANDOMLY SELECTED BOLTING WAS LEACHED IN DEMINERALIZED WATER AND ANALYZED FOR CHLORIDES.

* MATERIAL CHEMISTRY WAS CONFIRMED AS MEETING APPROPRIATE STANDARDS FOR A SAMPLE OF BOLTING.

CIRCULATOR 2101					
BOLT IDENT	VISUAL/LIQ PENET		METALLURGICAL		RESULTS
	NO. BOLT	INDICATION	NO. BOLT	SCC	
PRIMARY CLOSURE 300-40 H-11	24	-0-	7	1	MINOR PITTING BUT NO DEFECTS IN 6 OF 7 BOLTS. ONE BOLT FAILED DURING REMOVAL AND EXHIBITED EXTENSIVE SCC.
STATOR HOLD DOWN 380-10 A-286	12	-0-	6	-0-*	SOME CRACKING OBSERVED IN THREADS OF 4 BOLTS. CRACKS WERE OLD AND MOST LIKELY OCCURRED IN ORIGINAL MANUFACTURER.
DUCT HOLD DOWN 340-9 A-286	12	-0-	6	-0-	NO DEFECTS FOUND.
ROTOR 300-5 INCONEL	NONE CHECKED	N/A	NONE CHECKED	N/A	N/A

SCC = STRESS CORROSION CRACKING

* CRACKING OBSERVED IN FOUR BOLTS BUT NO INDICATION THAT CRACKING WAS CAUSED BY SCC.

CHLORIDE ANALYSES INDICATED LEVELS SLIGHTLY OVER $2\times10^{-6} g/cm^2$.

ALL H-11 AND A-286 BOLTING REPLACED WITH INCONEL 718.

CIRCULATOR 2102					
BOLT IDENT	VISUAL/LIQ PENET		METALLURGICAL		RESULTS
	NO. BOLT	INDICATION	NO. BOLT	SCC	
PRIMARY CLOSURE 300-40 H-11	23	-0-	6	3	ONE BOLT FAILED IN TORQUING OPERATION. SCC FOUND IN ROOT OF TOP THREADS NOT ENGAGED.
STATOR HOLD DOWN 380-10 A-286	12	-0-	6	4*	CRACKING OBSERVED IN ROOT OF TOP THREE THREADS NOT ENGAGED.
DUCT HOLD DOWN 340-9 A-286	12	-0-	6	NONE	NO SCC OR FAILURES IDENTIFIED.
ROTOR 300-5 INCONEL	8	-0-	2	-0-	NO SCC OR FAILURES IDENTIFIED.

SCC = STRESS CORROSION CRACKING

THE HIGH STRENGTH H-11 PRIMARY CLOSURE BOLTS CRACKING RESULTED FROM STRESS CORROSION.

* THE A-286 CRACKING IN ALL PROBABILITY RESULTED FROM STRESS CORROSION BUT THE CAUSE OF CRACKING COULD NOT BE POSITIVELY DETERMINED.

CHLORIDE ANALYSES INDICATED $13 \times 10^{-6} g/cm^2$ MAXIMUM.

ALL H-11 AND A-286 BOLTING REPLACED WITH INCONEL 718.

CIRCULATOR 2103					
BOLT IDENT	VISUAL/LIQ PENET		METALLURGICAL		RESULTS
	NO.BOLT	INDICATION	NO.BOLT	SCC	
PRIMARY CLOSURE 300-40 H-11	24	-0-	6	1	SUPERFICIAL RUST NUMEROUS CRACKS IN THREAD TIPS ACCEPTABLE WITHIN FEDERAL SPECS. ONE SCC OBSERVED IN PARTIAL THREAD NEAR SHANK.
STATOR HOLD DOWN 380-10 A-286	12	-0-	6	-0-	NO DEFECTS FOUND
DUCT HOLD DOWN 340-9 A-286	12	-0-	6	-0-	NO DEFECTS FOUND
ROTOR 300-5 INCONEL	NONE CHECKED	N/A	NONE CHECKED	N/A	N/A

SCC= STRESS CORROSION CRACKING

CHLORIDE ANALYSES INDICATED 3×10^{-6}g/cm^2 MAXIMUM.

ALL H-11 AND A-286 BOLTING REPLACED WITH INCONEL 718.

CIRCULATOR 2104					
BOLT IDENT	VISUAL/LIQ PENET		METALLURGICAL		RESULTS
	NO. BOLT	INDICATION	NO. BOLT	SCC	
PRIMARY CLOSURE 300-40 H-11	24	-0-	6	NONE	NO FAILURES OR SCC WERE OBSERVED
STATOR HOLD DOWN 380-10 A-286	12	-0-	6	NONE	NO FAILURES OR SCC IDENTIFIED.
DUCT HOLD DOWN 340-9 A-286	12	-0-	2	NONE	NO FAILURES OR SCC IDENTIFIED
ROTOR 300-5 INCONEL	8	-0-	2	NONE	NO FAILURES OR SCC IDENTIFIED.

SCC = STRESS CORROSION CRACKING

CHLORIDE ANALYSES INDICATED $24 \times 10^{-6} g/cm^2$ MAXIMUM.

ALL H-11 AND A-286 BOLTING REPLACED WITH INCONEL 718.

CIRCULATOR 2105					
BOLT IDENT	VISUAL/LIQ PENET		METALLURGICAL		RESULTS
	NO. BOLT	INDICATION	NO. BOLT	SCC	
PRIMARY CLOSURE 300-40 H-11	24	-0-	6	2	RUST AND MINOR PITTING. SCC OBSERVED IN THE HEADS OF TWO BOLTS. DETERMINED TO BE OLD CRACKS.
STATOR HOLD DOWN 380-10 A-286	12	-0-	6	-0-	NO SCC OR OTHER CRACKING OBSERVED.
DUCT HOLD DOWN 340-9 A-286	12	-0-	6	-0-	NO SCC OR OTHER CRACKING OBSERVED.
ROTOR 300-5 INCONEL	NONE CHECKED	N/A	NONE CHECKED	N/A	N/A

SCC = STRESS CORROSION CRACKING

CHLORIDE ANALYSES INDICATED $4\times10^{-6} g/cm^2$ MAXIMUM.

ALL H-11 AND A-286 BOLTING REPLACED WITH INCONEL 718.

CONCLUSIONS

SOME DEFECTS WERE MOST LIKELY ORIGINATED DURING MANUFACTURE AND ASSEMBLY.

SOME CRACKING WAS DEFINITELY CAUSED BY STRESS CORROSION.

CONDITIONS WERE PRESENT AT VARIOUS TIMES WITHIN THE FSV CORE WHICH COULD RESULT IN STRESS CORROSION (PRESENCE OF CHLORIDES, MOISTURE AND OXYGEN).

HIGH STRENGTH BOLTING IN CONTACT WITH PRIMARY COOLANT WAS REPLACED IN ALL FIVE CIRCULATORS.

A T T A C H M E N T S

TYPICAL METALLOGRAPY

R E S U L T S

CIRCULATOR C-2101

X100

Pitting in root of thread adjacent to fracture of primary closure bolt H11.

X100

Pitting and SCC in root of thread adjacent to the fracture of the primary closure bolt H11.

CIRCULATOR C-2101

X500

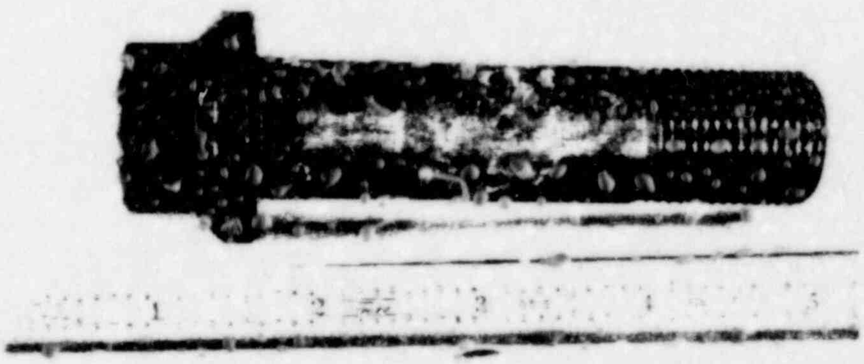
Root of first thread in the A286 stator bolt #4 shoing evidence of silver plating in crack.

X500

Root of first thread in the A286 stator bolt #7 showing evidence of silver plating in crack.

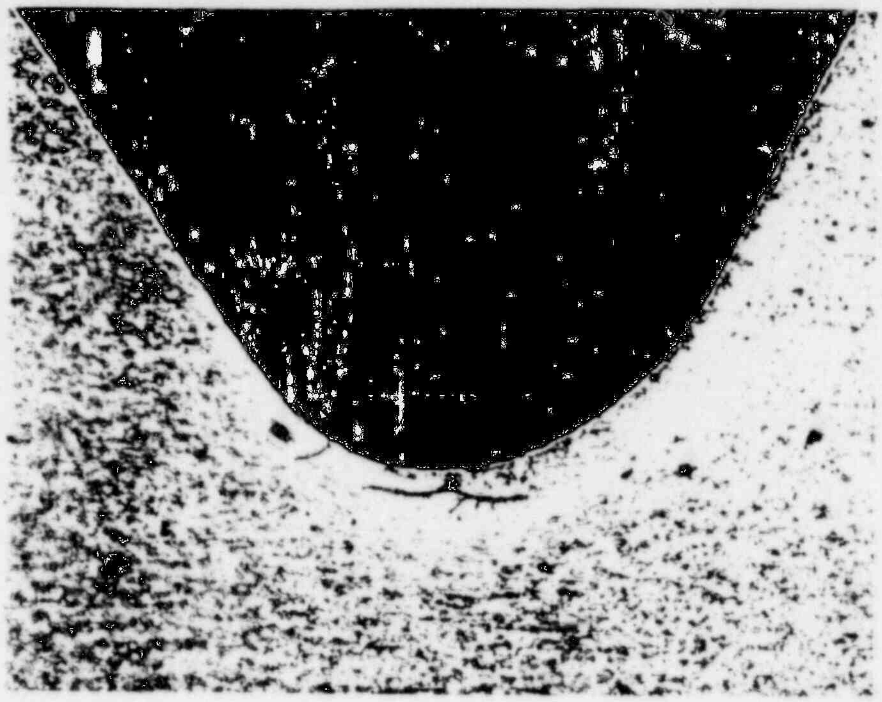
CIRCULATOR C-2102

Bolt 2102A As-Received condition

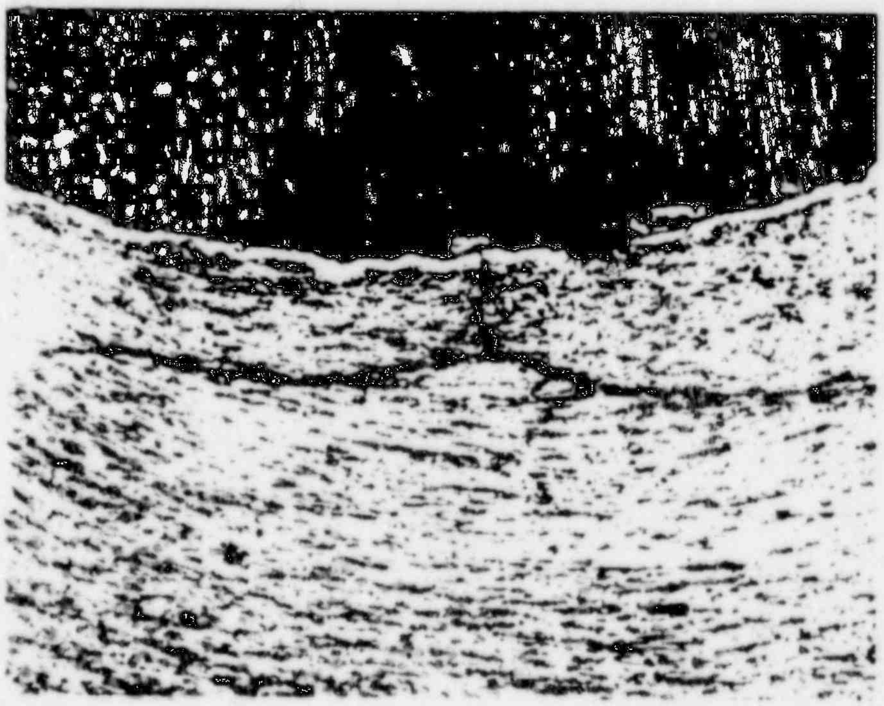


Bolt 2102B As-Received condition

CIRCULATOR C-2102

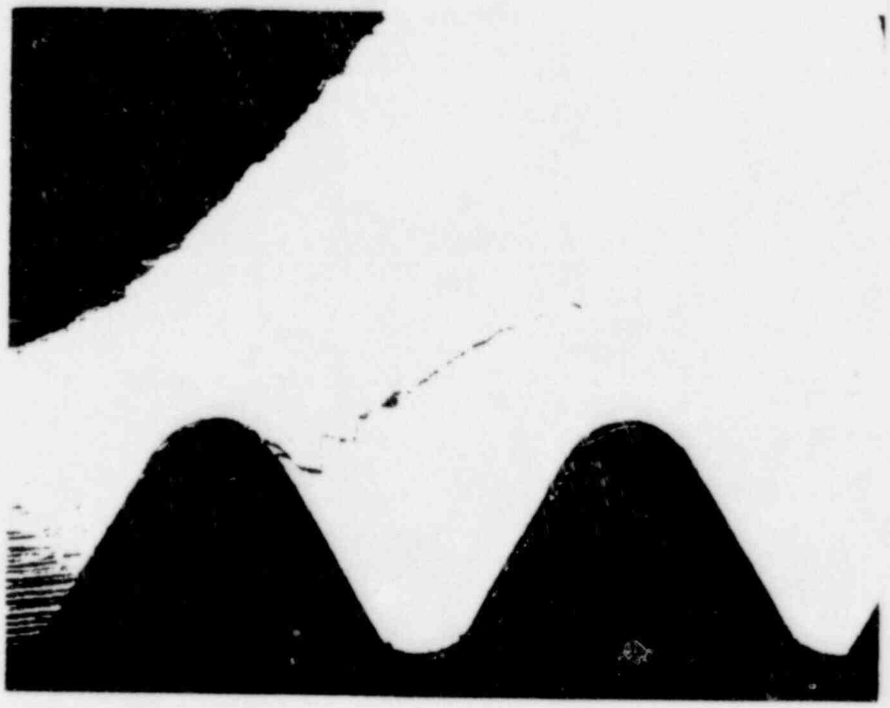


Bolt 2102B etched in 2% Nital showing cracks, 100X

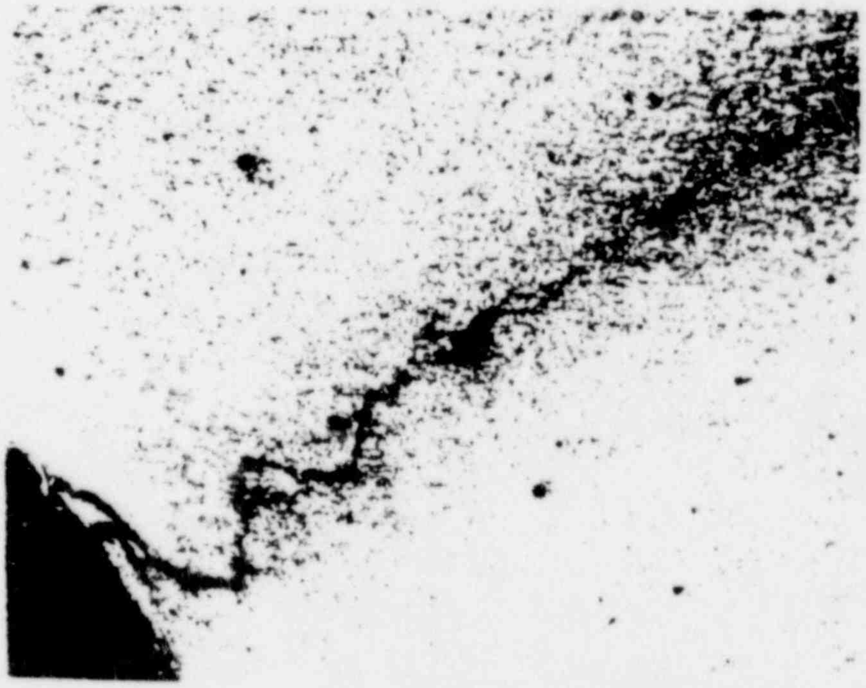


Bolts 2102B etched in 2% Nital--notice the break in the coating near the crack origin, 500X

CIRCULATOR C-2102



Secondary crack propagating parallel to failure face, 30X

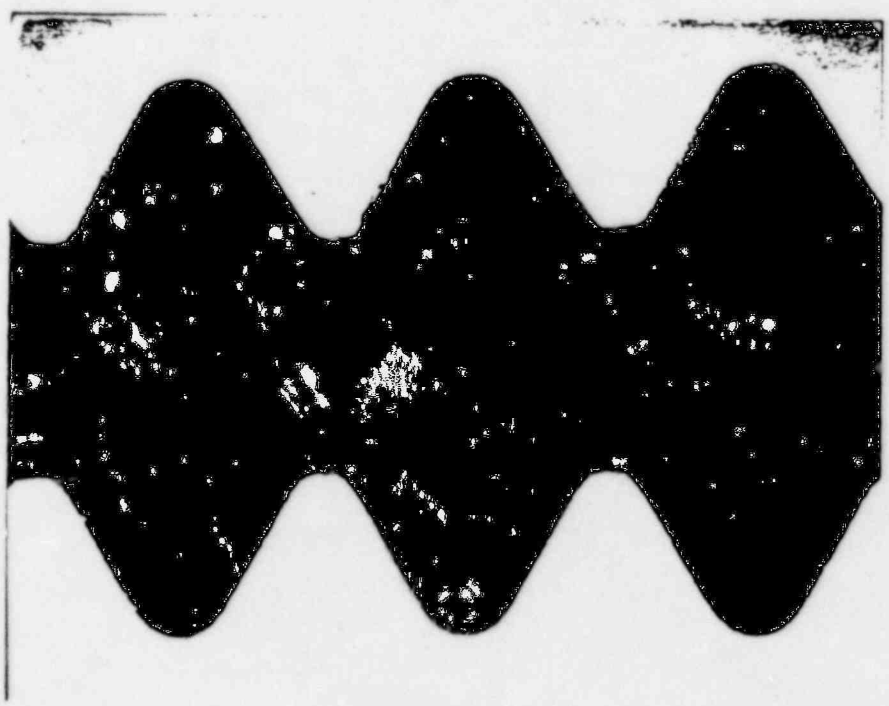


Secondary crack etched in 2% Nital, 100X

CIRCULATOR C-2103

X30

Typical X-section through H11 primary closure bolt - circultor 2103.



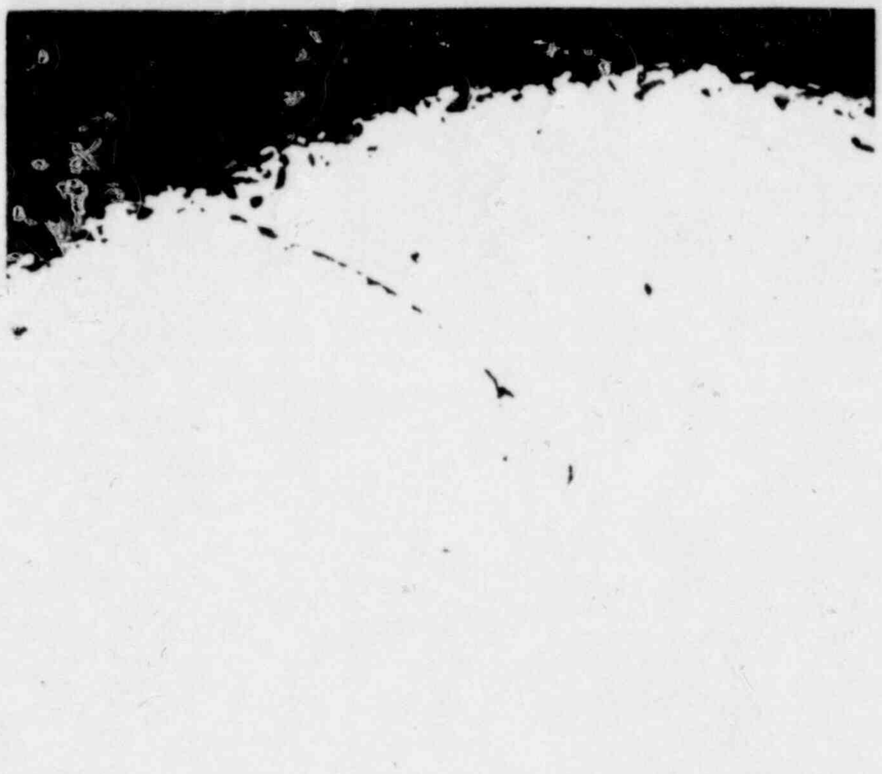
Typical X-section through A286 stator bolt - circulator 2103.

CIRCULATOR C-2103

X30

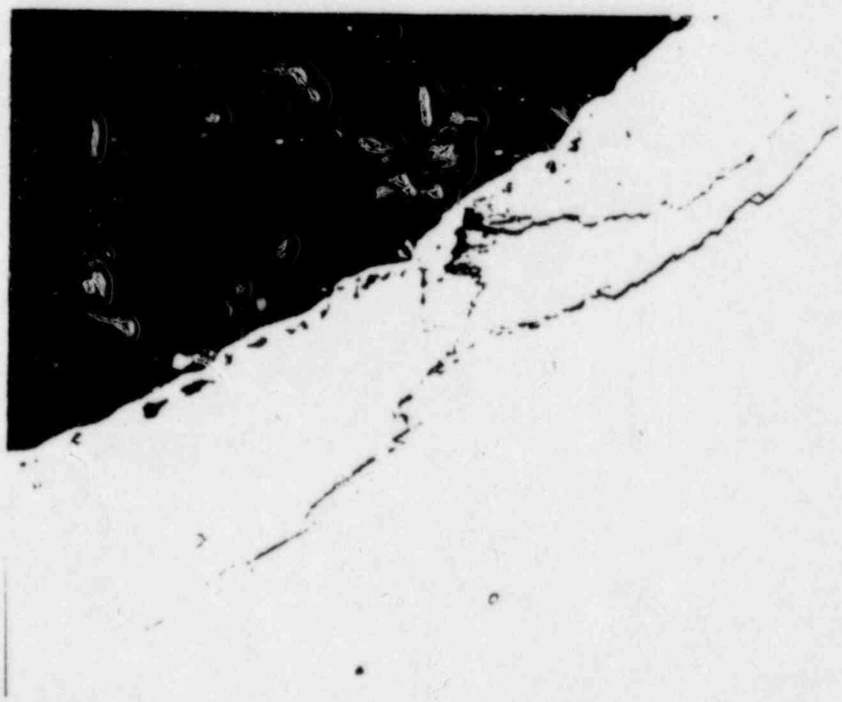
Typical section through A286 duct bolt - circulator 2103.

CIRCULATOR C-2103



X500

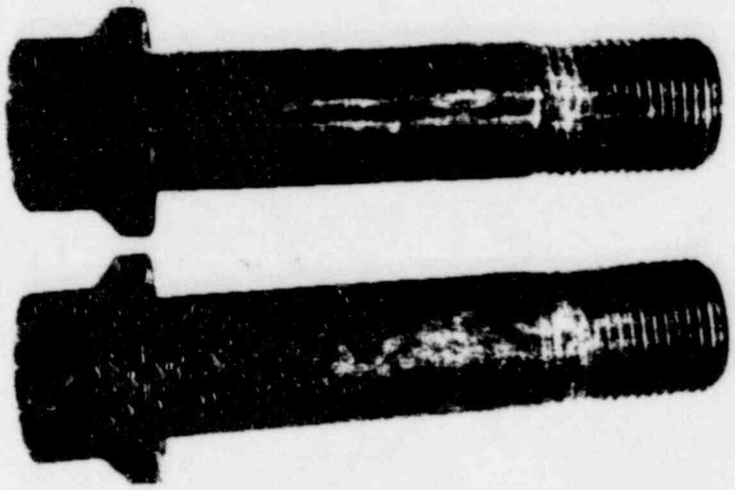
Crack in tip of thread of H11 primary closure bolt - circulator 2103.



X500

Stress corrosion crack in root of first thread adjacent to shank on H11 primary closure bolt - circulator 2103.

CIRCULATOR C-2104



Bolts 2104A and 2104B As-Received condition

CIRCULATOR C-2102

Fracture faces of bolt 2102A

CIRCULATOR C-2105

X100

Thread root of primary closure bolt H11 from circulator 2105.

X100

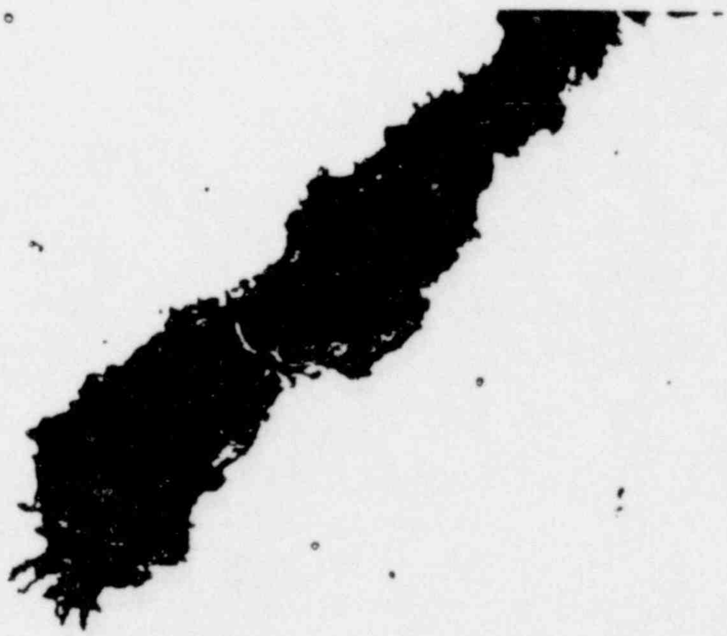
Thread root of Stator bolt A286 from circulator 2105.

CIRCULATOR C-2105

Isolated small corrosion pit in the root of primary closure bolt H11, C-2105

CIRCULATOR C-2105

X50



X500

SCC in the socket head of the primary closure bolt
H11, C-2105

FUTURE GAS CIRCULATOR DEVELOPMENT

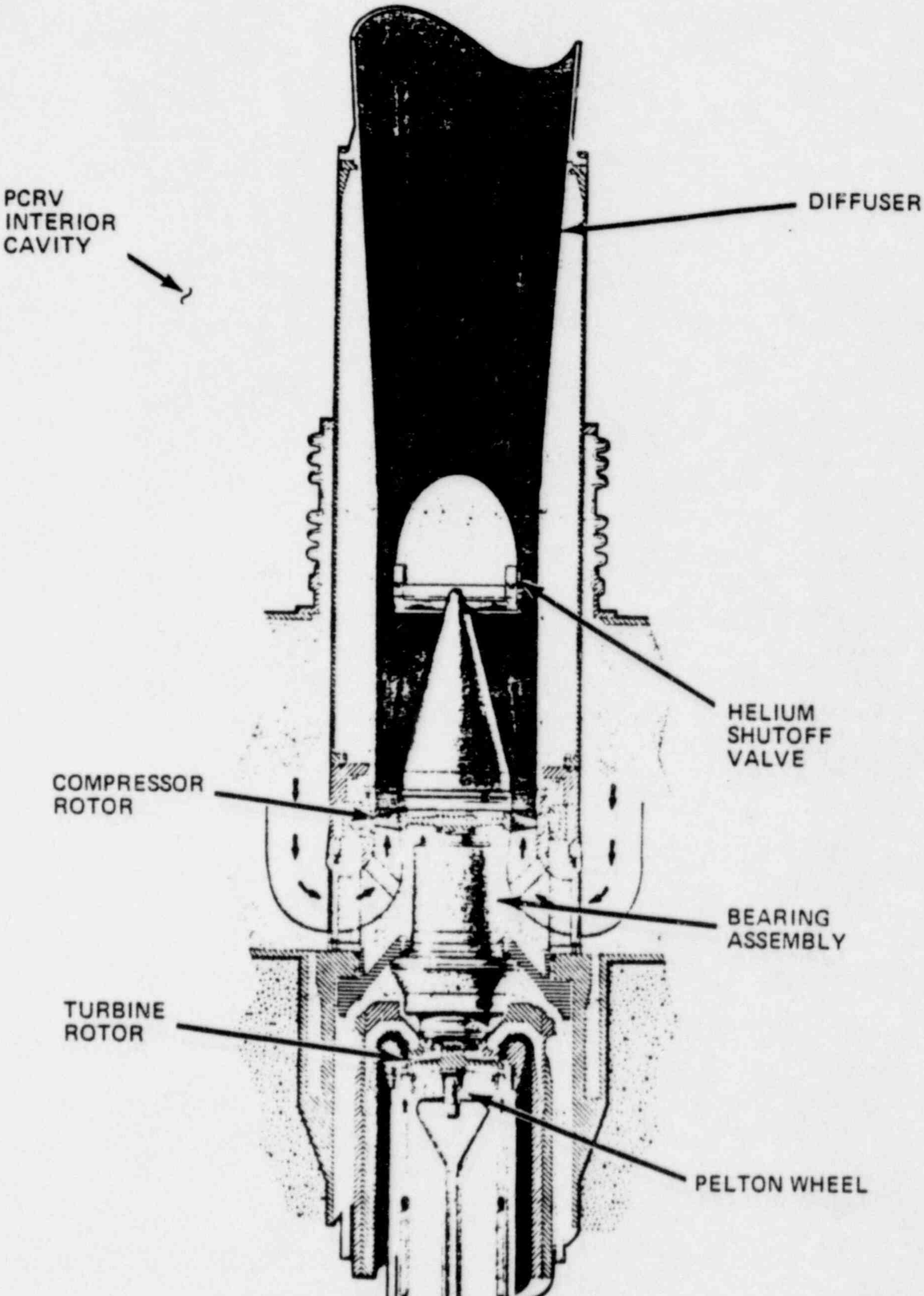


Figure 4.2-4 Helium Circulator Installation

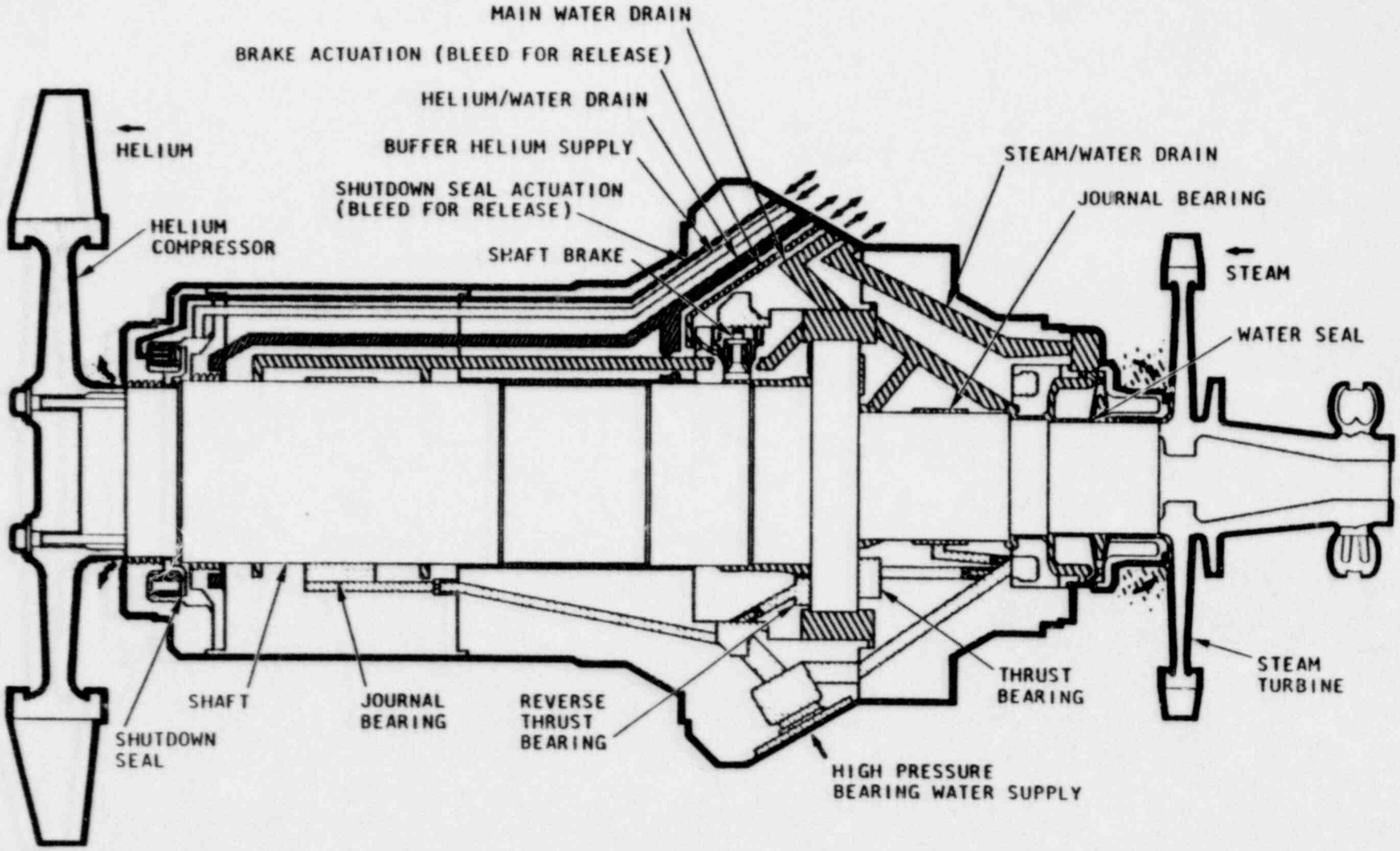


Figure 4.2-2 Helium Circulator Bearing and Seal Flow Arrangement

LC 92910

MAJOR HELIUM CIRCULATOR EVALUATED CONCEPTS

* NEW MAGNETIC BEARING, MOTOR DRIVEN, HERMETICALLY SEALED UNITS
* MODIFIED BASIC CIRCULATORS WITH:
  * ADDITION OF A SCAVENGING JET PUMP TO HELIUM WATER DRAIN
  * FIXED ORIFICE MAIN DRAIN
  * PLUGGING OF LOWER HELIUM WATER DRAIN PORTS
  * ADDITION OF A POSITIVE WATER INGRESS DETECTOR
  * ELIMINATION OF H.P. SEPARATORS, BACKUP BEARING WATER AND ACCUMULATOR SYSTEMS
  * REPLACE HELIUM RECIRCULATOR WITH AN EDUCTOR
  * COMPLETE SEPARATION OF BEARING WATER AND BUFFER HELIUM SYSTEMS SO EACH CIRCULATOR STANDS ALONE
  * THREE BEARING WATER PUMPS WITH UNINTERRUPTABLE POWER SUPPLIES FOR EACH CIRCULATOR

* NEW TOTALLY MAGNETIC BEARING, STEAM AND PELTON WHEEL DRIVEN UNITS
* MODIFIED EXISTING CIRCULATORS WITH HYDROSTATIC SEALS
  * PRELIMINARY ENGINEERING EVALUATION IN PROGRESS
* NEW CIRCULATORS WITH BASIC COMPONENTS EXCEPT:
  * REPLACE EXISTING THRUST BEARING WITH MAGNETIC BEARINGS

CONTROL ROD DRIVE SYSTEM

FAILURES, OVERHAUL, MODIFICATIONS, AND MAINTENANCE

JUNE 23, 1984 EVENT

- JUNE 22, 1984 - FAILURE OF SUDDEN PRESSURE RELAY RESULTS IN MOISTURE INGRESS TO PCRV

- REACTOR POWER REDUCED

- COMBINATION OF CORE COOLDOWN AND ICING OF THE ON-LINE PURIFICATION TRAIN RESULTS IN HIGH PRESSURE REACTOR SCRAM

- 6 OF 37 CRDOA'S FAIL TO AUTOMATICALLY INSERT UPON SCRAM AND ARE MANUALLY INSERTED

CRDOA DESIGN

- CONTROL ROD DRIVE
  - SHIM MOTOR
  - GEAR TRAIN

- CONTROL ROD SUSPENSION
  - HUB
  - CABLES
  - CLEVIS
  - CONTROL RODS (30 WT. % AND 40 WT. %)

- ORIFICE DRIVE
  - MOTOR
  - LEAD SCREW
  - ORIFICE VALVE

- BIOLOGICAL SHIELD

- RESERVE SHUTDOWN SYSTEM
  - MATERIAL (20 WT. % AND 40 WT. %)
  - HOPPER
  - PRESSURIZATION SYSTEM

- INSTRUMENTATION
  - POSITION POTENTIOMETERS
  - IN LIMIT SWITCHES
  - OUT LIMIT SWITCHES
  - RETRACT SWITCHES
  - SLACK CABLE SWITCHES

ROOT CAUSE IDENTIFICATION PHASE

JUNE, 1984 - NOVEMBER 1984

- THE SIX CRDOA'S THAT FAILED TO SCRAM ON JUNE 23, 1984, WERE EXAMINED AND REBUILT.

- AN ADDITIONAL FOUR CRDOA'S WERE ALSO REBUILT.

- ROOT CAUSE IDENTIFICATION STUDIES ADDRESSED:
    - MOISTURE EFFECTS
    - SHIM MOTOR CONDITION
    - GEAR TRAIN CONDITION
    - POTENTIAL LUBRICATION INCOMPATABILITIES
    - OTHER MECHANICAL OBSTRUCTION/RESTRICTION THEORIES
    - TEMPERATURE EFFECTS

- SHIM MOTOR BEARING WEAR AND DEBRIS (NORMAL WEAR PRODUCTS) BUILDUP WERE DETERMINED TO BE THE PRIMARY CONTRIBUTORS.

- HIGH PRIMARY SYSTEM MOISTURE LEVELS MAY HAVE AGGRAVATED THE SITUATION.

FURTHER FAILURES EXPERIENCED

- CRDOA INSTRUMENTATION ANOMOLIES

  CAUSE: HIGH MOISTURE LEVELS

- CRDOA CABLE FAILURES

  CAUSE: CHLORIDE STRESS CORROSION CRACKING

- RSD SYSTEM MATERIAL RELEASE FAILURE

  CAUSE: BORIC ACID CRYSTALLIZATION

<u>REFURBISHMENT PROGRAM DEFINITION PHASE</u>

<u>NOVEMBER, 1984 - FEBRUARY, 1985</u>

- DECISION MADE TO REFURBISH <u>ALL</u> CRDOA's

- MAJOR PROGRAM OBJECTIVES:
    - REFURBISH SHIM MOTORS, REPLACE BEARINGS
    - REFURBISH GEAR TRAINS
    - REPLACE INSTRUMENTATION
    - REPLACE SS CABLES WITH INCONEL 625 CABLES
    - REPLACE RSD MATERIAL
    - INSTALL TEMPERATURE MONITORING DEVICES
    - INSTALL PURGE SEALS
    - REFURBISH ORIFICE DRIVES
    - REPLACE MATERIALS SUSCEPTIBLE TO CHLORIDE STRESS CORROSION CRACKING

SPECIAL REFURBISHMENT EQUIPMENT

- HOT SERVICE FACILITY EQUIPMENT
  - CAROUSEL
  - SHIELD WALL WITH LEAD GLASS WINDOWS
  - MANIPULATOR
  - HYDRAULIC CABLE CUTTER
  - TV CAMERAS
  - CLEVIS CASK AND CART
  - SPECIAL HEPA FILTER VENTILATION
  - RSD SYSTEM MAINTENANCE STATION
- EQUIPMENT STORAGE WELL STANDS
- 10 TON GANTRY CRANE
- AIR DRIVEN VACUUM CLEANER
- TRANSFER SHIELD WITH HEPA UNIT
- 200 ASSEMBLY CARTS WITH HEPA UNIT
- ULTRASONIC CLEANERS FOR DECONTAMINATION

REFURBISHMENT PROGRAM

FEBRUARY, 1985 - JUNE, 1985

- THIRTY-SEVEN CRDOA'S REFURBISHED

- SPECIAL TESTING TO CONFIRM OPERABILITY
  - SHIM MOTOR WATTAGE CHARACTERISTICS
  - SCRAM TIME
  - BACK-EMF
  - DELIVERED TORQUE AT MOTOR (GEAR TRAIN)
  - TORQUE TO ROTATE MOTOR (MOTOR)
  - POSITION INDICATIONS

MID-PROGRAM CHANGES

- SHIM MOTOR BEARINGS
- GEAR LUBRICATION
- SHIM MOTOR STATOR COATING
- SLACK CABLE BUSHING RETAINER

RADIATION EXPOSURE DATA

- OVER 120 PEOPLE INVOLVED DAILY
- TOTAL PROGRAM EXPOSURE - 29 MAN REM
- MAXIMUM INDIVIDUAL EXPOSURE - 1.51 REM
- MAXIMUM SINGLE EXPOSURE - ~100 MREM

MODIFICATIONS

- CABLES
- RSD MATERIAL
- SHIM MOTOR BEARINGS
- STAINLESS STEEL PARTS SUSCEPTIBLE TO CHLORIDE STRESS CORROSION
- RESILIENT PARTS
- PURGE SEALS
- TEMPERATURE MONITORING DEVICES

CRDOA MAINTENANCE

PM PROGRAM

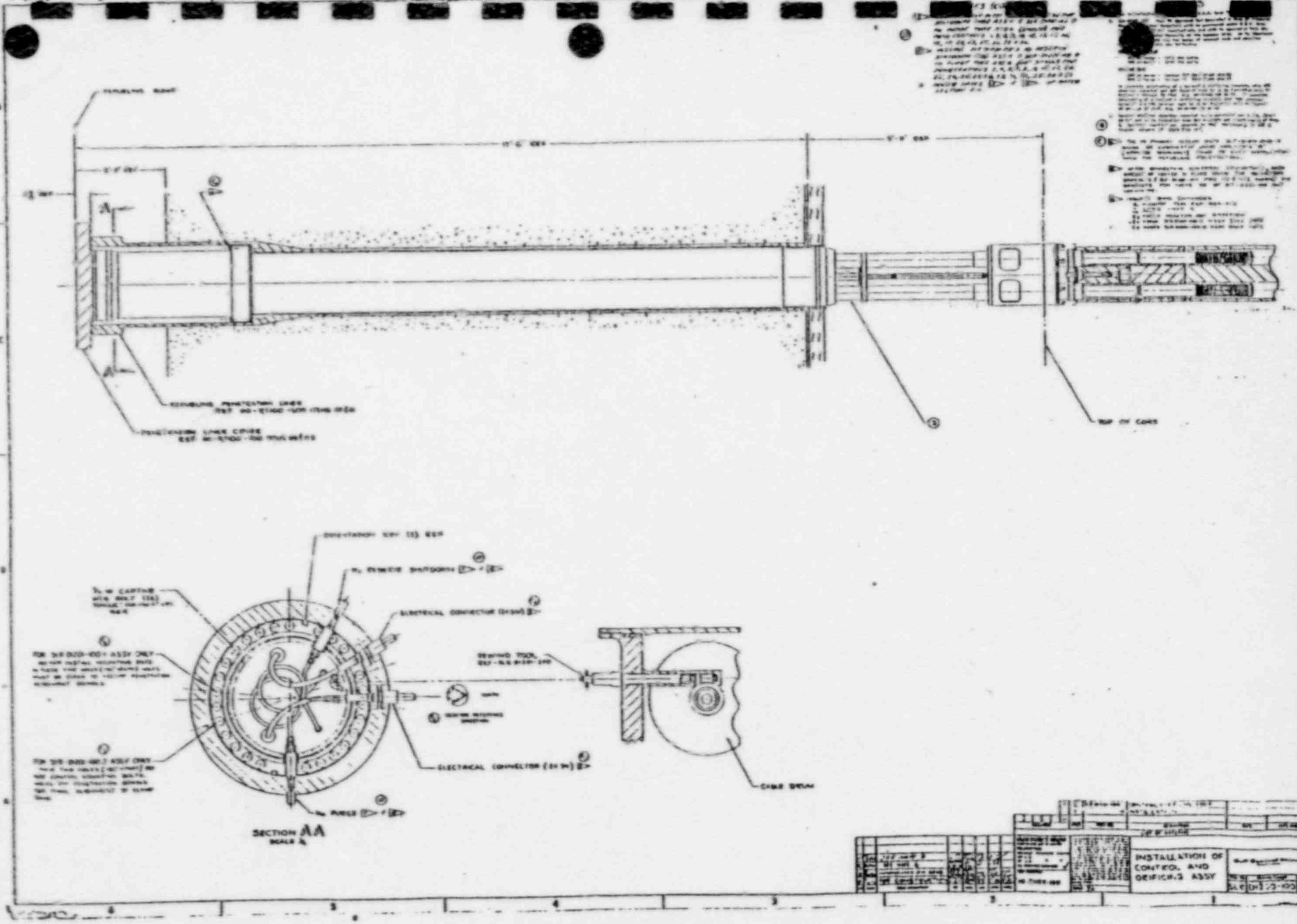
- REFUELING CYCLE FREQUENCY
- EXTENT AND FREQUENCY DEPENDENT ON PDM TESTING AND EXAMINATION
- SPECIAL AREAS ADDRESSED
  - SHIM MOTOR/BRAKE ASSEMBLY
  - DRIVE TRAIN
  - CABLE
  - RSD SYSTEM
  - INSTRUMENTATION
  - ORIFICE DRIVE
  - PENETRATION SEALS
  - CHECK VALVES
  - MCC CAPACITORS (VELOCITY LIMITERS)

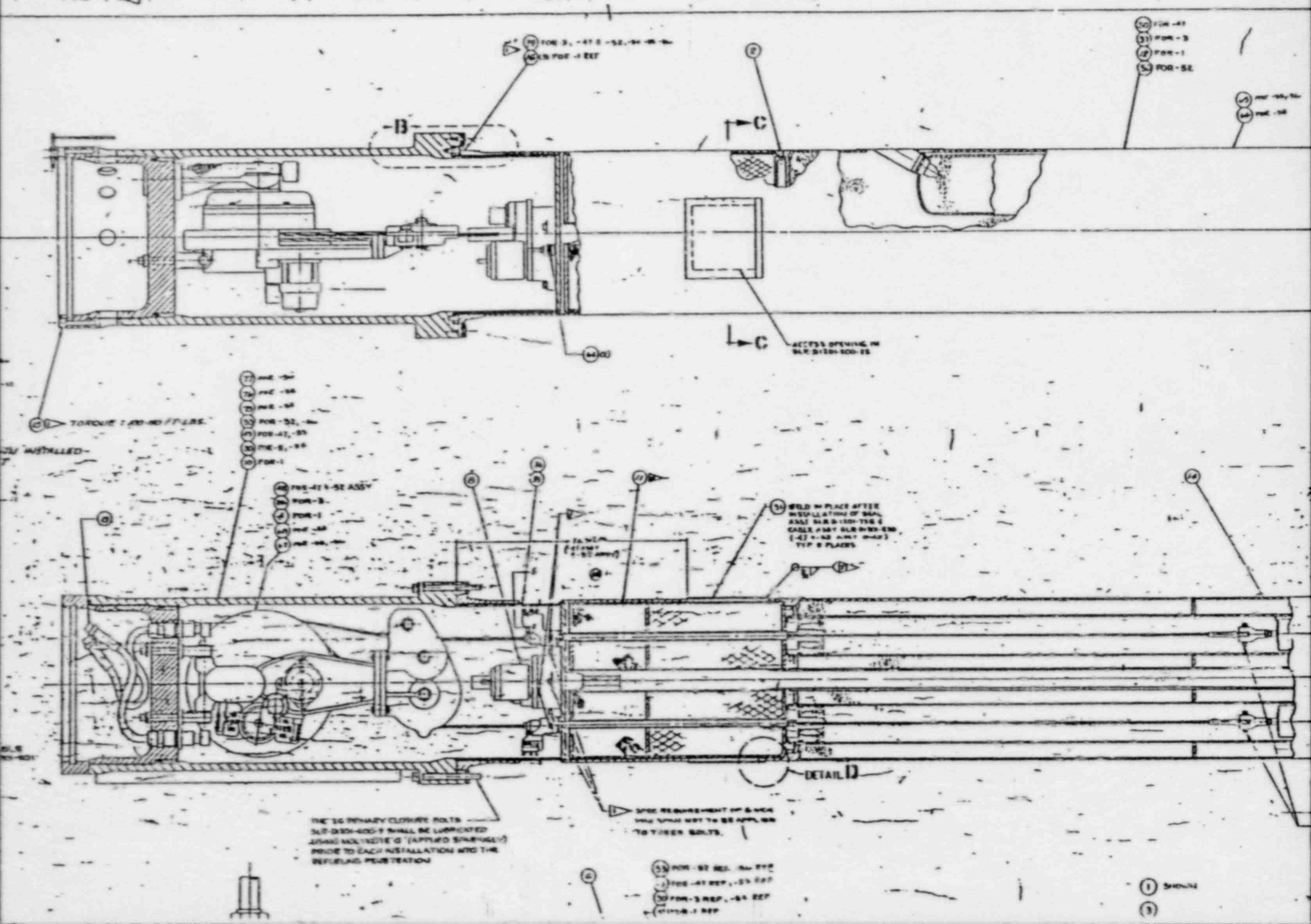
CRDOA MAINTENANCE

PDM PROGRAM

- IN CORE
  - SHIM MOTOR WATTAGE
  - SCRAM TIME
  - DROP RATE
  - BACK-EMF
  - ORIFICE DRIVE EXERCISING

- OUT OF CORE
  - DELIVERED TORQUE AT MOTOR
  - TORQUE TO ROTATE MOTOR
  - TORQUE TO ROTATE ORIFICE LEAD SCREW
  - TORQUE TO ROTATE ORIFICE MOTOR


TOP OF CORE
SECTION AA
CABLE DRUM
INSTALLATION OF
CONTROL AND
ORIFICING ASSY



-B-
C
C
FOR -52
DETAIL D
SHOWN

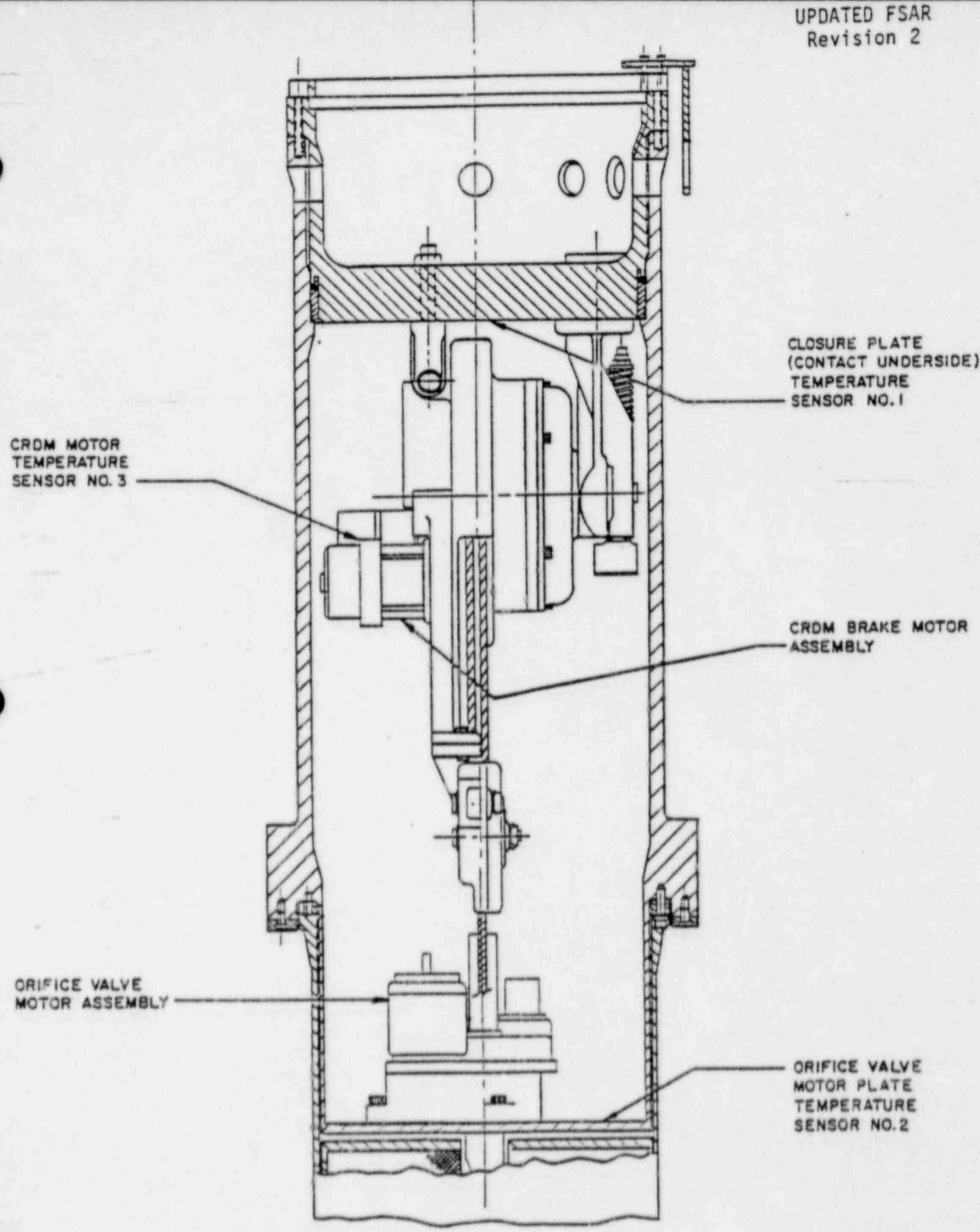


Figure 3.8-9 Control Rod Drive Mechanism Temperature Sensor Locations

1. CABLE DRUM
2. REDUCTION GEARING
3. DRIVE MOTOR
4. MOTOR BRAKE
5. POSITION TRANSMITTERS
6. ROD IN AND OUT LIMIT SWITCH CAMS
7. ROD IN AND OUT LIMIT SWITCHES
8. CONTROL ROD CABLES
9. GUIDE PULLEYS
10. SLACK CABLE INDICATOR DEVICES
11. SPRING
12. RTD TEMPERATURE SENSOR

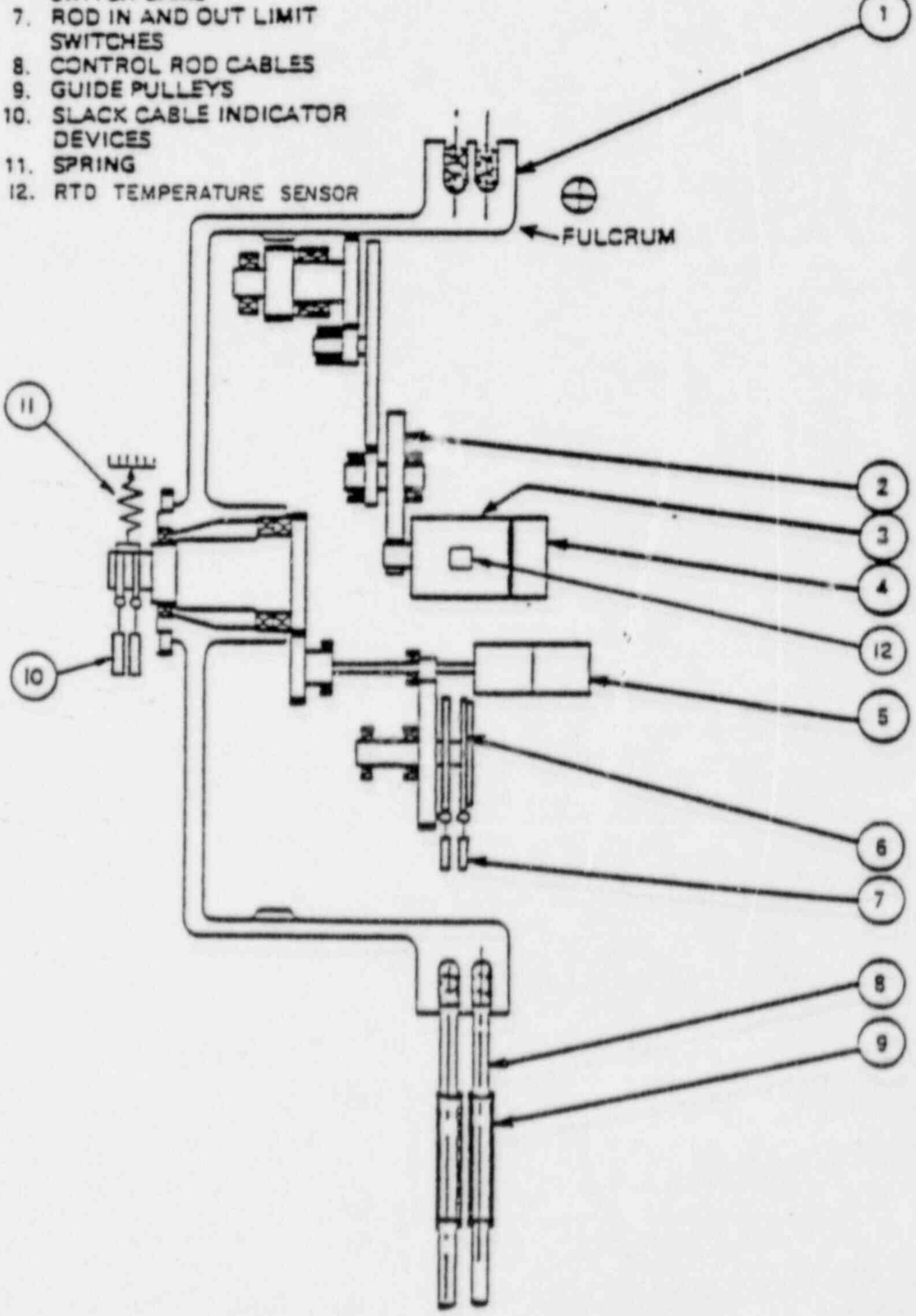


Figure 3.8-2 Control Rod Drive Mechanism Schematic

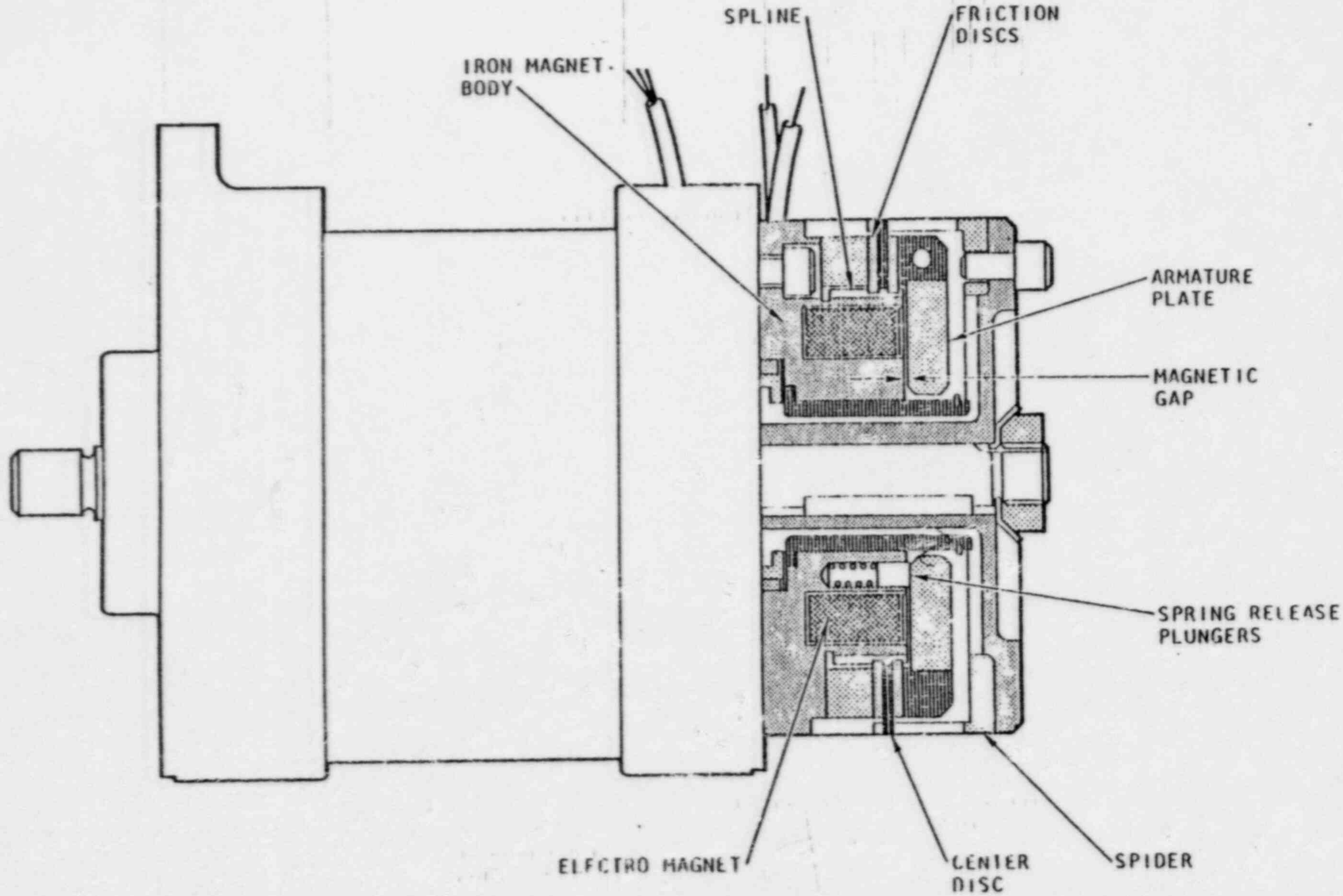
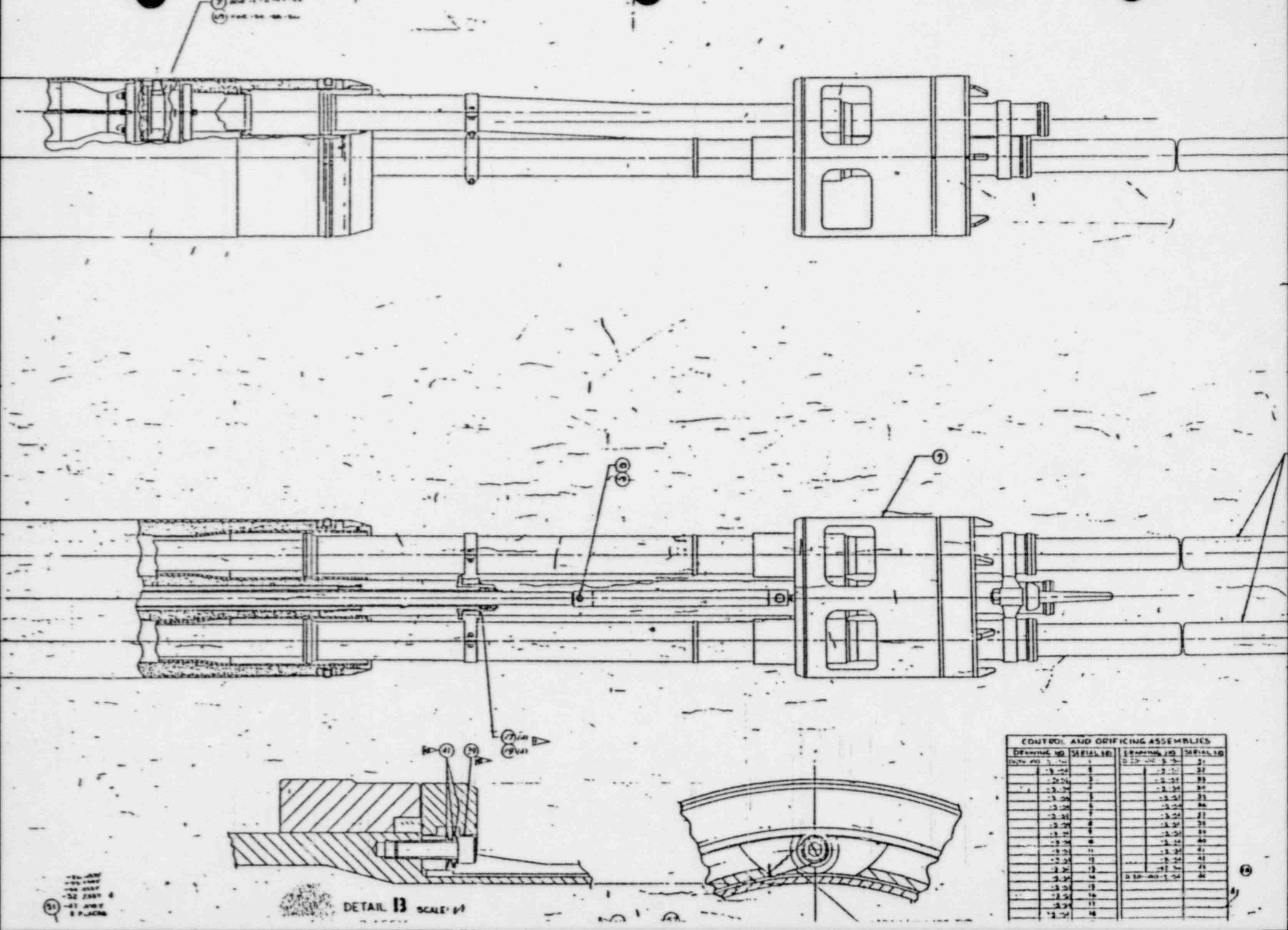


Figure 3.8-8 Control Rod Drive Brake


CONTROL AND ORIFICING ASSEMBLIES
DETAIL B

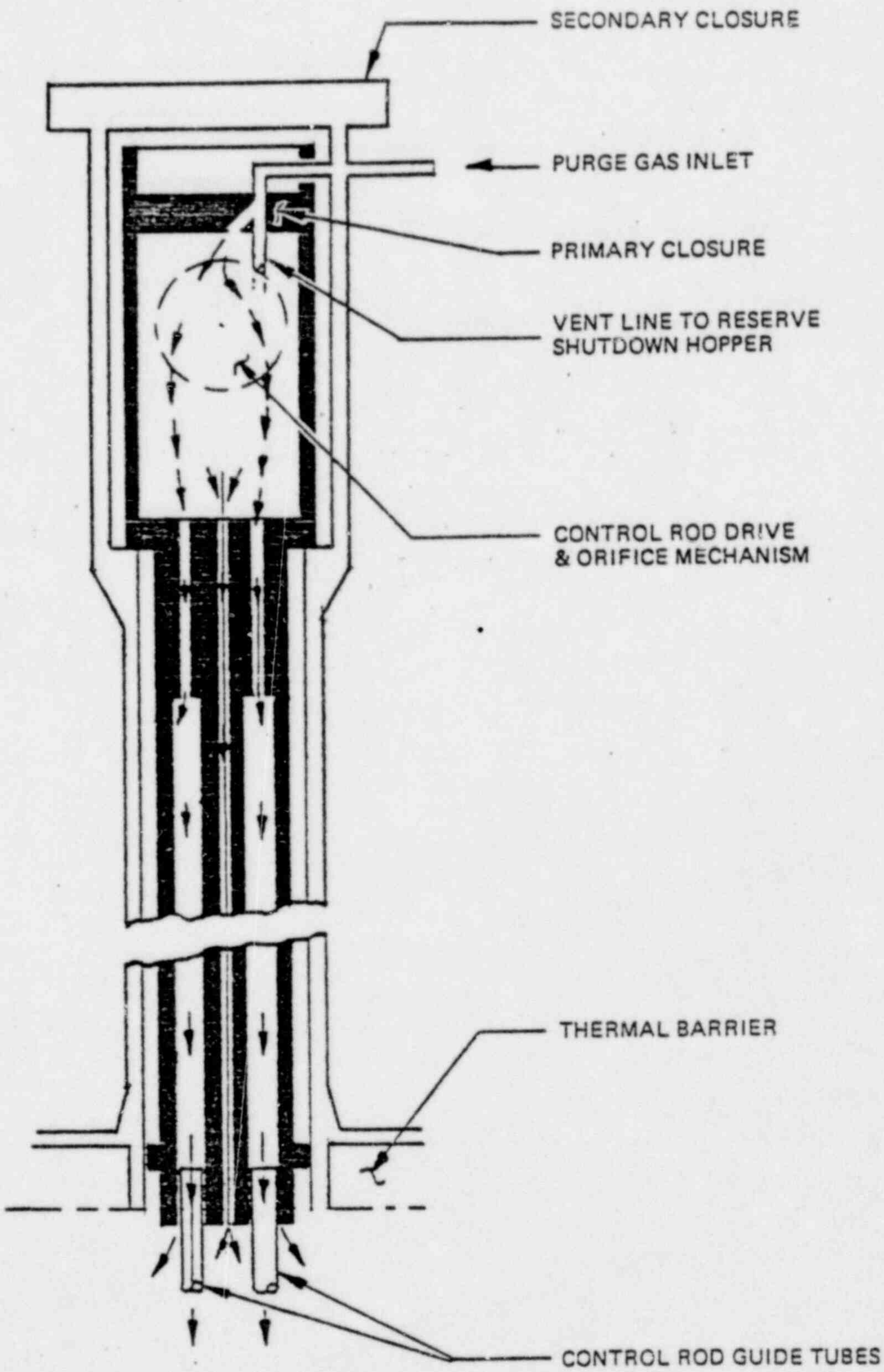


Figure 3.8-1 Control Rod and Orificing Assembly Purge Flow

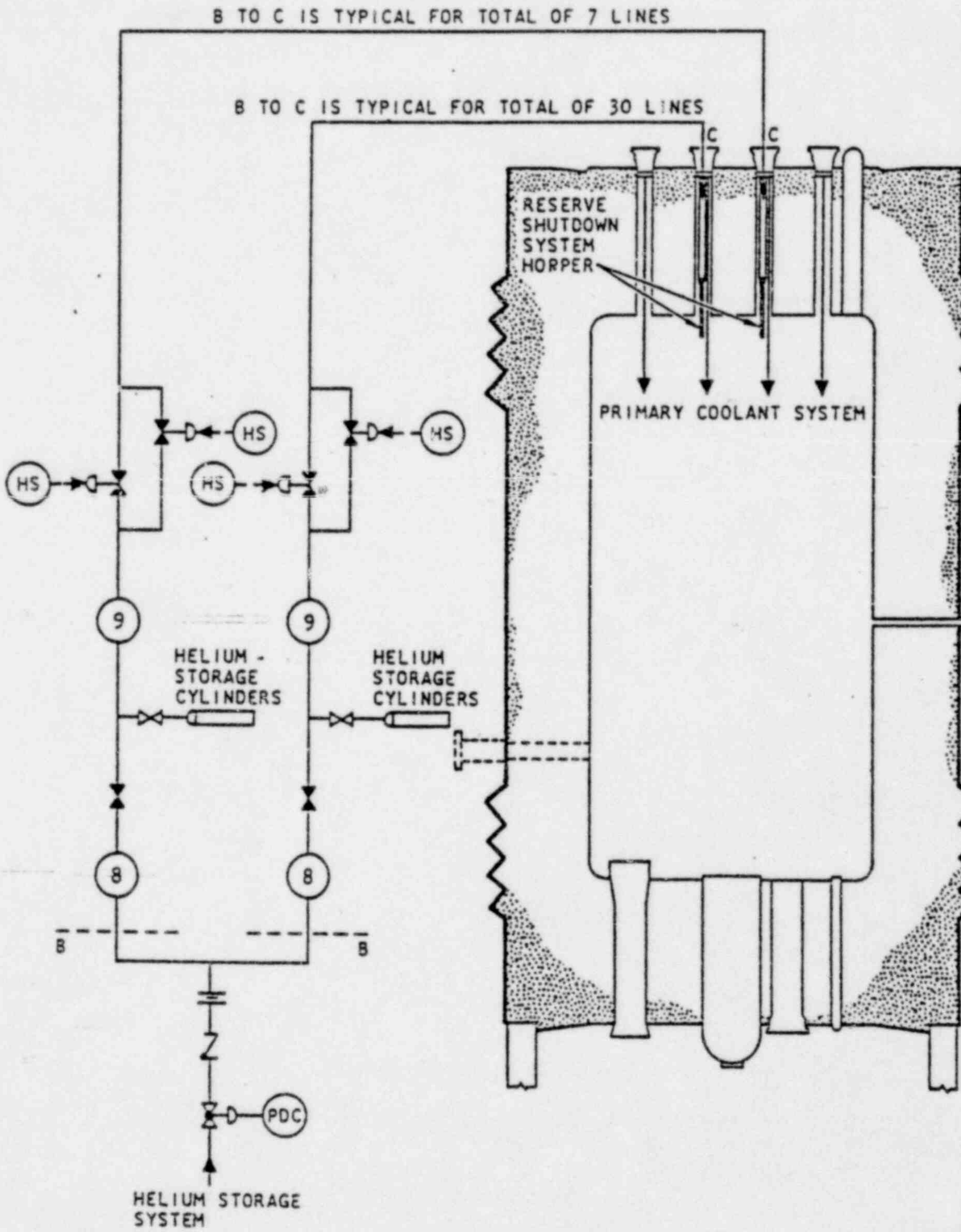
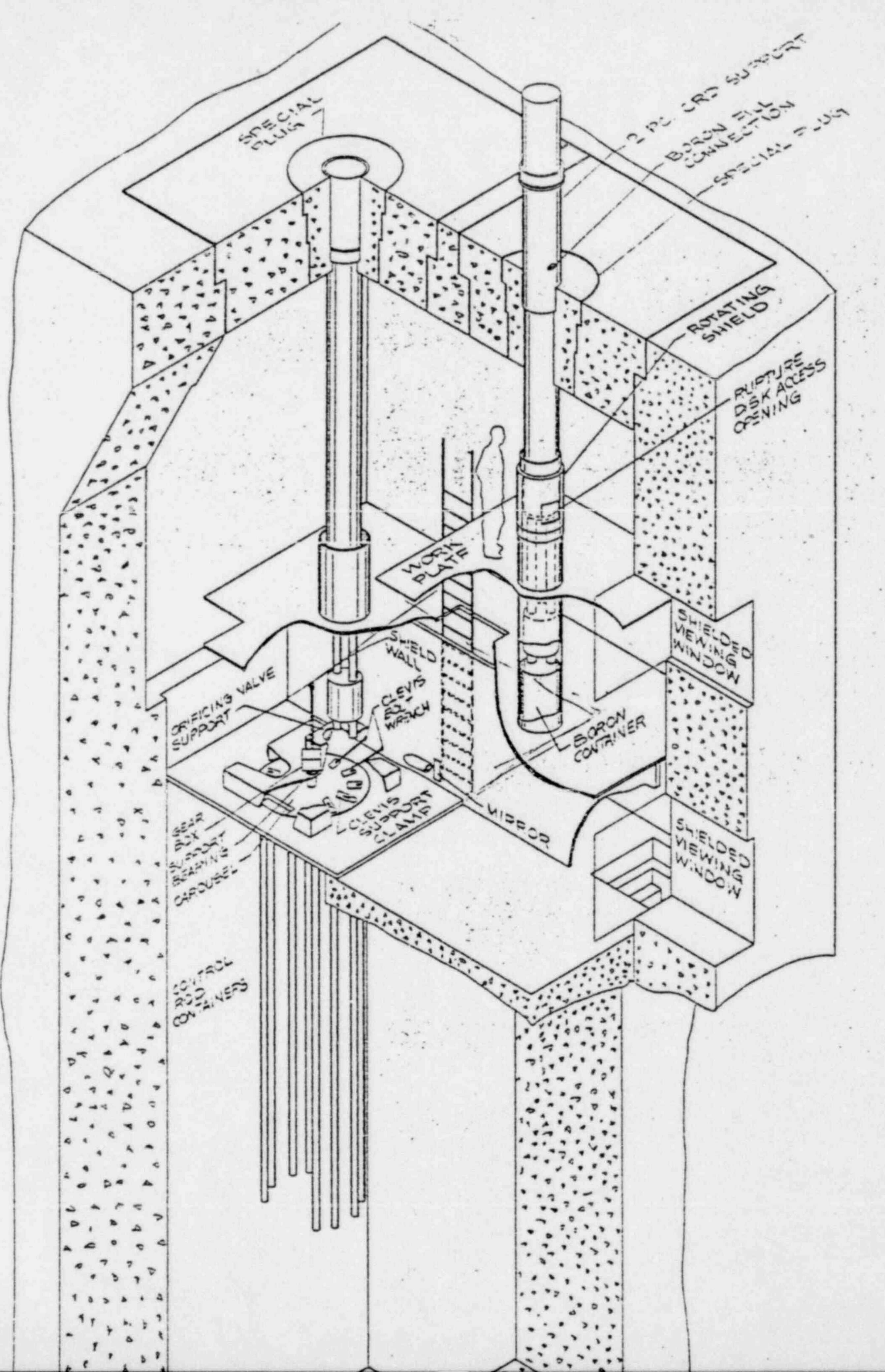


Figure 3.8-4 Reserve Shutdown System Flow Diagram


SPECIAL PLUG
2 PC CRD SUPPORT
BORON FILL CONNECTION
SPECIAL PLUG
ROTATING SHIELD
RUPTURE DISK ACCESS OPENING
WORK PLATF
SHIELDED VIEWING WINDOW
SHIELD WALL
ORIFICING VALVE SUPPORT
CLEVIS BOLT WRENCH
BORON CONTAINER
GEAR BOX
SUPPORT BEARING
CAROUSEL
CLEVIS SUPPORT CLAMP
MIRROR
SHIELDED VIEWING WINDOW
CONTROL ROD CONTAINERS

BACK EMF TECHNIQUE TO EVALUATE CONTROL ROD DRIVE PERFORMANCE

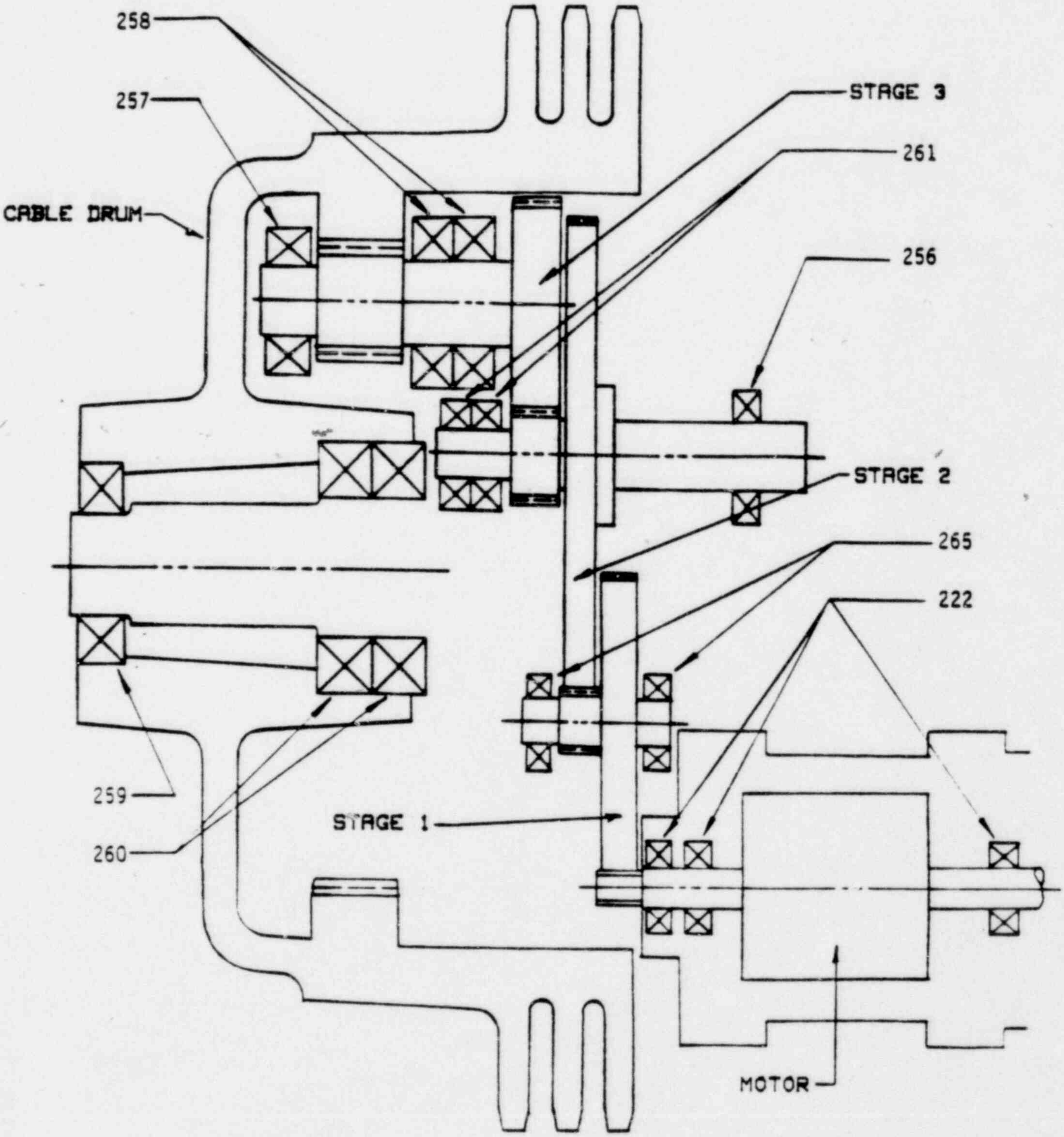
FORT ST VRAIN

CRDOA

BACK EMF VOLTAGE

- CRDOA OVERVIEW DESIGN
- BACK EMF DEVELOPMENT
- ANALYSIS
- PERFORMANCE CRITERIA
- PLANNED RESEARCH AND DEVELOPMENT

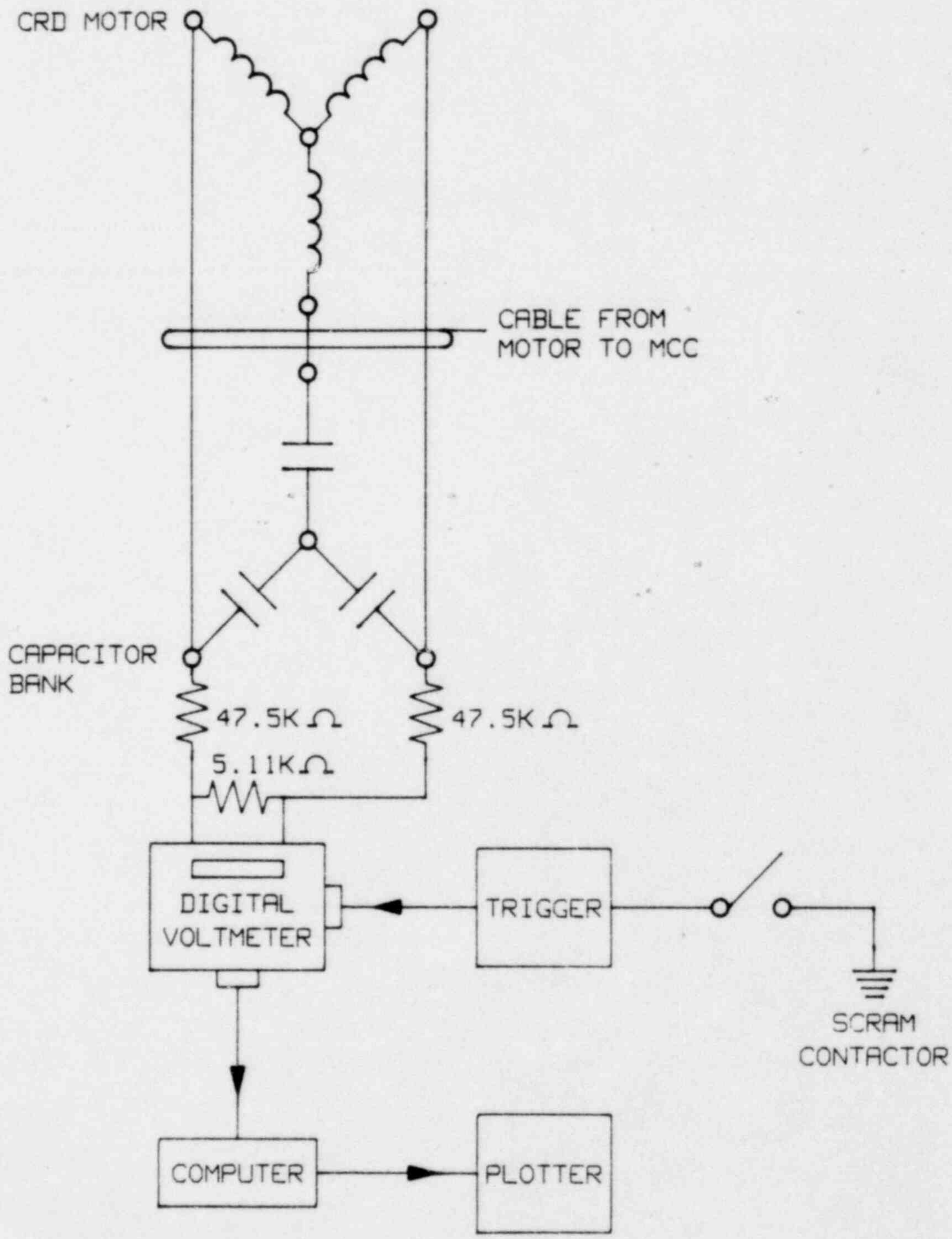
CRDOA GEAR TRAIN



ORIGINAL DESIGN INVESTIGATIONS

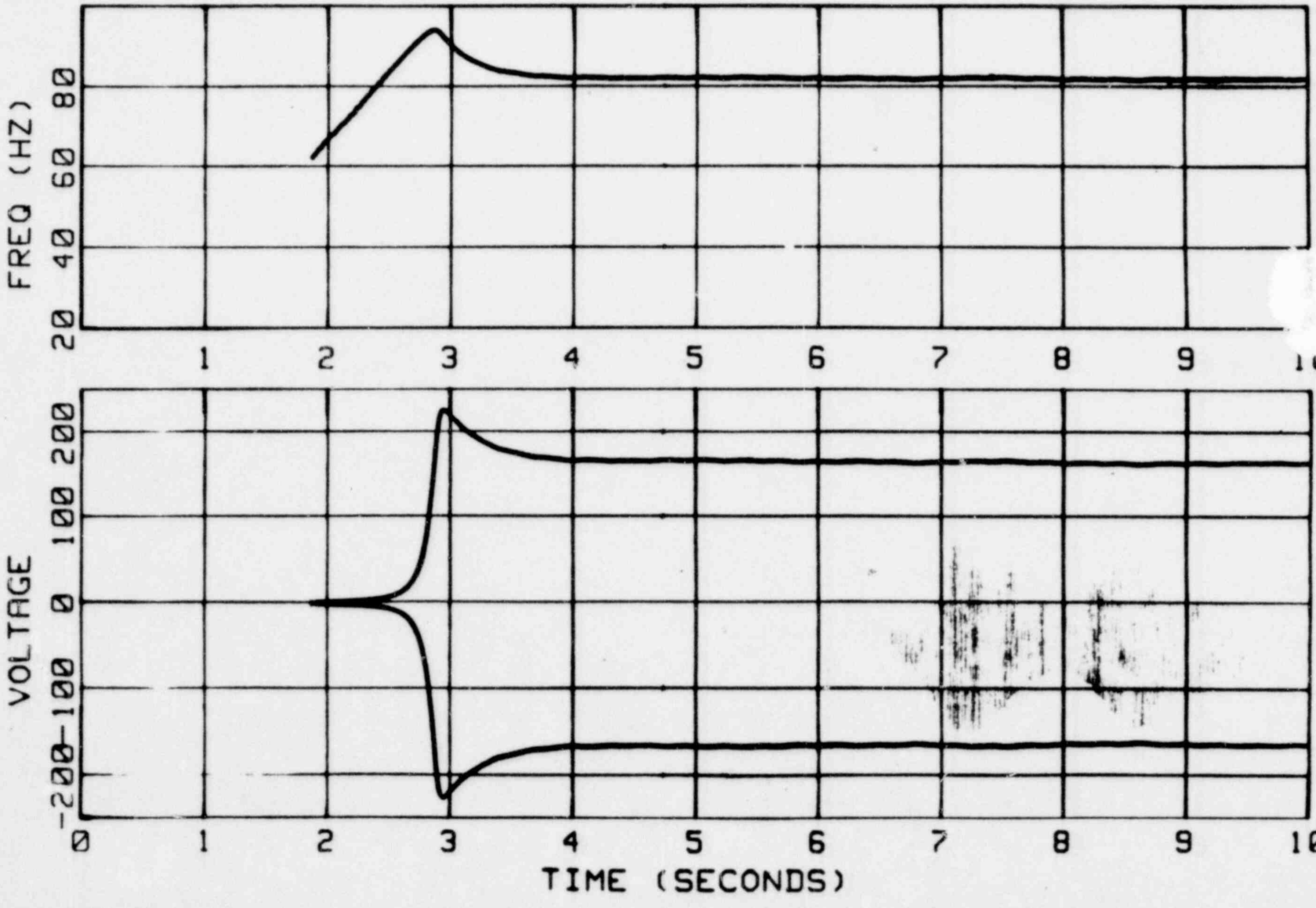
- HOLDING, INSERTION AND WITHDRAWAL TORQUE VALUES
- INSERTION AND WITHDRAWAL MOTOR WATTAGE
- BACK EMF VOLTAGE

CRD BACK EMF TEST CONFIGURATION

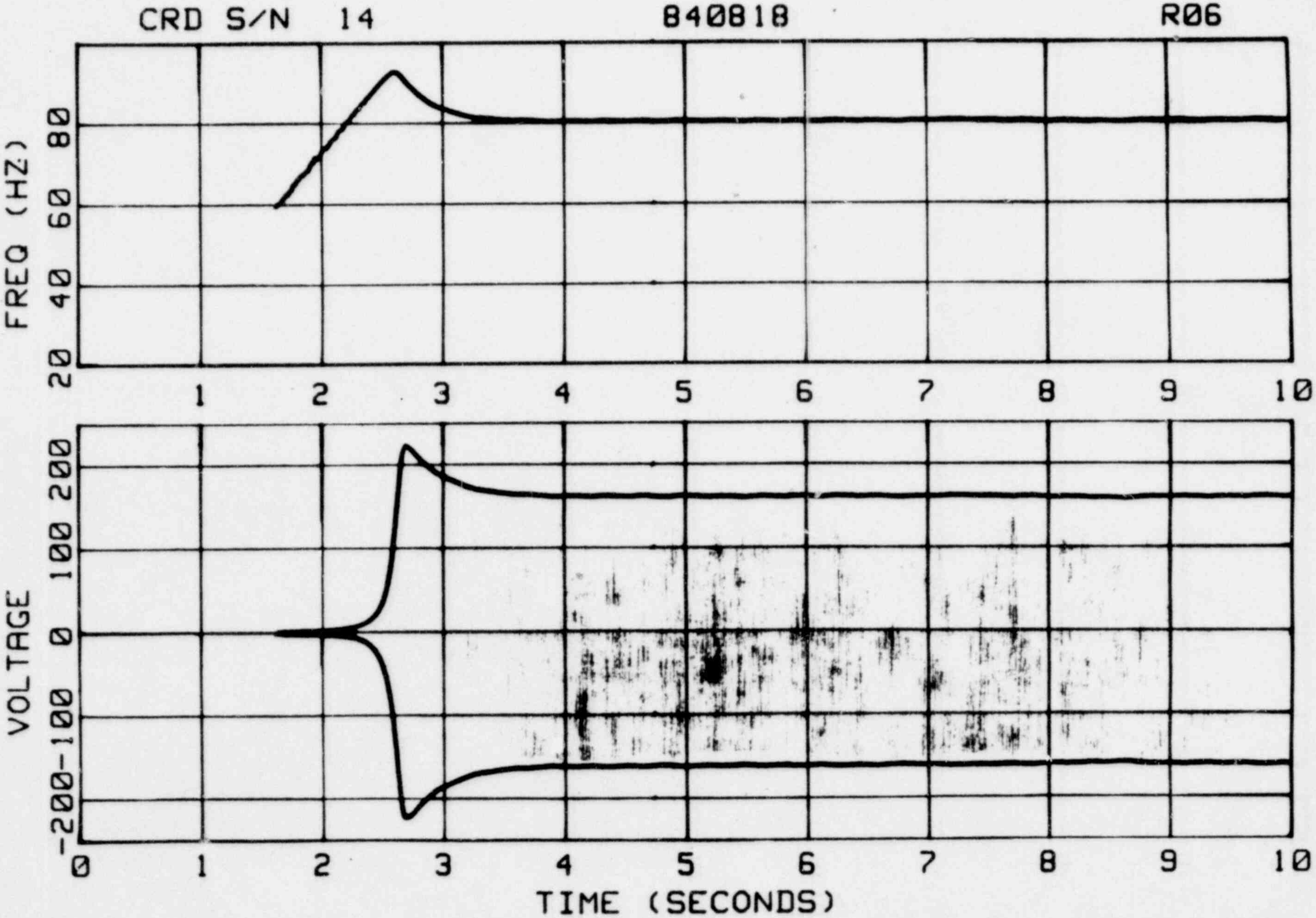


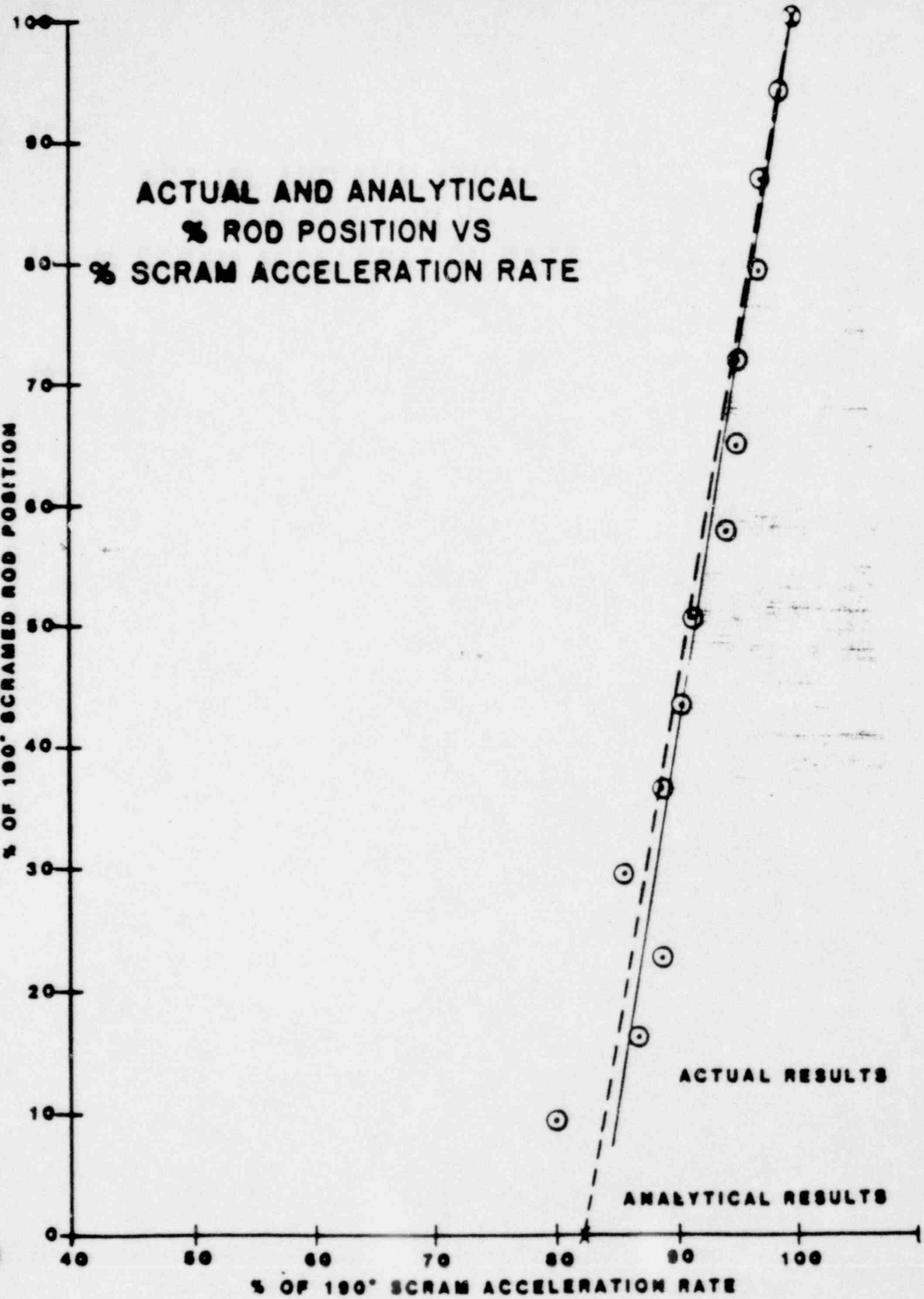
39 MICRO FARAD CAPACITORS

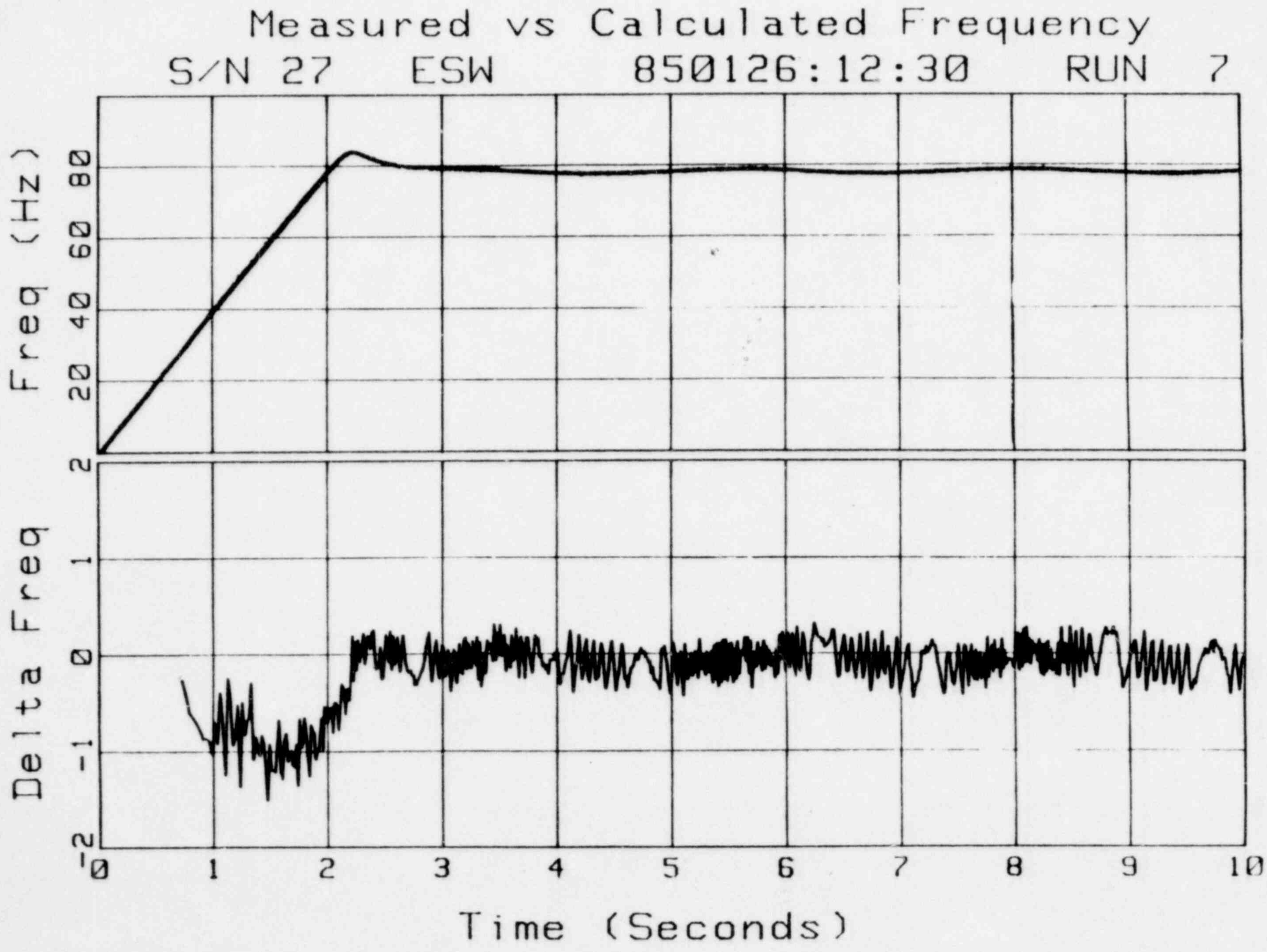
CRD S/N 14 840824 R06

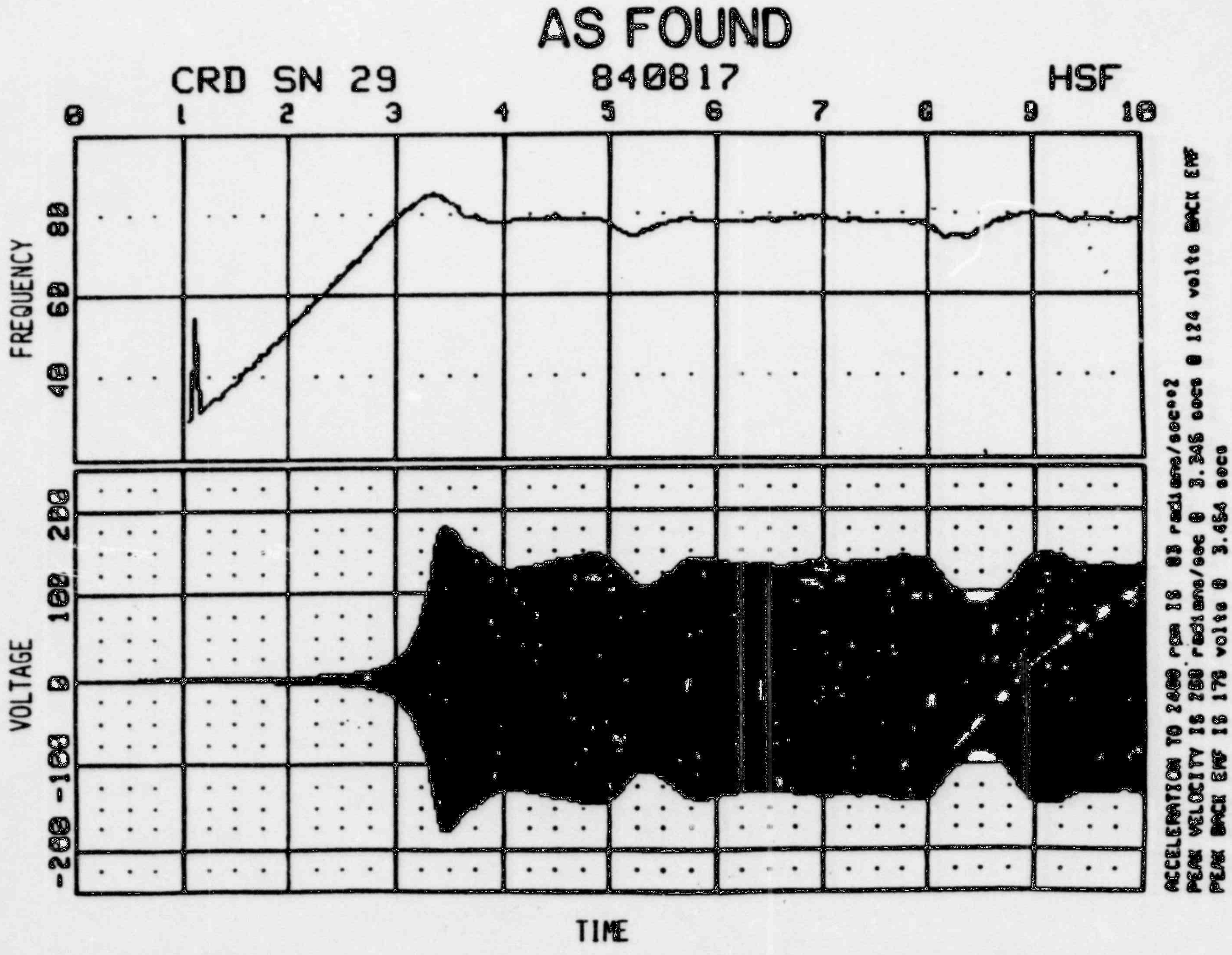


45 MICRO FARAD CAPACITORS



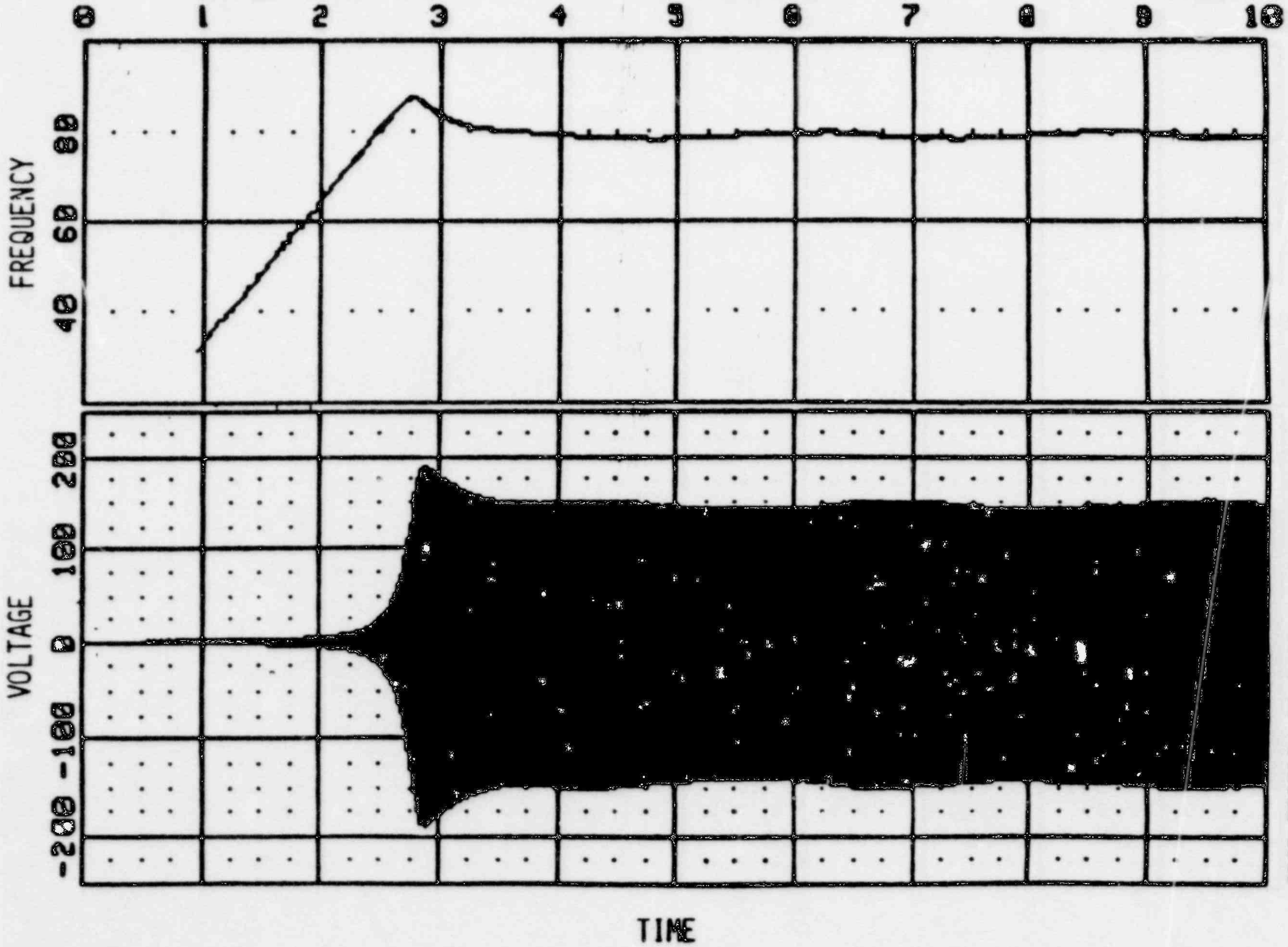

ACTUAL AND ANALYTICAL
% ROD POSITION VS
% SCRAM ACCELERATION RATE
% OF 100" SCRAMED ROD POSITION
% OF 100" SCRAM ACCELERATION RATE
ACTUAL RESULTS
ANALYTICAL RESULTS
0
10
20
30
40
50
60
70
80
90
100
40
50
60
70
80
90
100


Measured vs Calculated Frequency
S/N 27 ESW 850126:12:30 RUN 7
Freq (Hz)
20
40
60
80
Delta Freq
-2
-1
0
1
2
0
1
2
3
4
5
6
7
8
9
10
Time (Seconds)


AS FOUND
CRD SN 29
840817
HSF
0
1
2
3
4
5
6
7
8
9
10
FREQUENCY
80
60
40
VOLTAGE
200
100
0
-100
-200
TIME
ACCELERATION TO 2400 rpm IS 83 radians/sec**2
PEAK VELOCITY IS 260 radians/sec @ 3.345 secs @ 124 volts BACK EMF
PEAK BACK EMF IS 178 volts @ 3.454 secs

AFTER MOTOR

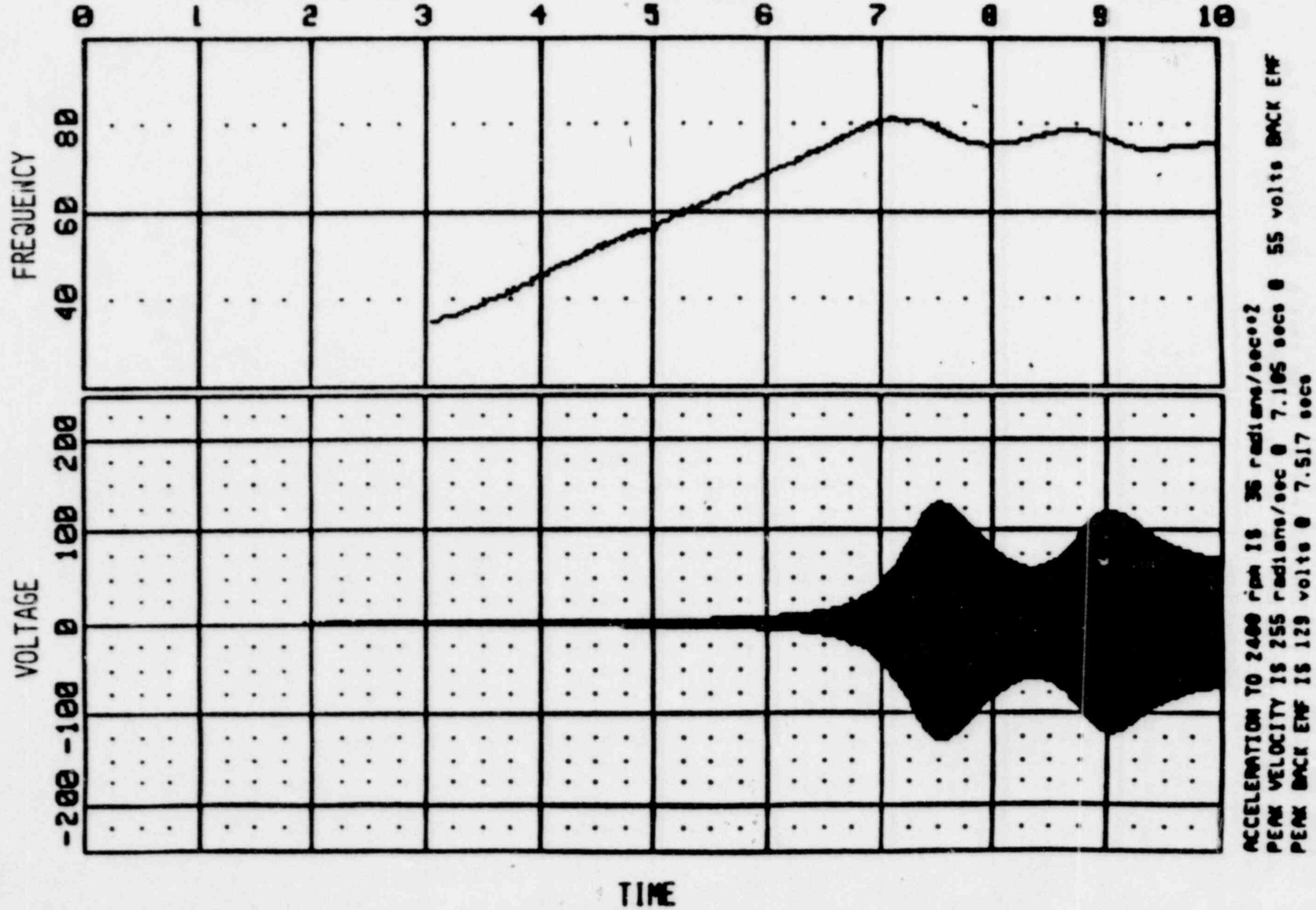
CRD SN 29 840818 HSF



ACCELERATION TO 2400 rpm IS 102 radians/sec**2
PEAK VELOCITY IS 275 radians/sec @ 2.762 secs @ 110 volts BACK EMF
PEAK BACK EMF IS 190 volts @ 2.800 secs

AFTER 200 ASSEMBLY

CRD SN 29 840821 HSF

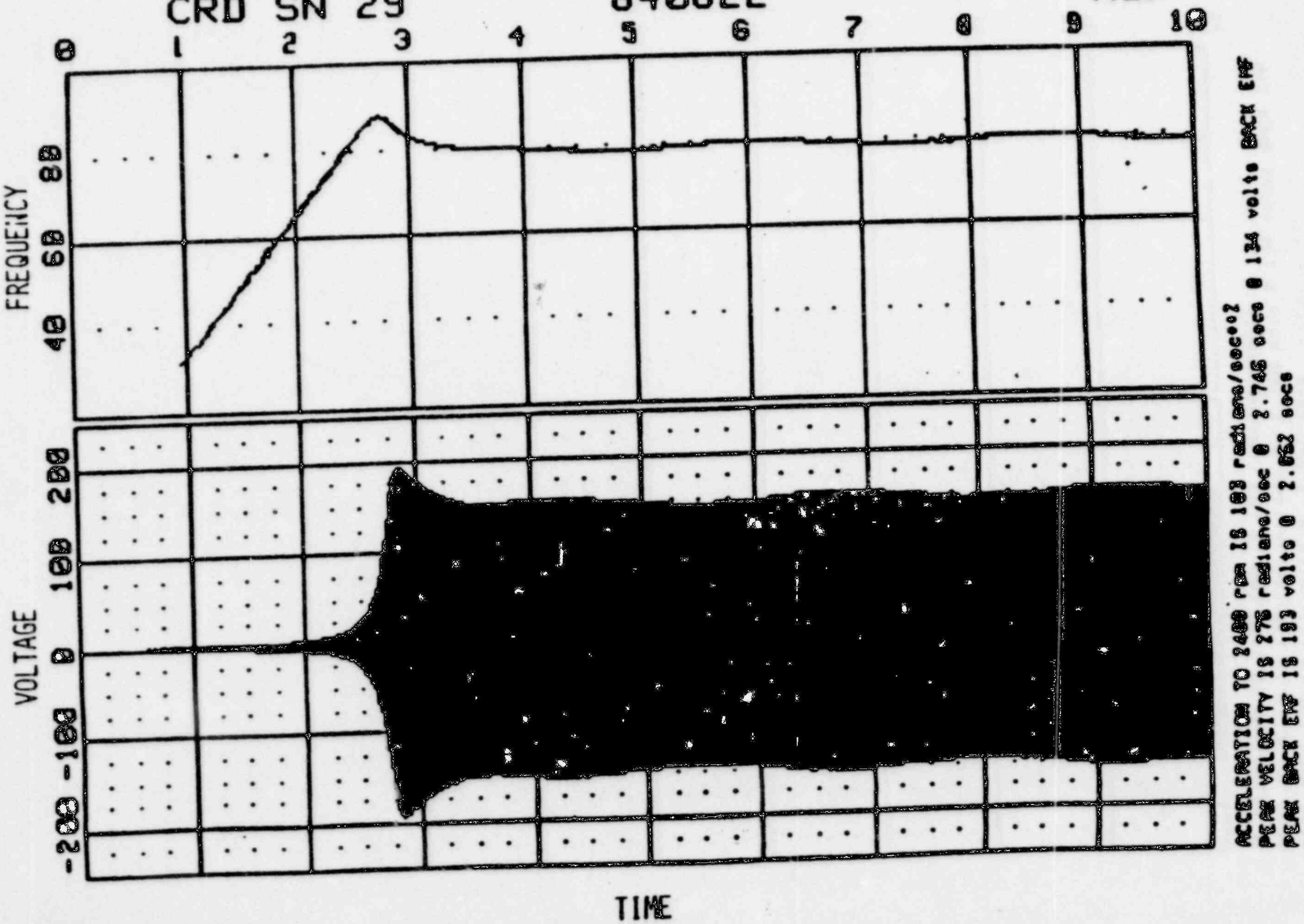


AS LEFT & AFTER 200 ASSEMBLY

CRD SN 29

840822

HSF



R O D   C O N D I T I O N (860324)

CRD S/N 07 LOC R27 860208 10:19 ROD POS 190.4" RUN 01

CORE: INLET TEMP 331 MOISTURE 778 SCRAM LENGTH: FULL

SR 4.1.1 D-X

CRD PASSED TEST
===============

STARTING MOMENT:	21.63 in-ozs
PEAK MOMENT:	3.22 in-ozs
AVERAGE ACCELERATION RATE:	126 rad/sec^2

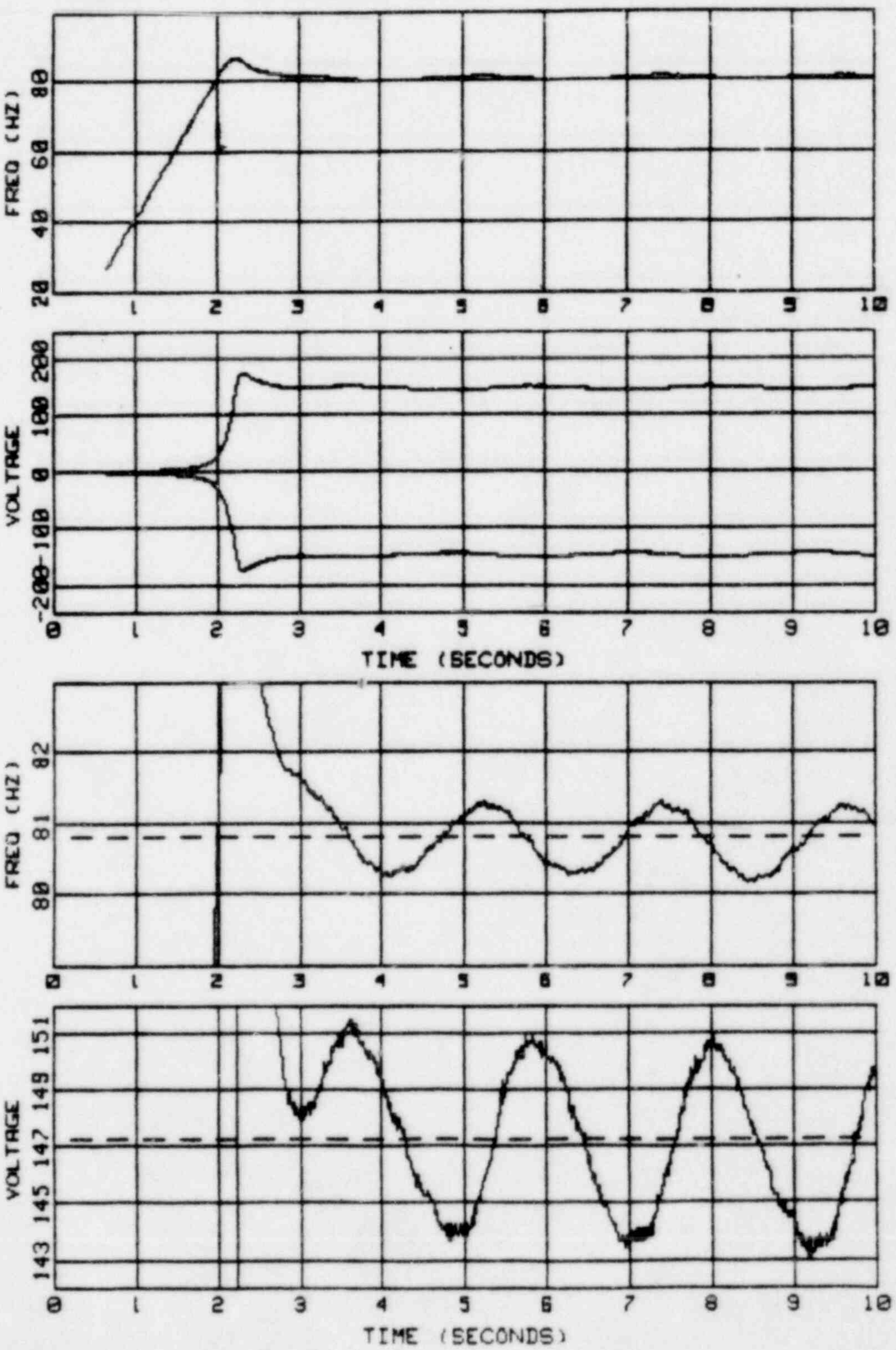
PEAK ANGULAR VELOCITY:	273.11 RAD/SEC	TIME TO PEAK VELOCITY:	2.215 SEC
PEAK BACK_EMF VOLTAGE:	174.0 VOLTS	TIME TO PEAK VOLTAGE:	2.307 SEC
STARTING MOMENT/ACCEL	21.63 / 125.7	ACTUAL SCRAM TIME:	10.0 SEC
MEAN STEADY STATE FREQNCY:	80.80 HZ	PROJECTED SCRAM TIME:	132.3 SEC

F R E Q U E N C Y / V O L T A G E vs T I M E (860324)

CRD S/N 07 LOC R27 860208 10:19 ROD POS 190.4" RUN 01

CORE: INLET TEMP 331 MOISTURE 778 SCRAM LENGTH: FULL

SR 4.1.1 D-X



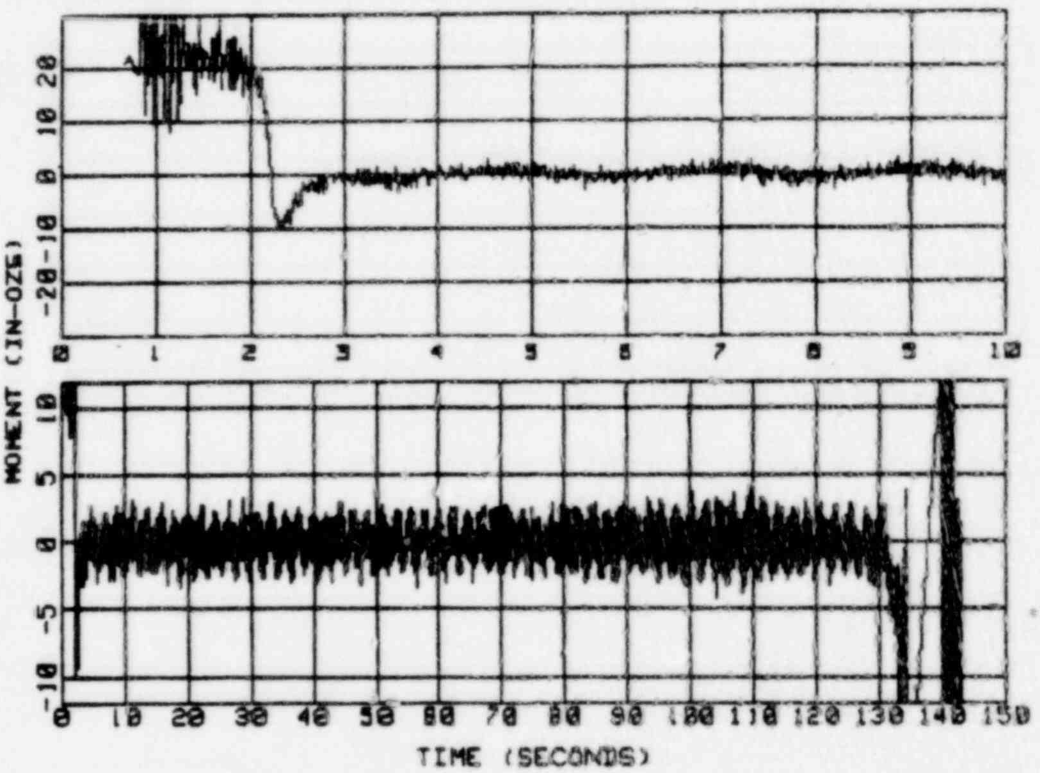
MOMENT vs TIME

(860324)

CRD S/N 07   LOC R27   860208   10:19   ROD POS 190.4"   RUN 01

CORE: INLET TEMP 331   MOISTURE 778   SCRAM LENGTH FULL

SR 4.1.1 D-X



PEAK ANGULAR VELOCITY: 273.11 RAD/SEC   TIME TO PEAK VELOCITY: 2.215 SEC

PEAK BACK_EMF VOLTAGE: 174.0 VOLTS   TIME TO PEAK VOLTAGE: 2.307 SEC

STARTING MOMENT/ACCEL 21.63 / 125.7   ACTUAL SCRAM TIME: 10.0 SEC

MEAN STEADY STATE FREQNCY: 80.80 HZ   PROJECTED SCRAM TIME: 132.3 SEC

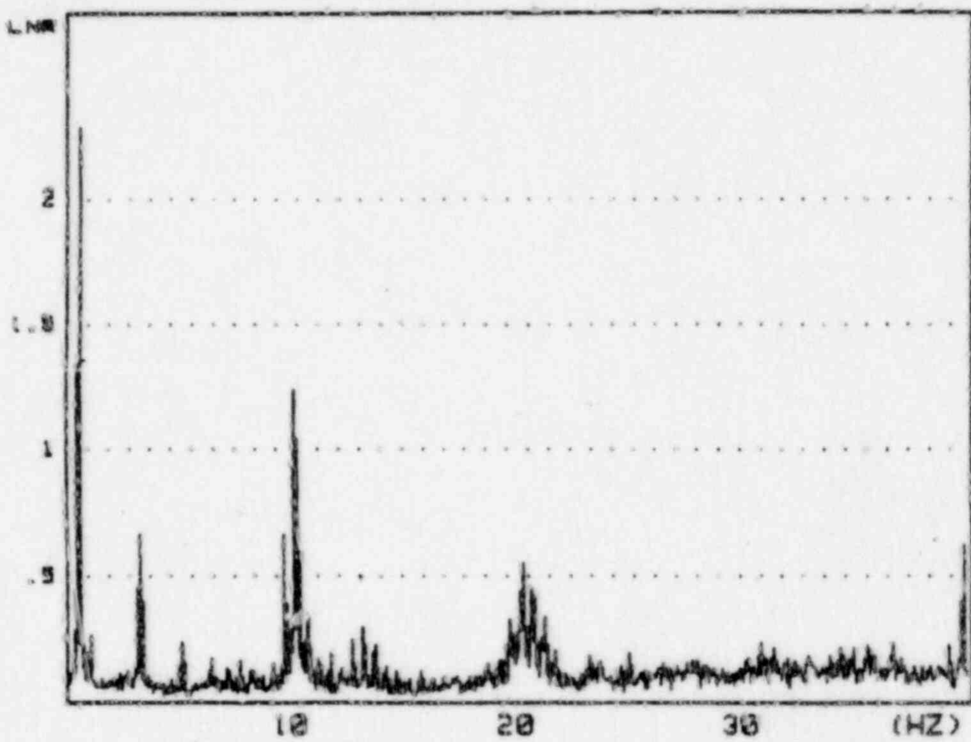
TIME	PEAK MOMENT	TIME	PEAK MOMENT
0 - 10	3.21933	70 - 80	2.84627
10 - 20	3.36241	80 - 90	2.99715
20 - 30	3.33527	90 - 100	3.24539
30 - 40	2.97328	100 - 110	4.09587
40 - 50	3.21774	110 - 120	3.23711
50 - 60	3.30338	120 - 130	3.26792
60 - 70	3.26644	130 - 140	26.08015
		140 - 150	29.47845

A V E R A G E   A C C E L E R A T I O N   F O U R I E R   (860324)

CRD S/N 07   LOC R27   860206   10:19   ROD POS 190.4"   RUN 01

CORE: INLET TEMP 331   MOISTURE 778   SCRAM LENGTH: FULL

SR 4.1.1 D-X



INITIAL ACCEL: 125.73   NUMBER OF SAMPLES: 1024   NUMBER OF FOURIERS: 20

PEAK VELOCITY: 273.11   ACCEL SAMPLE RATE: 80.0   PERCENTAGE OVERLAP: 90%

TIME TO PEAK: 2.215   SAMPLE START TIME: 2.88   FREQ RESOLUTION: .0781

STEADY ST TORQ: 3.22   SAMPLE END TIME: 9.22   MAXIMUM FREQNCY: 40.00

	SHAFT	MESH	FREQ	AMPL	FREQ	AMPL
M	40.3999		.54686	2.28196	20.39024	.38915
		565.5980	10.23418	1.23668	10.15606	.35653
1	4.1592		10.31230	.85212	10.78105	.34051
		108.1395	3.28119	.66663	21.32772	.33370
2	.5050		9.76544	.65942	20.23399	.32934
		10.1064	39.84300	.62371	19.76525	.32321
3	.2106		20.31212	.55373	10.39043	.32182
		3.1583	20.70273	.44994	.62499	.29754
D	.0351		20.78086	.40982	13.28100	.29570
			.46874	.39553	20.85898	.29563

R O D   C O N D I T I O N (860324)

CRD S/N 07 LOC R27 860313 12:02 ROD POS 190" RUN 01

CORE: INLET TEMP 331 MOISTURE 212 SCRAM LENGTH: PART

SR 4.1.1 D-X

CRD PASSED TEST
****

STARTING MOMENT: 21.46 in-ozs
PEAK MOMENT: 0.00 in-ozs
AVERAGE ACCELERATION RATE: 125 rad/sec^2

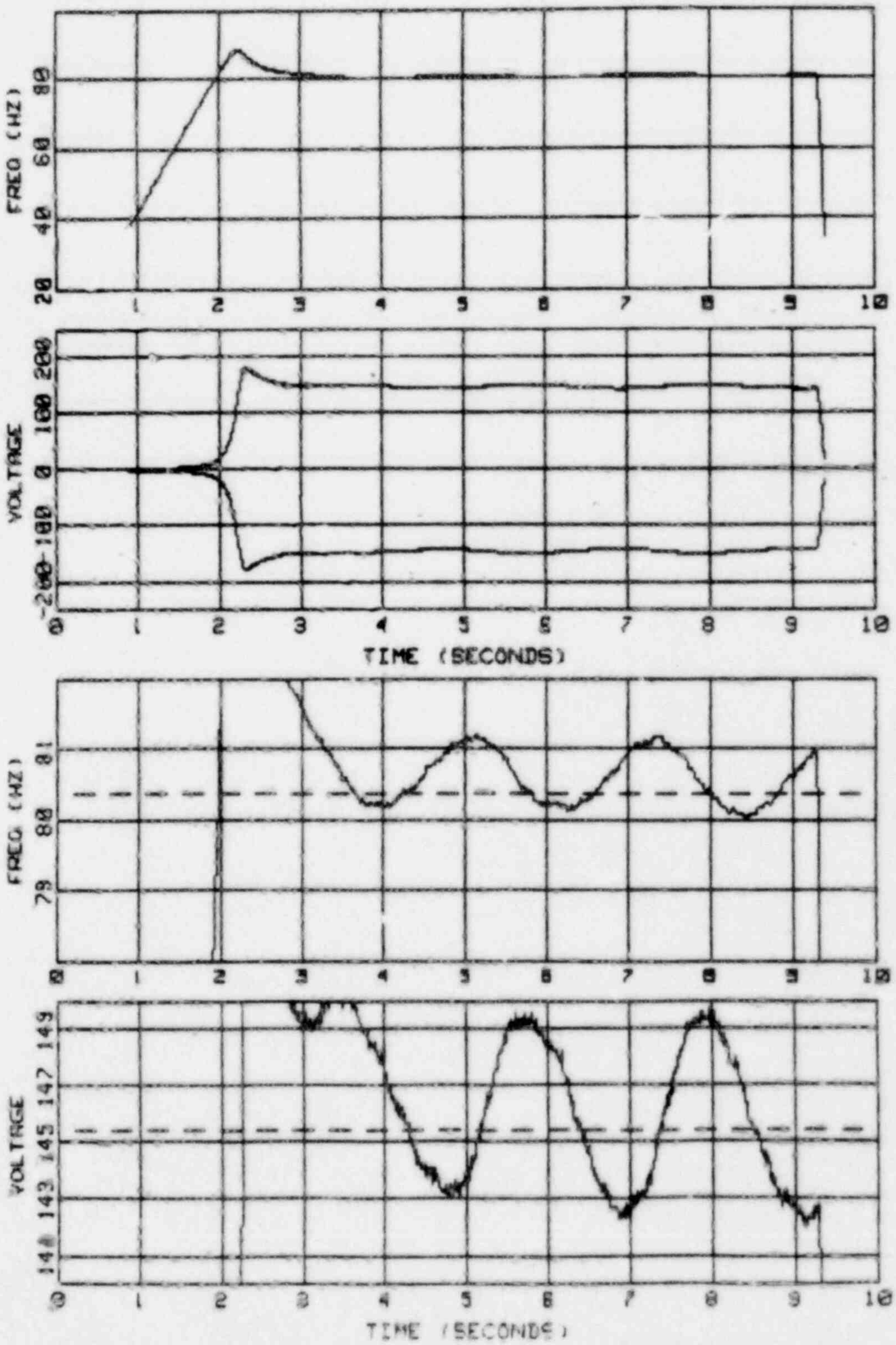
PEAK ANGULAR VELOCITY:	277.77 RAD/SEC	TIME TO PEAK VELOCITY:	2.252 SEC
PEAK BACK_EMF VOLTAGE:	179.0 VOLTS	TIME TO PEAK VOLTAGE:	2.320 SEC
STARTING MOMENT/ACCEL	21.48 / 124.9	ACTUAL SCRAM TIME:	9.4 SEC
MEAN STEADY STATE FREQNCY:	30.38 HZ	PROJECTED SCRAM TIME:	133.0 SEC

FREQUENCY / VOLTAGE vs TIME (860324)

CRD S/N 07 LOC R27 860313 12:02 ROD POS 190" RUN 01

CORE: INLET TEMP 331 MOISTURE 212 SCRAM LENGTH: PART

SR 4.1.1 D-X



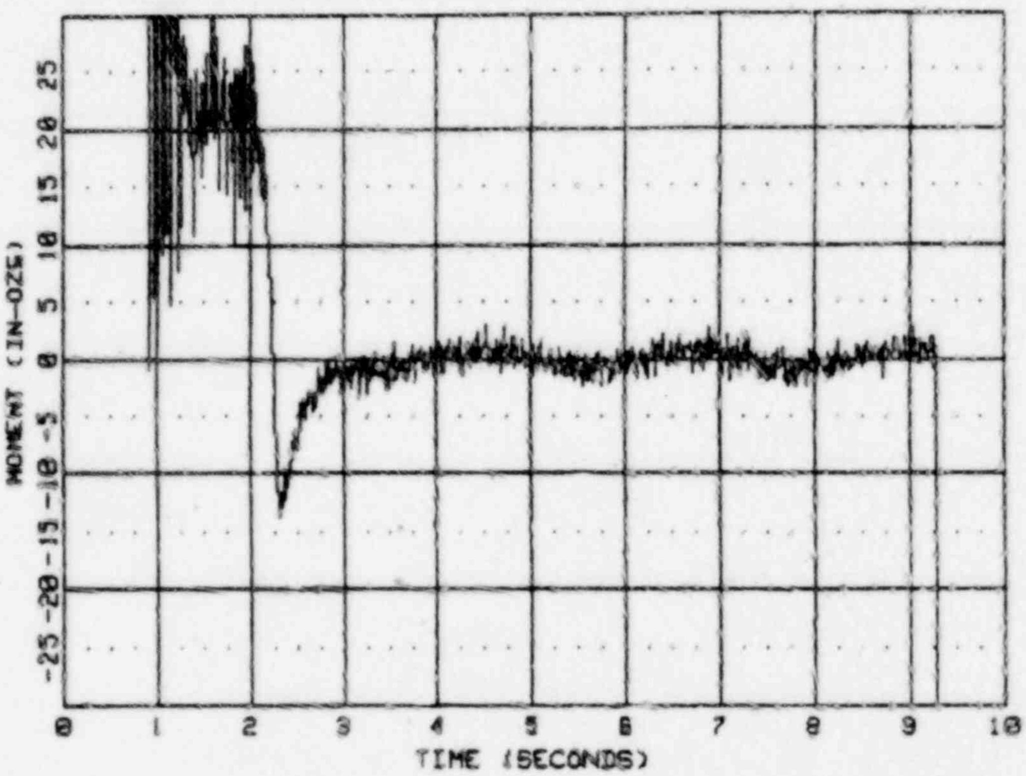
M O M E N T vs T I M E

(860324)

CRD S/N 07　LOC R27　860313　12:02　ROD POS 190"　RUN 01

CORE: INLET TEMP 331　MOISTURE 212　SCRAM LENGTH: PART

SR 4.1.1 O-X



PEAK ANGULAR VELOCITY: 277.77 RAD/SEC　TIME TO PEAK VELOCITY: 2.252 SEC

PEAK BACK_EMF VOLTAGE: 179.0 VOLTS　TIME TO PEAK VOLTAGE: 2.320 SEC

STARTING MOMENT/ACCEL 21.48 / 124.9　ACTUAL SCRAM TIME: 9.4 SEC

MEAN STEADY STATE FREQNCY: 80.38 HZ　PROJECTED SCRAM TIME: 133.0 SEC

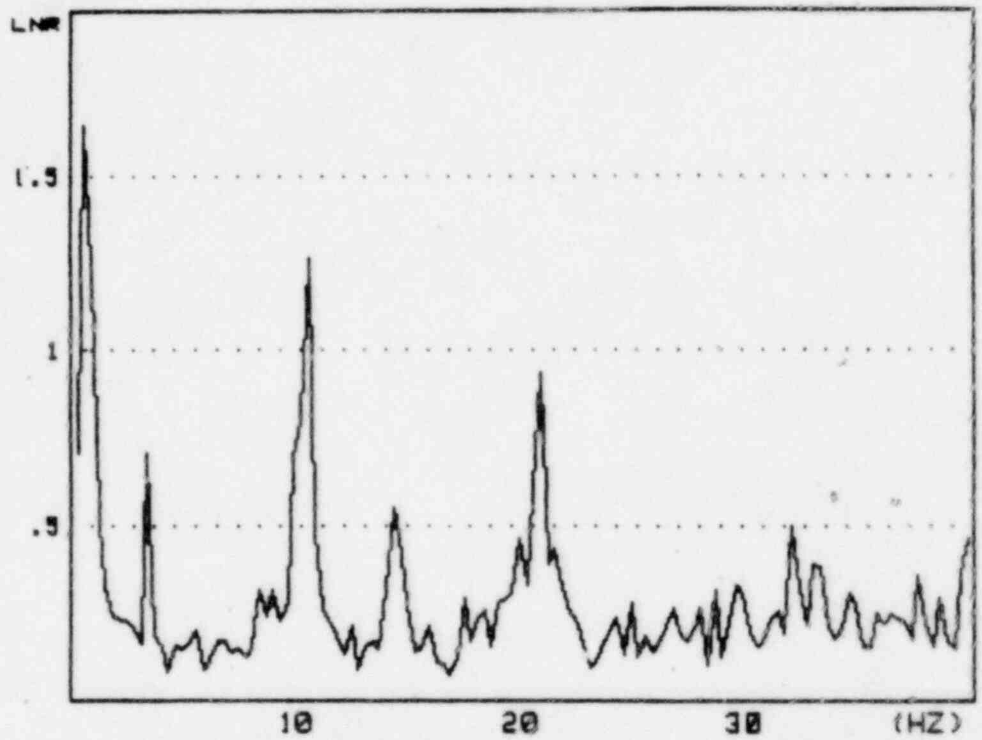
TIME	ACCEL	MOMENT	TIME	ACCEL	MOMENT
9.391	*******	******	4.524	16.619	3.021
9.369	*******	******	3.269	16.448	-2.907
9.352	*******	******	6.891	-16.155	2.858
9.336	*******	******	4.722	16.106	2.829
9.322	*******	******	2.986	-15.012	-2.779
9.309	*******	******	9.037	-14.757	2.770
9.297	-284.378	-48.913	3.479	-14.232	-2.582
3.183	-18.102	-3.114	3.085	-14.121	-2.538

A V E R A G E   A C C E L E R A T I O N   F O U R I E R   (860324)

CRD S/N 07   LOC R27   860313   12:02   ROD POS 190"   RUN 01

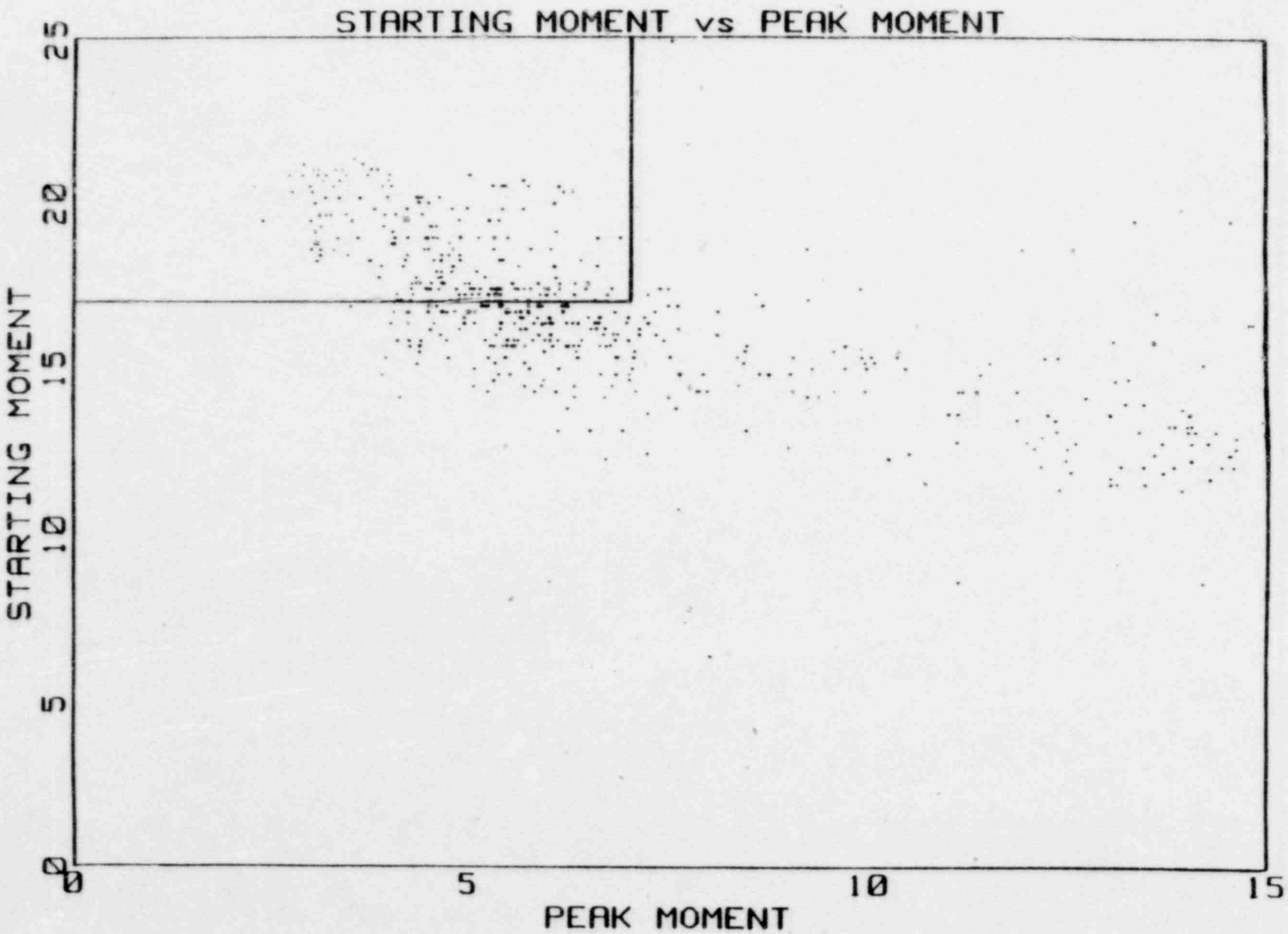
CORE: INLET TEMP 331   MOISTURE 212   SCRAM LENGTH: PART

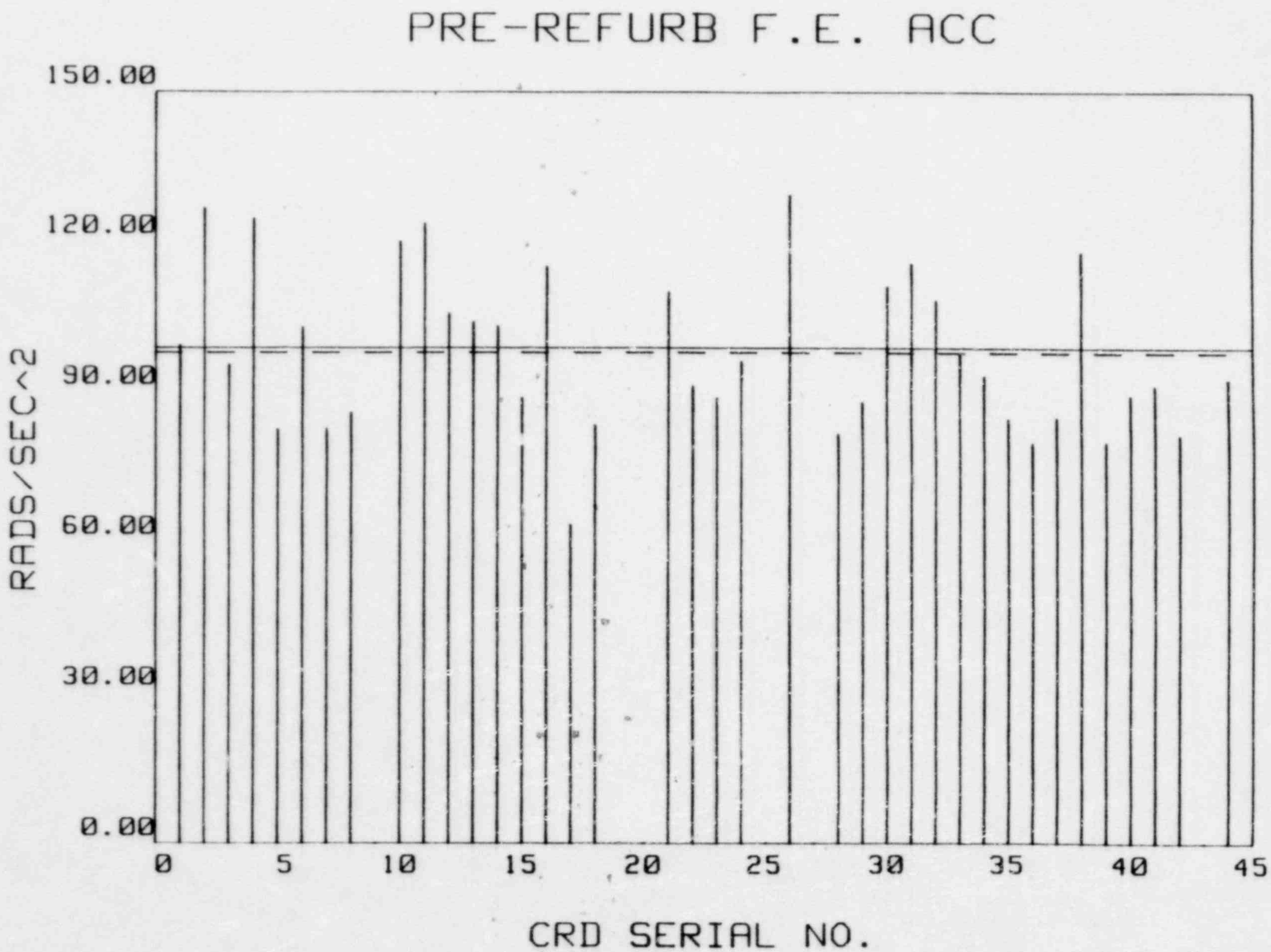
SR 4.1.1 D-X

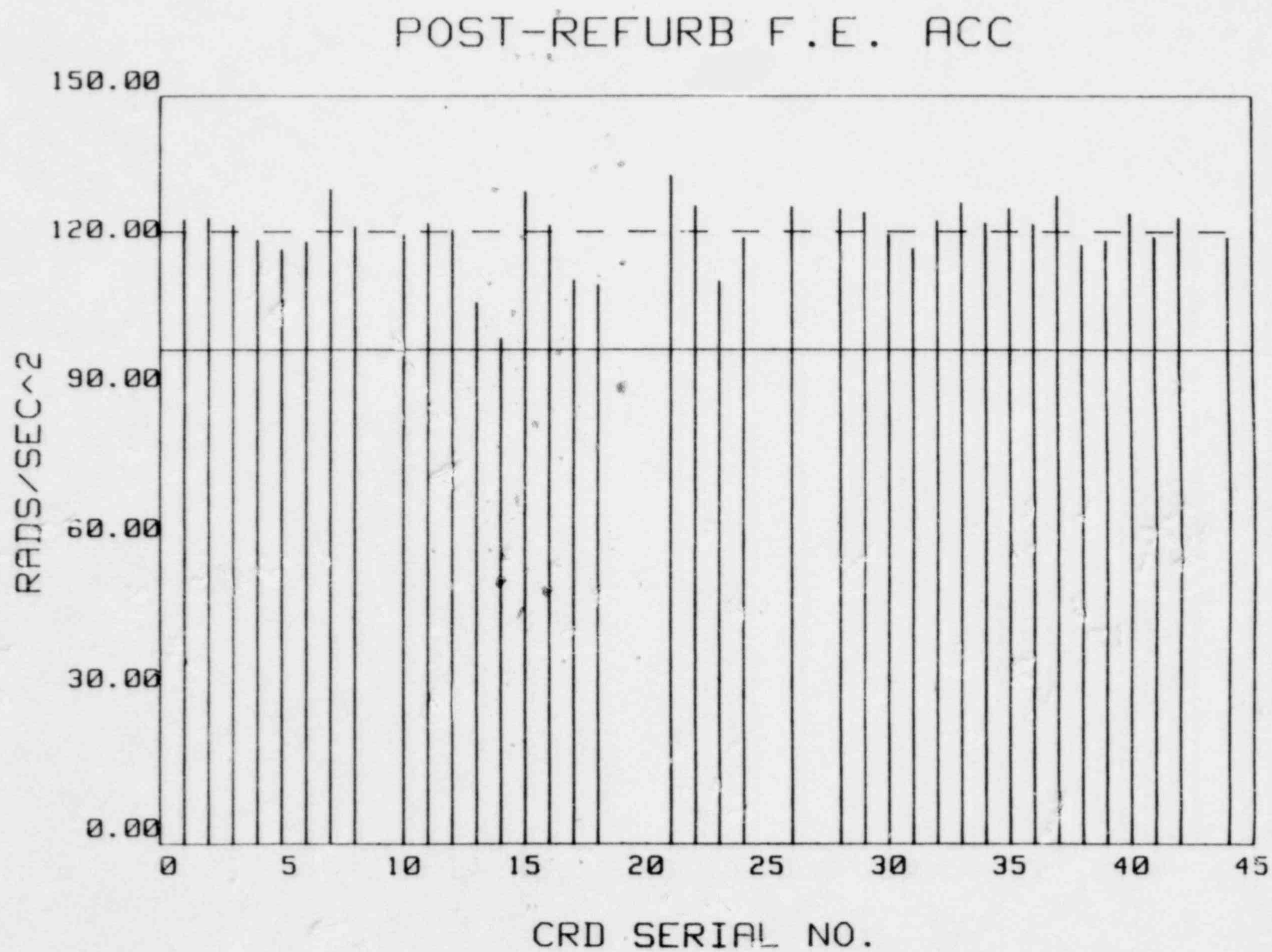


INITIAL ACCEL: 124.86	NUMBER OF SAMPLES: 256	NUMBER OF FOURIERS: 11
PEAK VELOCITY: 277.77	ACCEL SAMPLE RATE: 79.9	PERCENTAGE OVERLAP: 90%
TIME TO PEAK: 2.252	SAMPLE START TIME: 2.95	FREQ RESOLUTION: .3120
STEADY ST TORQ: 0.00	SAMPLE END TIME: 9.30	MAXIMUM FREQNCY: 39.94

	SHAFT	MESH	FREQ	AMPL	FREQ	AMPL
M	40.1921		.62405	1.65132	1.24810	.50955
		562.6887	10.60886	1.26514	22.13861	.50073
1	4.1378		.93608	1.23999	10.92089	.48635
		107.5833	20.90570	.93907	14.66519	.46966
2	.5024		10.29684	.80019	39.93925	.46601
		10.0544	.31203	.70633	19.96962	.46384
3	.2095		3.43228	.70486	21.52975	.43773
		3.1421	9.98481	.69178	21.21772	.38868
D	.0349		20.59367	.60474	33.07469	.38858
			14.35317	.55399	33.38671	.38356


STARTING MOMENT vs PEAK MOMENT
STARTING MOMENT
PEAK MOMENT
0
5
10
15
20
25


PRE-REFURB F.E. ACC
150.00
120.00
90.00
60.00
30.00
0.00
RADS/SEC^2
0
5
10
15
20
25
30
35
40
45
CRD SERIAL NO.


POST-REFURB F.E. ACC
RADS/SEC^2
150.00
120.00
90.00
60.00
30.00
0.00
0
5
10
15
20
25
30
35
40
45
CRD SERIAL NO.

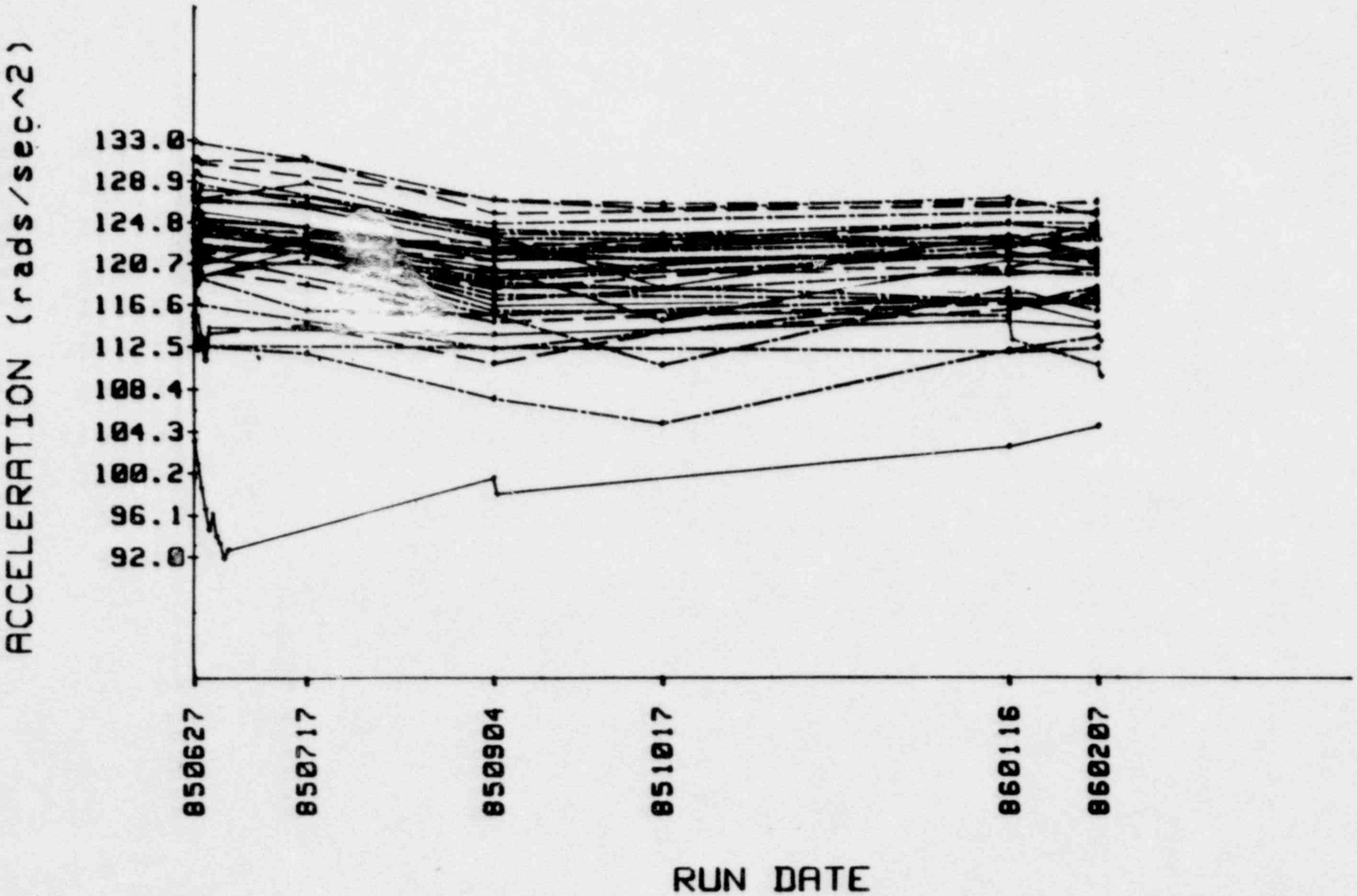
BACK EMF LIMITATIONS

- VELOCITY TO MOTOR REVOLUTION LIMITATION
- MONITOR DYNAMIC NOT STATIC CHARACTERISTICS
- INDIRECT ASSESSMENT THROUGH THE MOTOR

BACK EMF STRENGTHS

- FACILITATES VOLTAGE TRACING COMPARISON
- WAVE FORM DIAGNOSTICS CAN BE PERFORMED
- IMPROVED RETRIEVABILITY AND PERFORMANCE TRENDING
- BOTH MECHANICAL AND ELECTRICAL CHARACTERISTICS ARE MONITORED
- WEEKLY SURVEILLANCE PROVIDES SUFFICIENT INFORMATION

CRD FRONT END ACCELERATION



PLANNED

RESEARCH AND DEVELOPMENT

- VARIABLE WEIGHT DROP TEST
- TORQUE IMBALANCE TEST
- THREE PHASE VOLTAGE TEST
- MOMENT VERIFICATION TEST

RESERVE SHUTDOWN MATERIAL CHANGEOUT

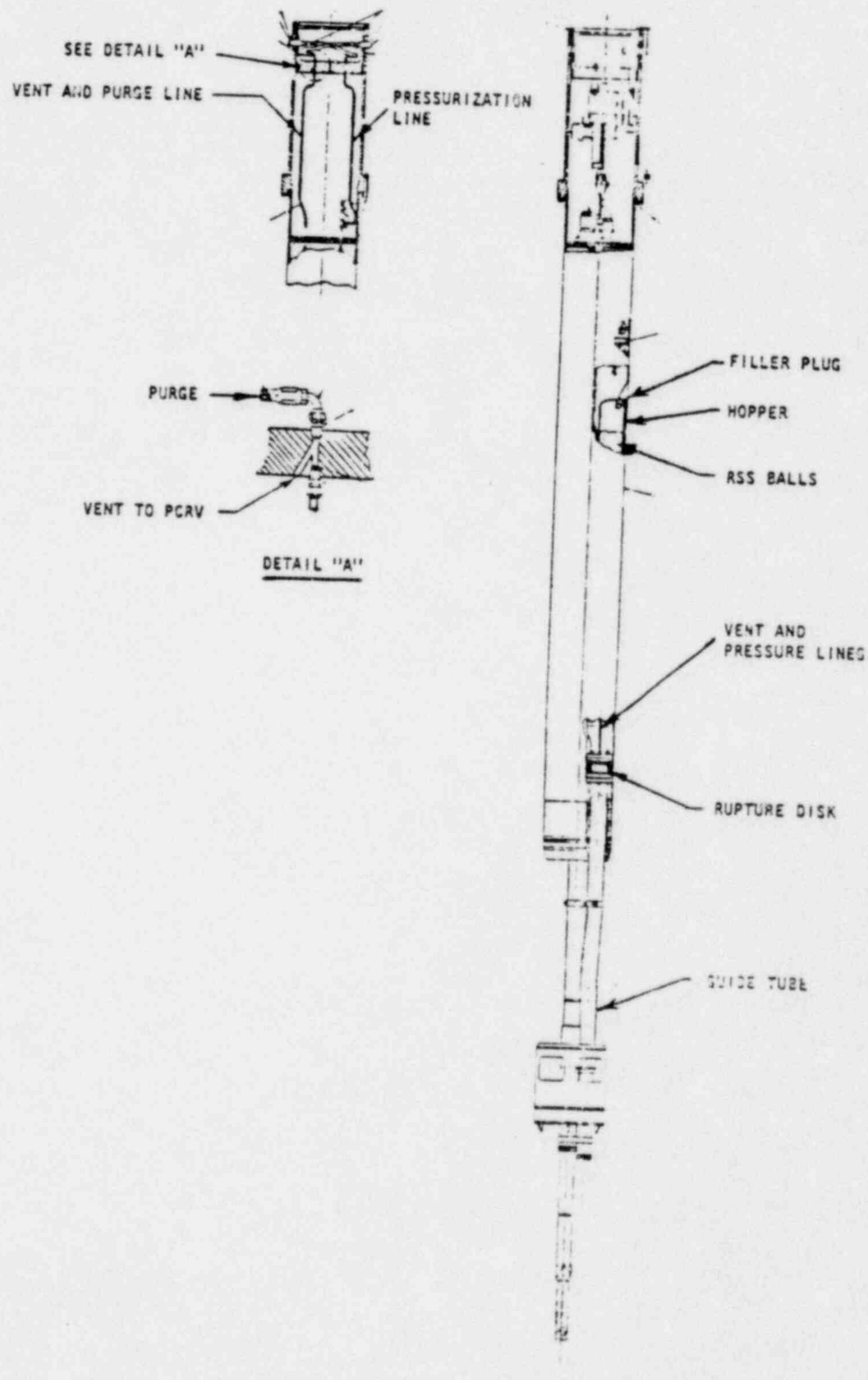


Fig. 1. Reserve shutdown system

FIGURE 2

RESERVE SHUTDOWN MATERIAL TAKEN FROM CRDOA 21 (REGION 35)

	20 w/o BORON	40 w/o BORON
** UCC MATERIAL	0.459	0.815
** ART MATERIAL	0.021	0.068

**

UCC - UNION CARBIDE CORPORATION

ART - ADVANCED REFRACTORY TECHNOLOGIES

B_2O_3 RESIDUAL CONTENT (w/o)*

FIGURE 3

*PERCENT OF TOTAL RSS BALL WEIGHT

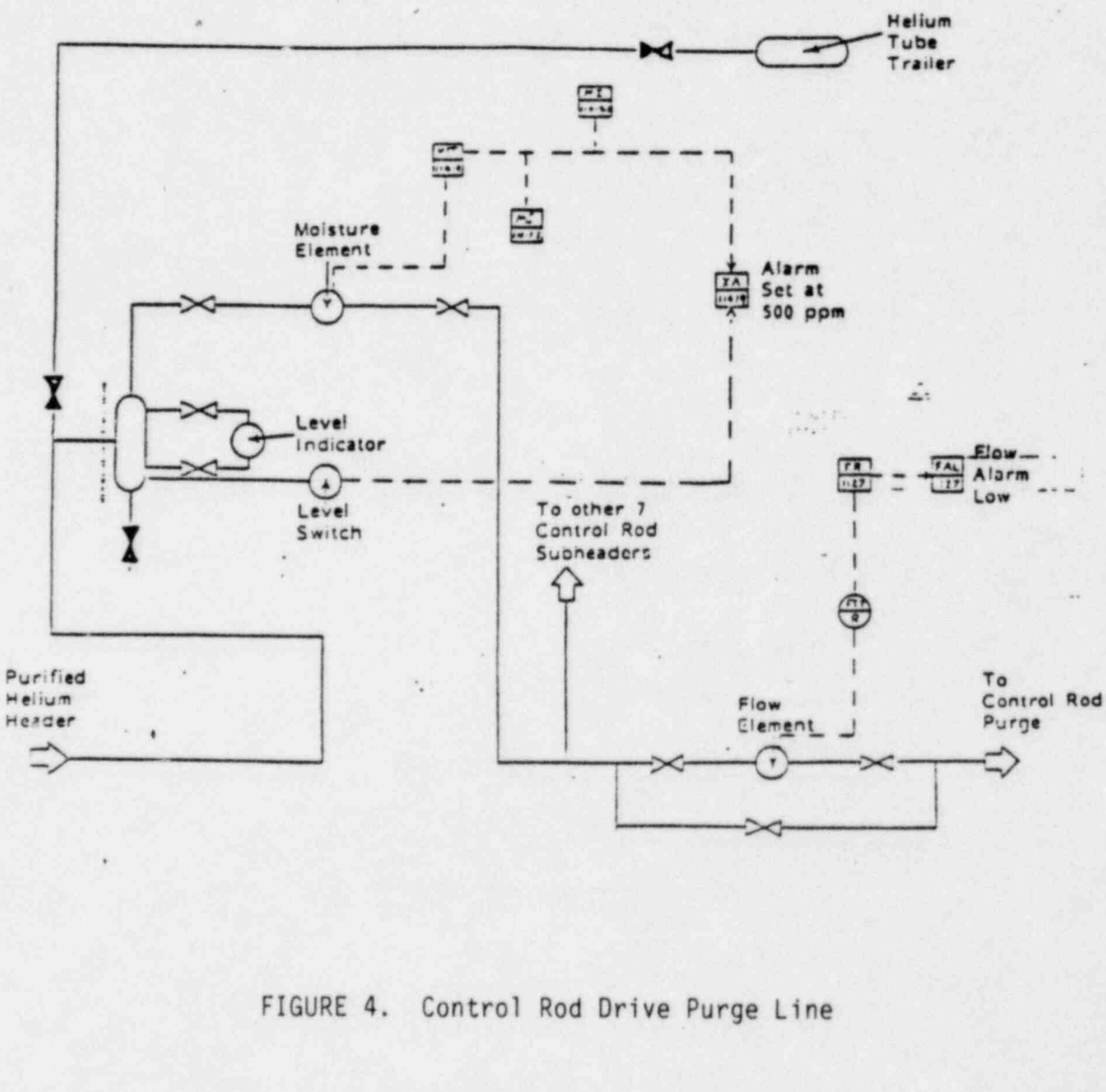


FIGURE 4. Control Rod Drive Purge Line

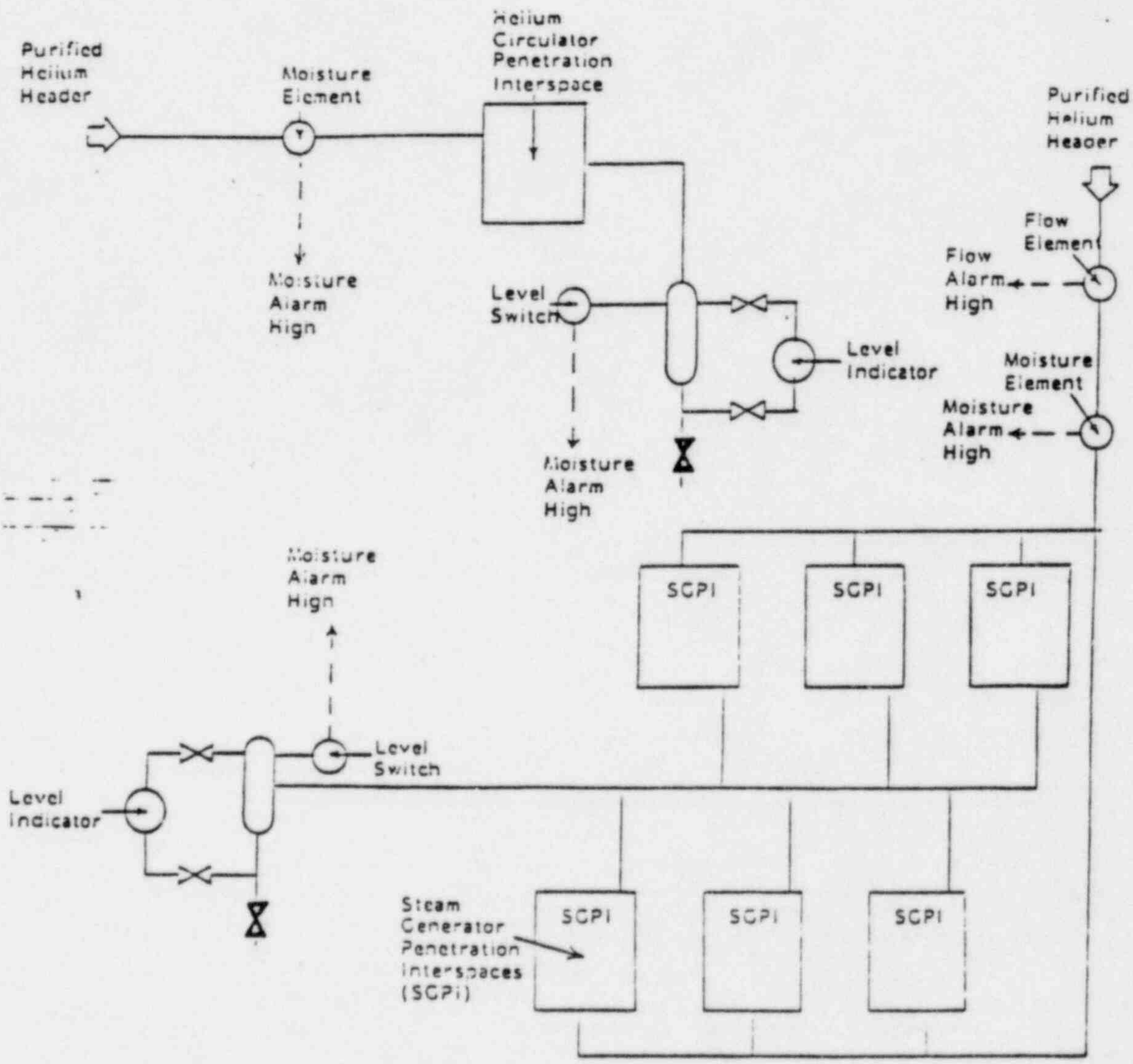


Figure 5. Helium Circulator and Steam Generator Penetration Interspace Knock-Out Pots

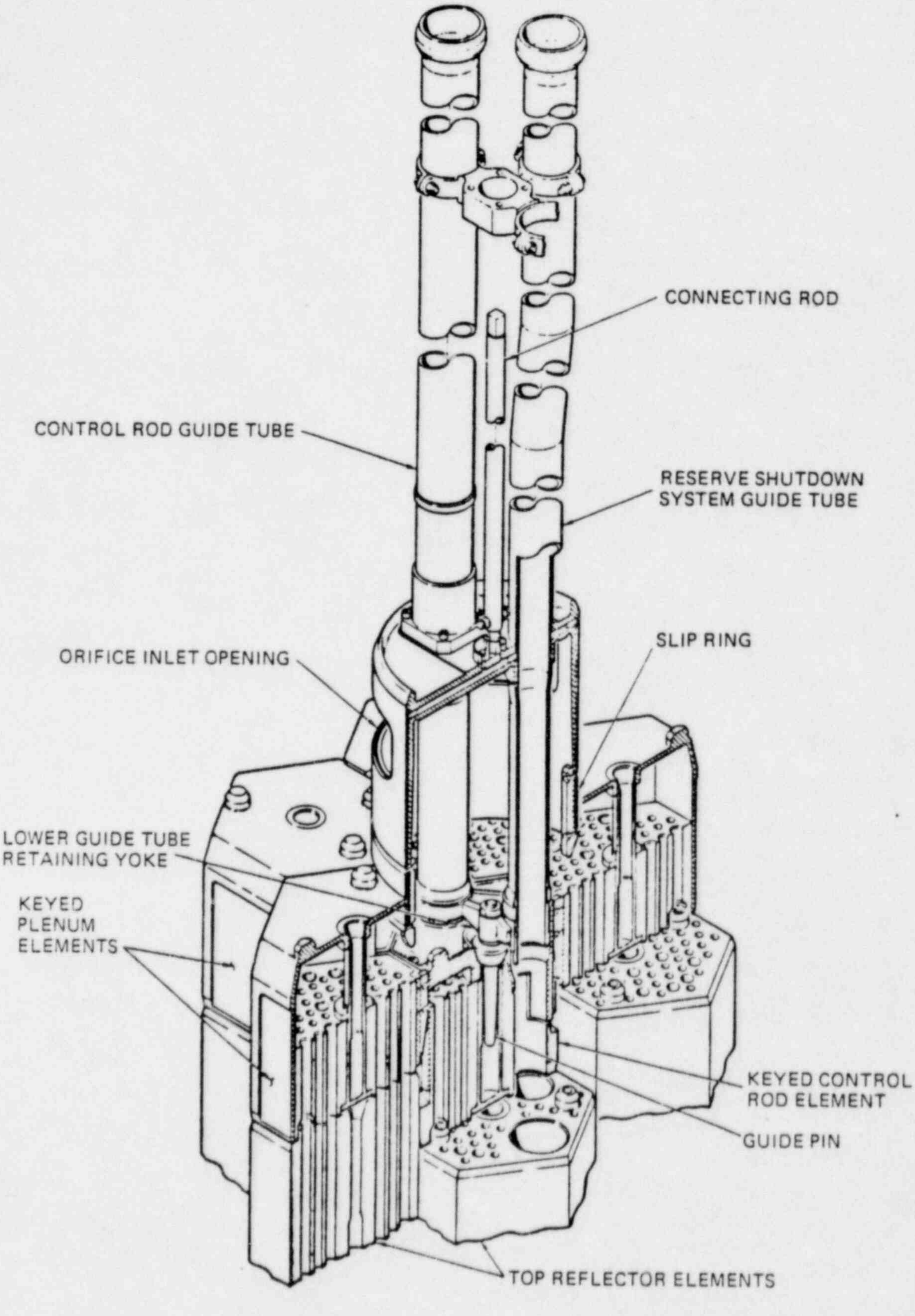


Figure 6 Top Plenum and Orifice Valve Arrangement

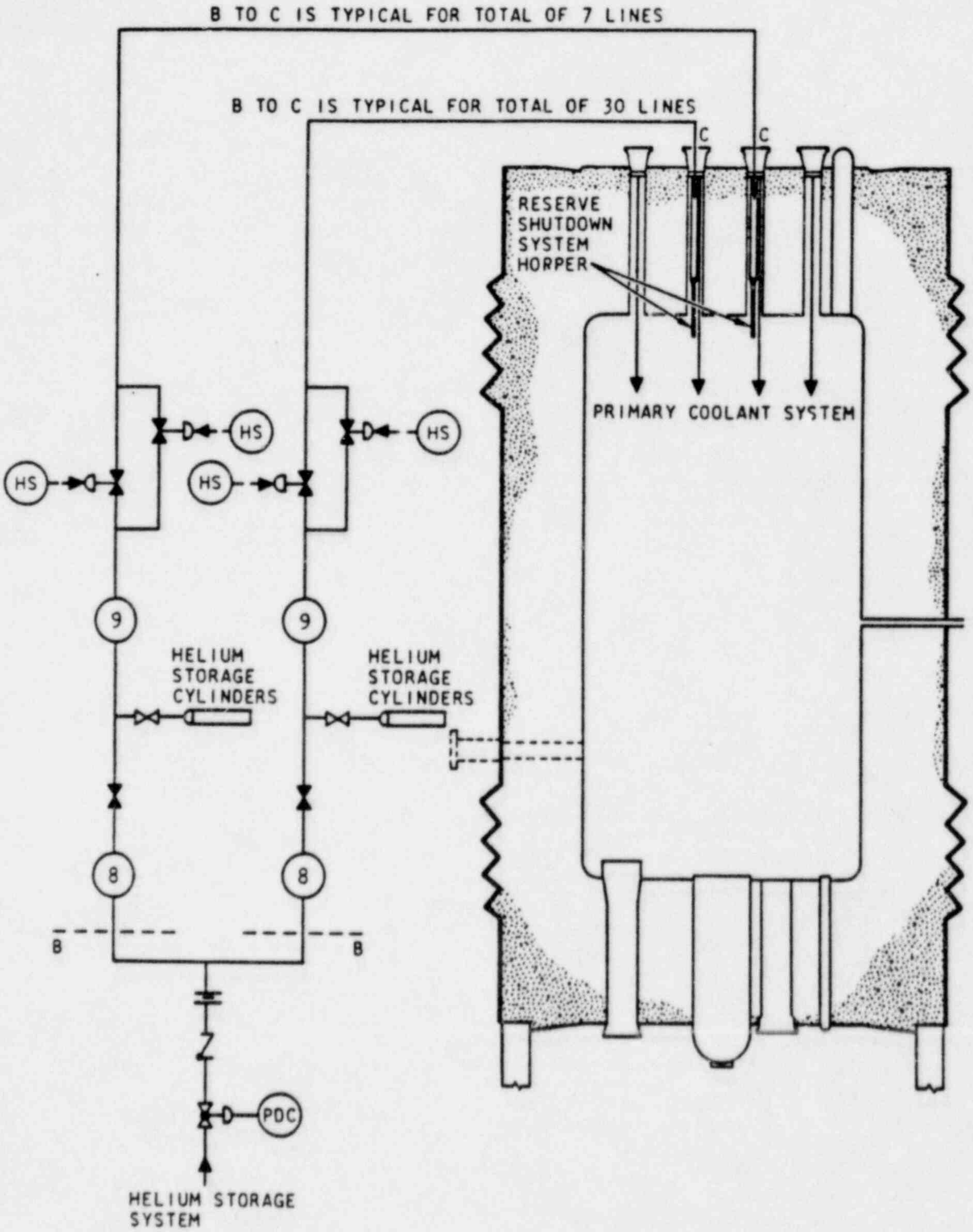


Figure 7 Reserve Shutdown System Flow Diagram

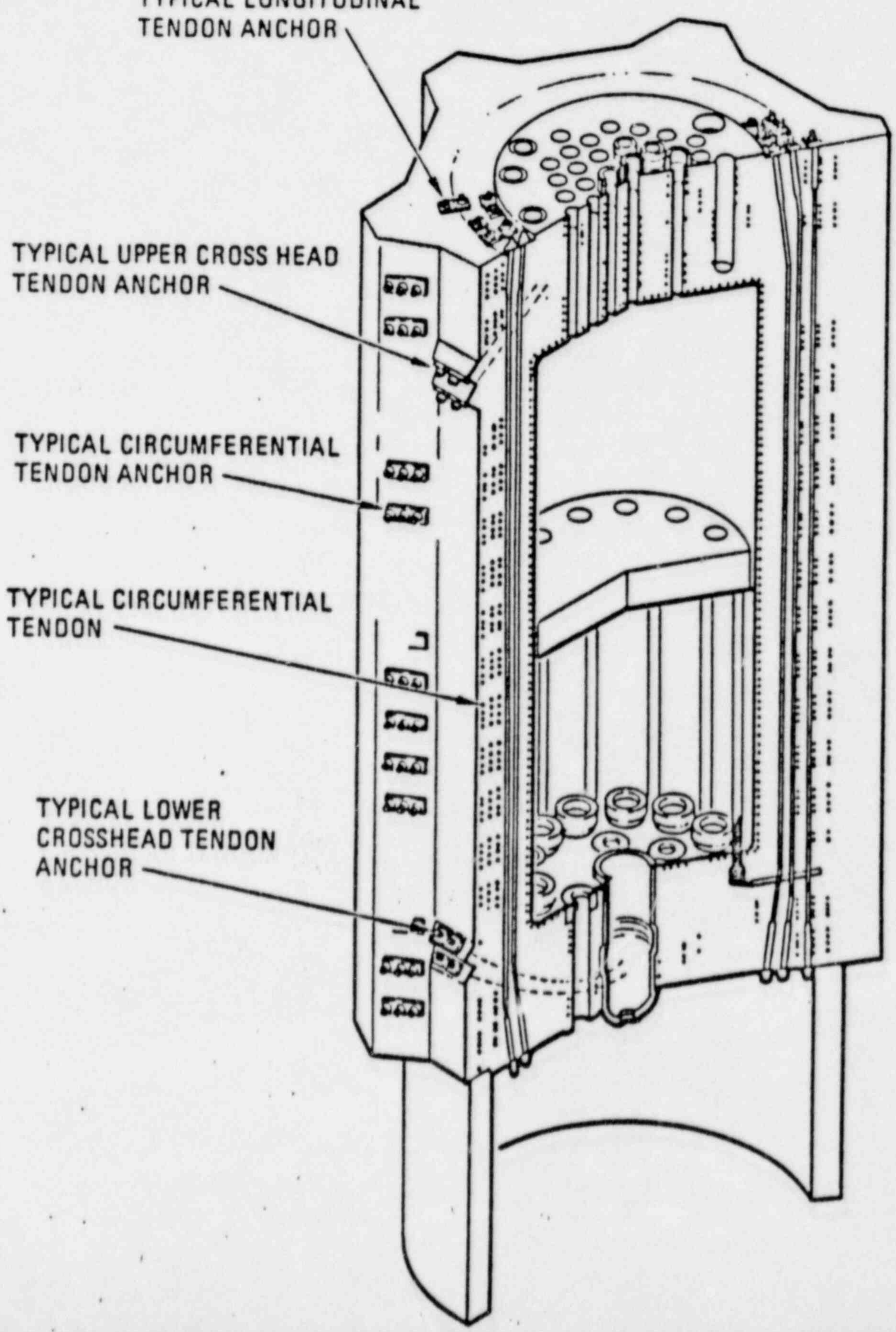
PCRV TENDON CORROSION PROBLEMS AND CORRECTIVE ACTIONS

FORT ST VRAIN

PCRV

PRESTRESSING TENDON SYSTEM

- GENERAL PCRV PRESTRESSING SYSTEM OVERVIEW
- SURVEILLANCE PROGRAM
- METALLURGICAL ASPECTS OF TENDON CORROSION
- TENDON SURVEILLANCE RESULTS
- REMEDIAL MEASURES AND PLANNED ACTIONS


TYPICAL LONGITUDINAL TENDON ANCHOR
TYPICAL UPPER CROSS HEAD TENDON ANCHOR
TYPICAL CIRCUMFERENTIAL TENDON ANCHOR
TYPICAL CIRCUMFERENTIAL TENDON
TYPICAL LOWER CROSSHEAD TENDON ANCHOR

CALCULATED STRESS VS ALLOWABLE STRESS

AT 2.1 REFERENCE PRESSURE

	CALCULATED STRESS ksi	ALLOWABLE STRESS ksi	PERCENT MARGIN
o LONGITUDINAL	156	204	24 %
o CIRCUMFERENTIAL BARREL	170	204	17 %
o CIRCUMFERENTIAL HEAD	138	0.9x204	25 %
o CROSS HEAD	139	0.9x204	24 %

SURVEILLANCE CRITERIA

PERCENT NON-EFFECTIVE WIRES

o LONGITUDINAL	20 %
o CIRCUMFERENTIAL BARREL	15 %
o CIRCUMFERENTIAL HEAD	20 %
c CROSS HEAD	20 %

TENDON VISUAL INSPECTION PROGRAM

TENDON GROUPS	TOTAL NUMBER OF NEW TENDONS	TOTAL NUMBER OF CONTROL TENDONS	TOTAL NUMBER OF TENDONS
CIRCUMFERENTIAL	13	3	16
TOP CROSS HEAD	1	1	2
BOTTOM CROSS HEAD	6	2	8
LONGITUDINAL	24	6	30

TENDON LIFTOFF PROGRAM

TENDON GROUPS	TOTAL NUMBER OF NEW TENDONS	TOTAL NUMBER OF CONTROL TENDONS	TOTAL NUMBER OF TENDONS
CIRCUMFERENTIAL	13	3	16
TOP CROSS HEAD	1	1	2
BOTTOM CROSS HEAD	3	1	4
LONGITUDINAL	12	3	15

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EVALUATION OF THE CAUSES OF CORROSION IN THE FORT ST. VRAIN POST-TENSIONING TENDON WIRES

H-036(14)
1-23-85

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- DURING SCHEDULED SURVEILLANCE APRIL 1984 FRACTURED AND SEVERELY CORRODED WIRES WITHIN SEVERAL TENDONS WERE OBSERVED

- TECHNICAL STUDIES WERE INITIATED BY GA & PSC TO DETERMINE POSSIBLE CAUSE OF CORROSION AND FAILURES

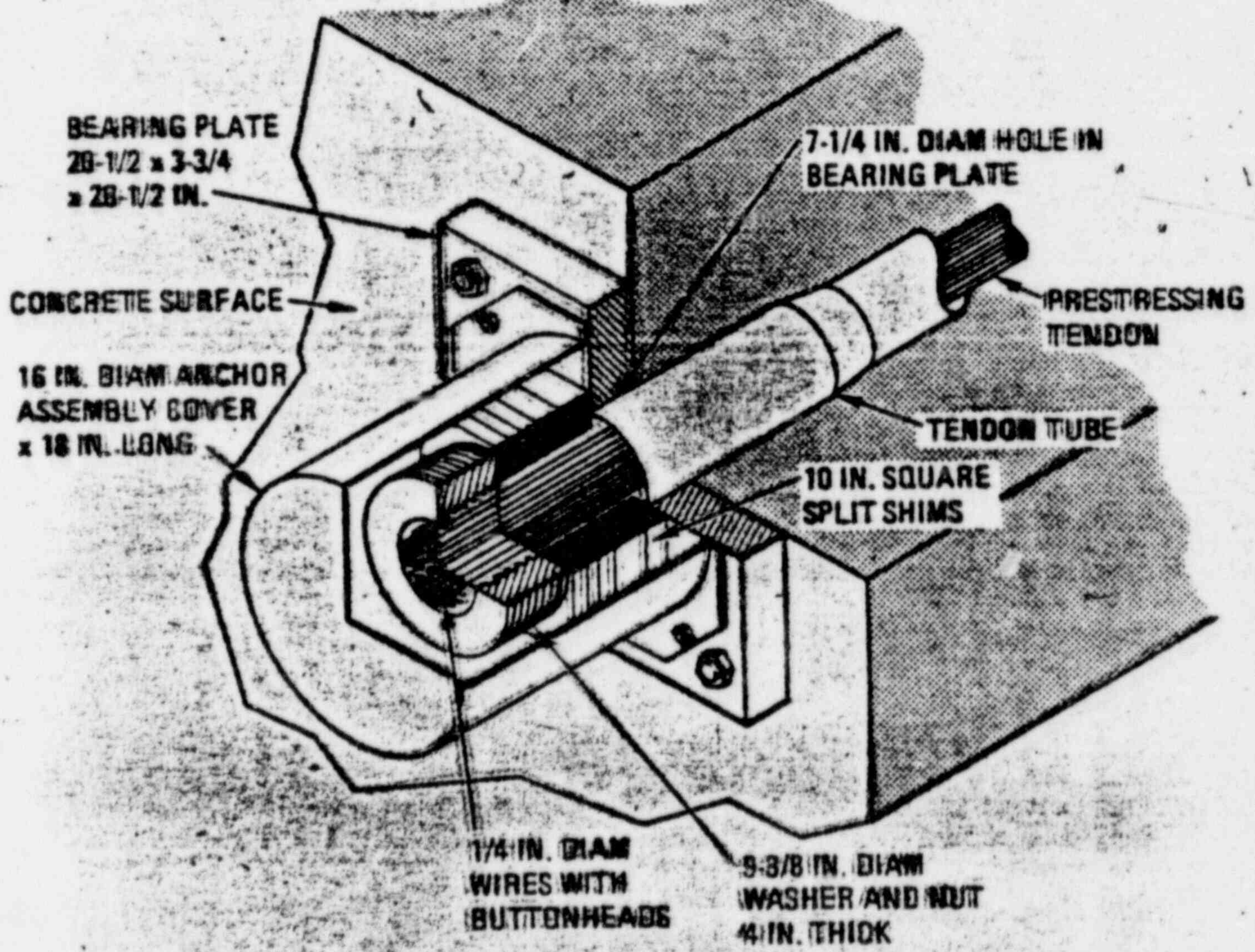

Fig. 2. Tendon end anchor assembly arrangement.

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BACKGROUND (CONTINUED)

- CORRESION PROTECTION
  - WIRES COATED WITH METABOUND 39 (A CALCIUM ZINC PHOSPHATE COATING) AND RUSTAREST 452 WHICH SEALS THE PHOSPHATE COATING. WIRES WERE ALSO COATED WITH NO-OX-ID CM CASING FILLER
- NO-OX-ID IS A PETROLEUM BASE GREASE-LIKE COMPOUND CONTAINING ADDITIVES OF LANOLIN AND SODIUM PETROLEUM SULPHONATE
- TENDON WIRE END WASHER ASSEMBLIES WERE ENCLOSED BY STEEL SHEET ANCHOR CAPS TO PREVENT INJURIOUS ENVIRONMENTS FROM CONTACTING THE TENDONS

H-036(21)
1-23-85

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ANALYSIS METHODS

- VISUAL
- X-RAY DIFFRACTION
- GREASE ANALYSIS
- TENSILE TESTS
- METALLOGRAPHIC EXAMINATION
- SCANNING ELECTRON MICROSCOPY/EDAX
- MICROBIOLOGICAL CORROSION ANALYSIS

H-036(1)
1-23-85

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VISUAL

H-036(11)
1-23-85

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VISUAL

- VISUAL EXAMINATION OF BROKEN WIRES SHOWED CONCENTRATIONS OF CORROSION ADJACENT TO AND AT FRACTURE FACE
- CORROSION LOCALIZED TO WITHIN 12 IN. OF STRESSING WASHER ON VERTICAL TENDONS AND 36 IN. ON BOTTOM CROSSHEAD TENDONS
- ONE NONCORRODED WIRE REMOVED FROM A LONGITUDINAL AND BOTTOM CROSSHEAD TENDON WAS INSPECTED. NO CORROSION WAS OBSERVED
- ALL THE FAILED WIRES WERE REMOVED FROM BI-U3 AND INSPECTED. CORROSION WAS LIMITED TO WITHIN 12 IN. OF THE STRESSING WASHER. CORROSION IN EARLY STAGES WAS OBSERVED AS FAR AS 8 FT FROM THE BUTTONHEAD.
- CORROSION NOT EVIDENT ON ALL WIRES WITHIN BUNDLE
- CORROSION PRODUCT REDDISH ORANGE TO DARK BROWN

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1-23-85

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METALLOGRAPHIC EXAMINATION

H-036(10)
1-23-85

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METALLOGRAPHIC RESULTS

- METALLOGRAPHIC EXAMINATION OF BROKEN TENDON WIRES SHOWED SOME FAILURES TO BE NEW AND SOME OLD
- EVIDENT THAT CORROSION CONTINUED AFTER FRACTURE
- CORROSION AT THE FRACTURE FACE IN MOST CASES FOLLOWED THE MNS STRINGER INCLUSIONS IN THE STEEL
- STRESS CORROSION CRACKING AND PITTING WAS OBSERVED IN SOME OF THE SAMPLES LOCATED IN THE REGION OF SURFACE CORROSION
- NO STRESS CORROSION CRACKING OCCURRED OUTSIDE AREA OF SURFACE CORROSION
- IN ALL CASES CRACK PROPAGATION WAS PERPENDICULAR TO THE APPLIED TENSILE LOADING

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SCANNING ELECTRON MICROSCOPY/EDAX

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1-23-85

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SEM OBSERVATIONS

- EXAMINATIONS WERE PERFORMED ON
  - FAILED WIRES
  - WIRES THAT FAILED DURING LIFTOFF
  - FRACTURE FACES OF TENSILE TEST SPECIMENS

- CORROSION CONTINUED AFTER FAILURE

- FRACTURE MORPHOLOGY OF FAILED WIRES DIFFICULT TO DETERMINE DUE TO CORROSIVE ATTACK AFTER FAILURE

- WIRES INDICATED PRIMARY CAUSE OF FAILURE WAS DUE TO A TENSILE OVERLOAD

- EDAX INDICATED MAJOR ELEMENT IN CRACKS EMANATING FROM PITS WAS IRON

- NO EVIDENCE OF EMBRITTLEMENT OR STRESS CORROSION CRACKING ON FRACTURE FACES

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CORROSION TESTING

- INCUBATION AMPULES MAINTAINED AT 100°F WERE UTILIZED WITH THE FOLLOWING SAMPLES SIMULATING OPERATING CONDITION

  (A) GREASE FROM CORRODED END OF CORRODED TENDON + H_2O

  (B) AS IN (A) EXCEPT GREASE FROM UNCORRODED END

  (C) DUPLICATE OF (A)

  (D) OIL RESIDUE REMOVED FROM TENDON CAPS

  (E) PORTIONS OF THE ABOVE GREASES STERILIZED AND USED AS CONTROL SAMPLES

  (F) H_2O ONLY

RESULTS

ALL EXCEPT (B) CORRODED

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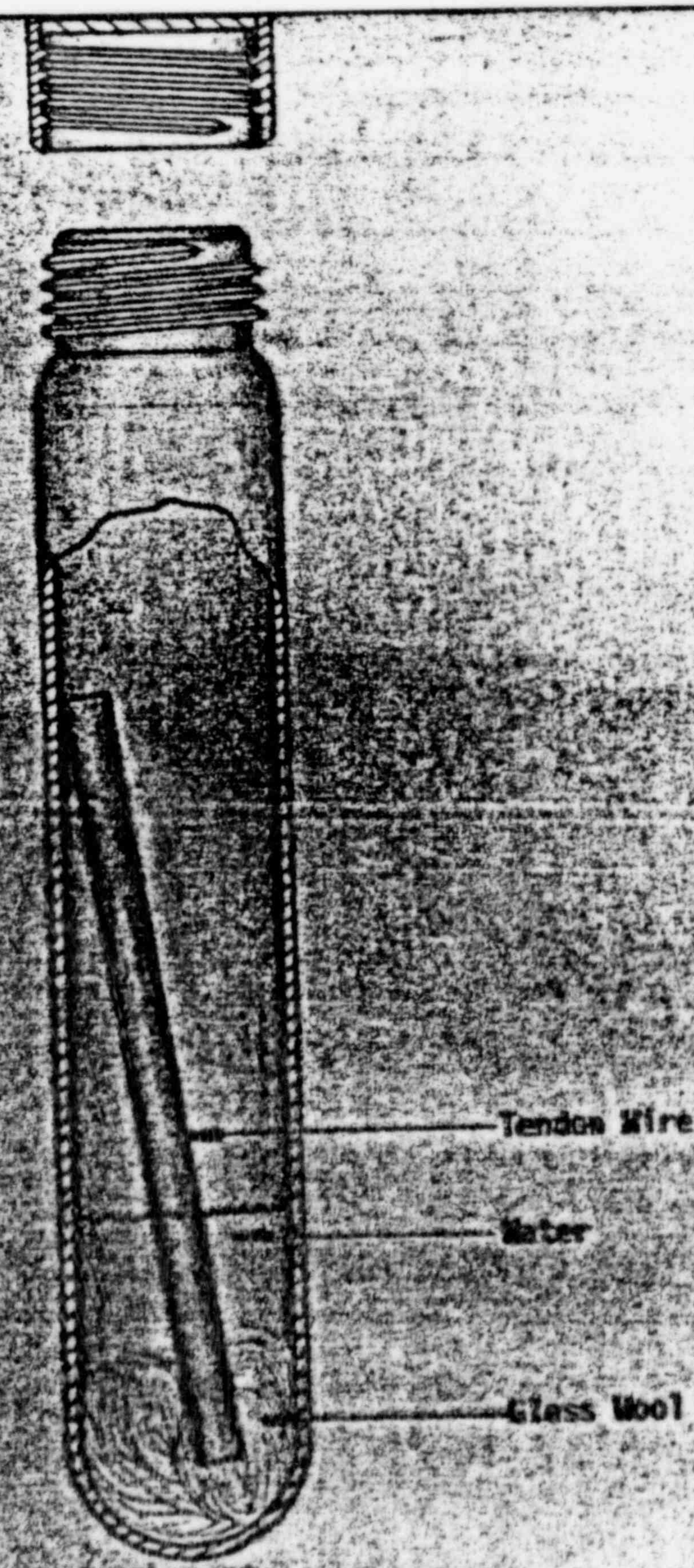

Figure 48 - Typical Corrosion Test Tube Configuration

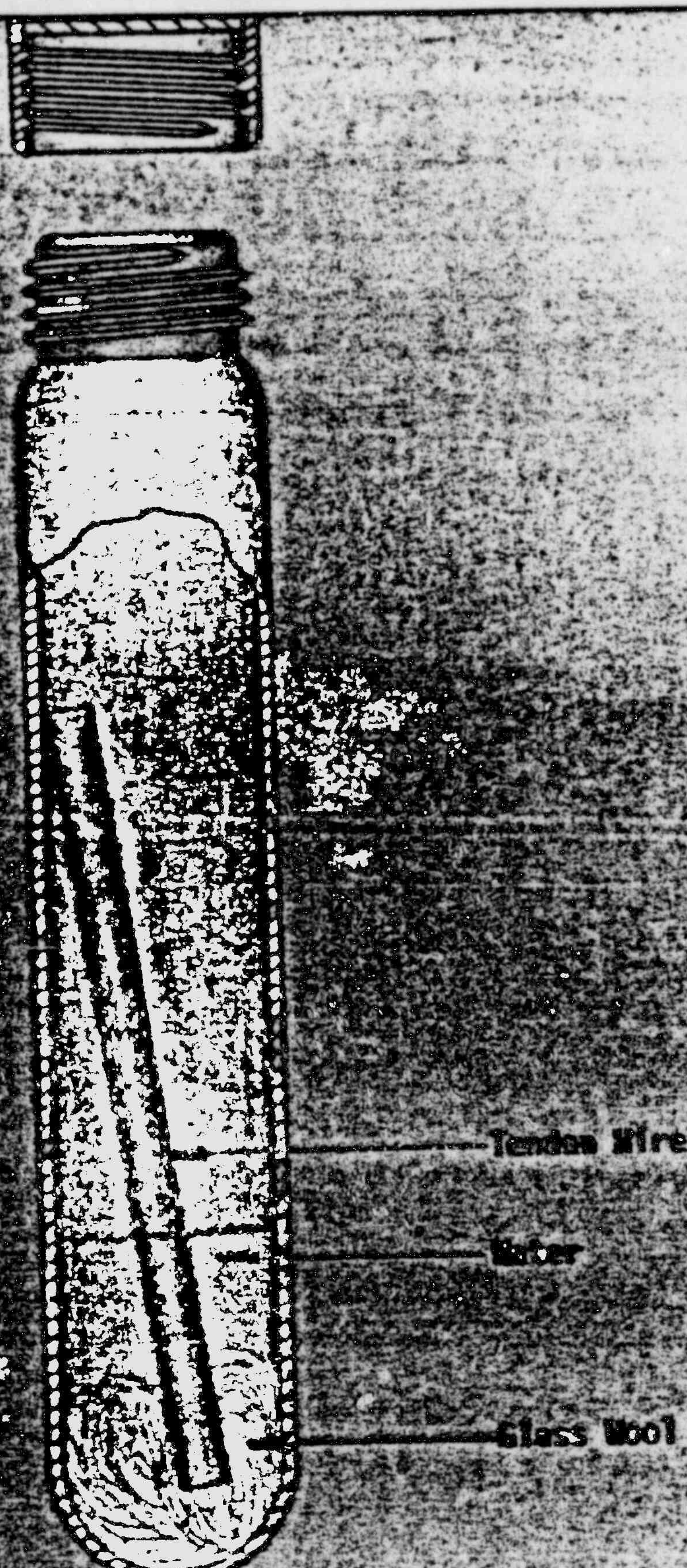

Figure 48 - Typical Corrosion Test Tube Configuration

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GREASE AND CORROSION PRODUCT ANALYSIS

- GREASE AND CORROSION PRODUCT REMOVED FROM CORRODED END OF TENDON WIRE SHOWED SIGNIFICANT QUANTITIES OF CARBOXYLIC ACIDS (ACETATE AND FORMATE)

  — ACETIC 60 TO 23,000 MICROGRAMS/GRAM

  — FORMIC 50 TO 2,000 MICROGRAMS/GRAM

- ACETIC AND FORMIC ACIDS WERE PRESENT IN CORROSION PRODUCT REMOVED FROM CORROSION TEST SPECIMENS

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MICROBIOLOGICAL CORROSION ANALYSIS

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1-23-85

TENDON INCUBATION TEST SAMPLE ATMOSPHERE ANALYSIS

- GAS ANALYSIS WAS PERFORMED ON TENDON ATMOSPHERES DURING SURVEILLANCES FROM 1971–1984. IN ALL CASES THE GAS ANALYSIS INDICATED AN INCREASE IN H_2, CO_2 AND N_2 AND A DECREASE IN O_2

- SIMILAR RESULTS AS ABOVE

- CHANGES IN TENDON GAS ANALYSIS OVER THE YEARS IS CONSISTENT WITH MICROBIOLOGICAL DEGRADATION OF THE GREASE (MIXED ACID FERMENTATION)

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MICROBIOLOGICAL CORROSION

- CONSIDERED TO BE A VIABLE CORROSION MECHANISM BECAUSE TENDON ENVIRONMENT CONTAINS FACTORS KNOWN TO BE CONDUCIVE TO MICROBIOLOGICAL GROWTH
  - WARM (100°F)
  - MOIST
  - CONTAINS NUTRIENTS (ORGANIC GREASE)
  - REMAINS RELATIVELY UNDISTURBED FOR LONG PERIODS
  - OXYGEN

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1-23-85

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ANALYTICAL METHODS

- MICROBIOLOGICAL EXAMINATION UTILIZING DIRECT MICROSCOPIC EXAMINATION AND CULTURING PERFORMED BY MICROBIOLOGICAL CORROSION EXPERT (D. POPE RPI)
- TESTING SIMULATING ENVIRONMENTAL CONDITIONS WHICH HAVE CAUSED TENDON WIRE CORROSION
- GREASE AND CORROSION PRODUCT ANALYSIS
- TENDON ATMOSPHERE ANALYSIS
- OTHER CORROSION TESTS PERFORMED

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CONCLUSIONS OF MICROBIOLOGICAL ANALYSIS

- DIRECT MICROSCOPIC EXAMINATION FOR TOTAL BACTERIA FOUND LARGE NUMBERS OF BACTERIA THAT WERE NOT GENERALLY CULTURABLE
- THE TENDON SYSTEM HAS ALL OF THE REQUIRED NUTRIENTS FOR GROWTH OF ORGANISMS; ORGANIC SULFONATE GREASE WITH A NEUTRAL PH, OXYGEN, WARMTH (100°F) AND MOISTURE
- SULFATE REDUCING BACTERIA WAS NOT THE PRIMARY CAUSE OF CORROSION IN THE TENDONS
- THE DETECTION OF ORGANIC ACIDS AS WELL AS ELEVATED AMOUNTS OF CO_2, H_2 AND DECREASED AMOUNTS OF O_2 IN THE TENDON SYSTEM INDICATE THAT MICROBES HAVE BEEN ACTIVE IN THE SYSTEM

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CONCLUSIONS OF MICROBIOLOGICAL ANALYSIS (CONTINUED)

- CORROSION TESTING PERFORMED WITH STERILE AND NON-STERILE GREASES REPRODUCED CORROSION WHICH HAD OCCURRED IN THE TENDONS. IN ADDITION, CORROSION TESTING PERFORMED WITH ACETIC AND FORMIC ACID MOIST ENVIRONMENTS PRODUCED CORROSION IDENTICAL TO CORROSION TESTING PERFORMED WITH GREASES

- THE ABSENCE OF VIABLE BACTERIA IS NOT INCONSISTENT WITH MICROBIOLOGICAL INFLUENCED CORROSION SINCE MICROBES MAY BE AT SITES OTHER THAN AREAS OF CORROSION. THE ACIDS PRODUCED BY THESE MICROBES WHICH CAUSE THE CORROSION MAY ALSO HAVE KILLED THE MICROBES

H-036(7)
1-23-85

CONCLUSIONS

- Formic and acetic acids were produced as a result of microbiological activity breaking down the NO-OX-ID CM organic grease.

- The formic and acetic acids vaporized and condensed along with moisture on uncoated areas of the tendon wires resulting in severe general corrosion and pitting. Stress corrosion cracking is also thought to have occurred due to formic and acetic acid.

- The final failure mechanism was tensile overload resulting from reduced cross sectional area due to corrosion. Failures originating at stress corrosion cracks are also assumed to have occurred.

TENDON VISUAL INSPECTION PROGRAM

TENDON GROUPS	TOTAL NUMBER OF NEW TENDONS	TOTAL NUMBER OF CONTROL TENDONS	TOTAL NUMBER OF TENDONS
CIRCUMFERENTIAL	13	3	16
TOP CROSS HEAD	1	1	2
BOTTOM CROSS HEAD	6	2	8
LONGITUDINAL	24	6	30

TENDON LIFTOFF PROGRAM

TENDON GROUPS	TOTAL NUMBER OF NEW TENDONS	TOTAL NUMBER OF CONTROL TENDONS	TOTAL NUMBER OF TENDONS
CIRCUMFERENTIAL	13	3	16
TOP CROSS HEAD	1	1	2
BOTTOM CROSS HEAD	3	1	4
LONGITUDINAL	12	3	15

INTERIM SURVEILLANCE PROGRAM

CONTROL TENDONS

TENDON	NUMBER OF SURVEILLANCES	ADDITIONAL NON-EFFECTIVE WIRES
CM 1.1	2	0
CO 14.4	2	0
CM 16.3	2	0
TIRM2	2	0
BIRM4	4	0
BILM3	4	0
VM-10	4	4
VI-20	4	0
VM-20	4	0
VM-37	4	0
VI-40	4	0
VM-40	4	0

TENDONS WITH ADDITIONAL

NON-EFFECTIVE WIRES

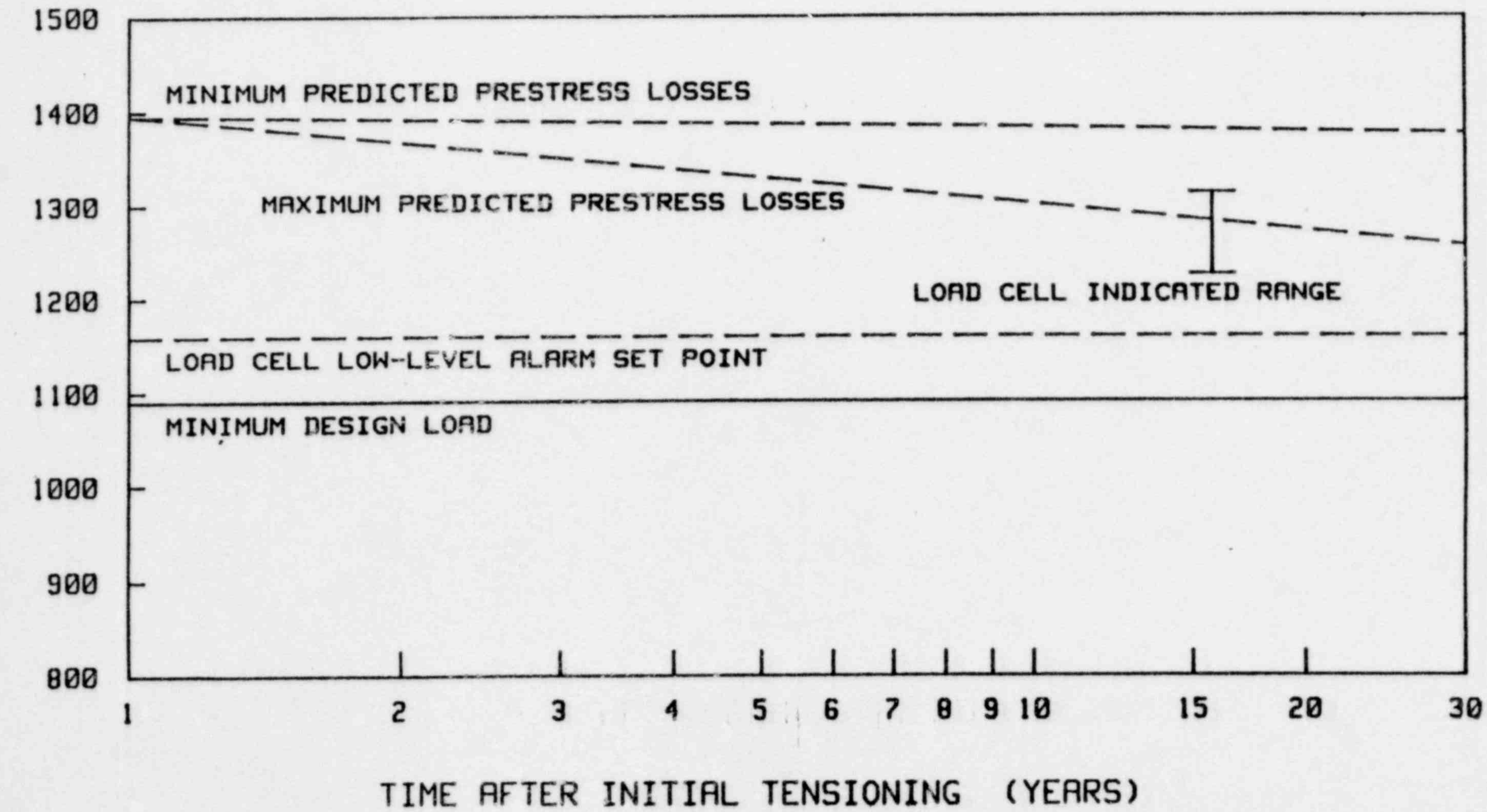
TENDON	DATE	NON-EFFECTIVE WIRES
	CONTROL GROUP	
VM-10	4/84	3
	1/85	7
	NON-CONTROL GROUP	
VM-08	4/84	3
	1/85	4
VM-17	4/84	5
	1/85	6
VM-30	4/84	21
	1/85	22
VI-35	4/84	0
	1/85	1
VM-42	4/84	1
	1/85	2
BILU3	4/84	12
	3/85	20
BIRU3	4/84	0
	3/85	1
BILU4	5/84	24
	6/84	28
BILL3	4/84	0
	3/85	1
BORM4	4/84	1
	3/85	3

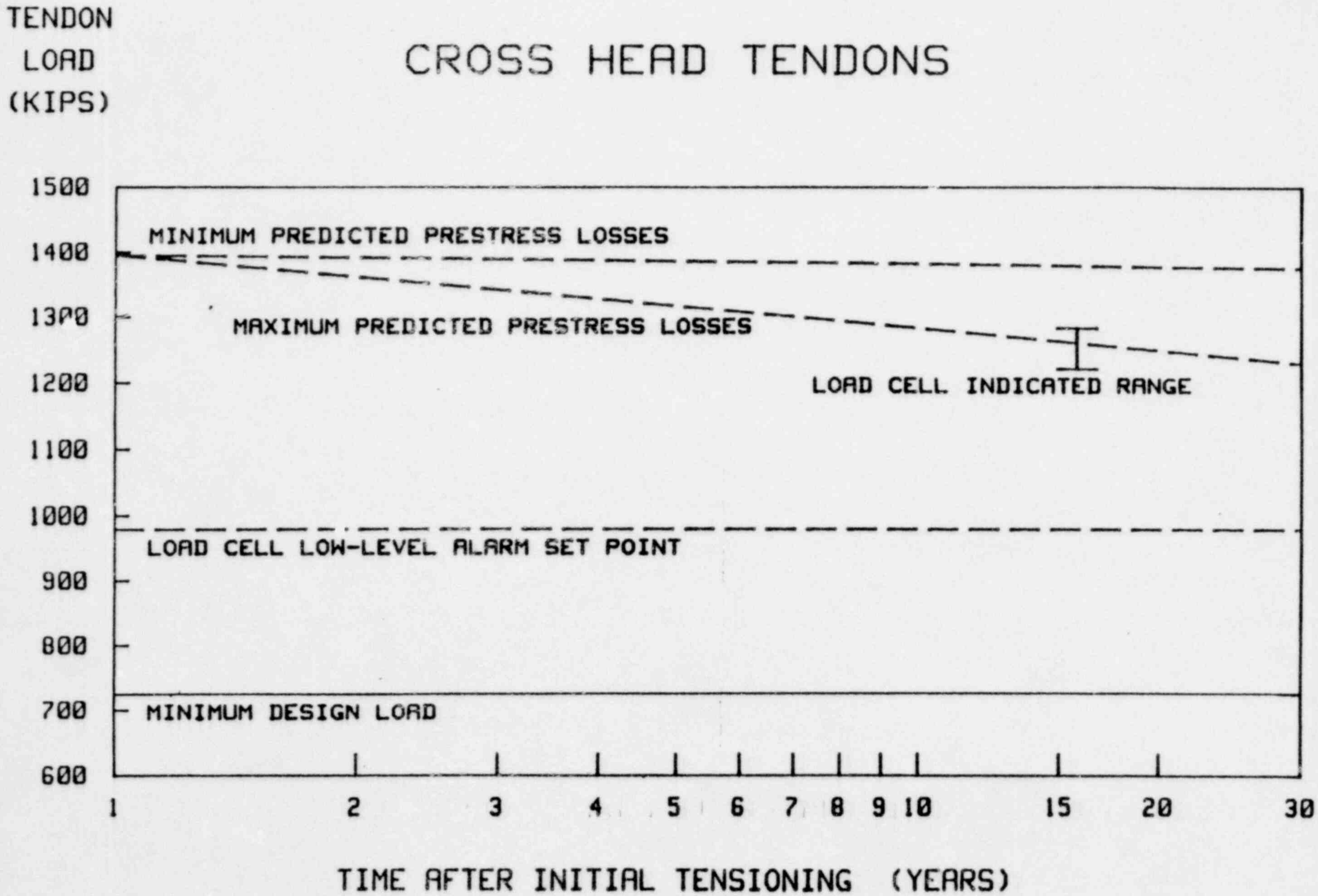
TENDON SURVEILLANCE SUMMARY

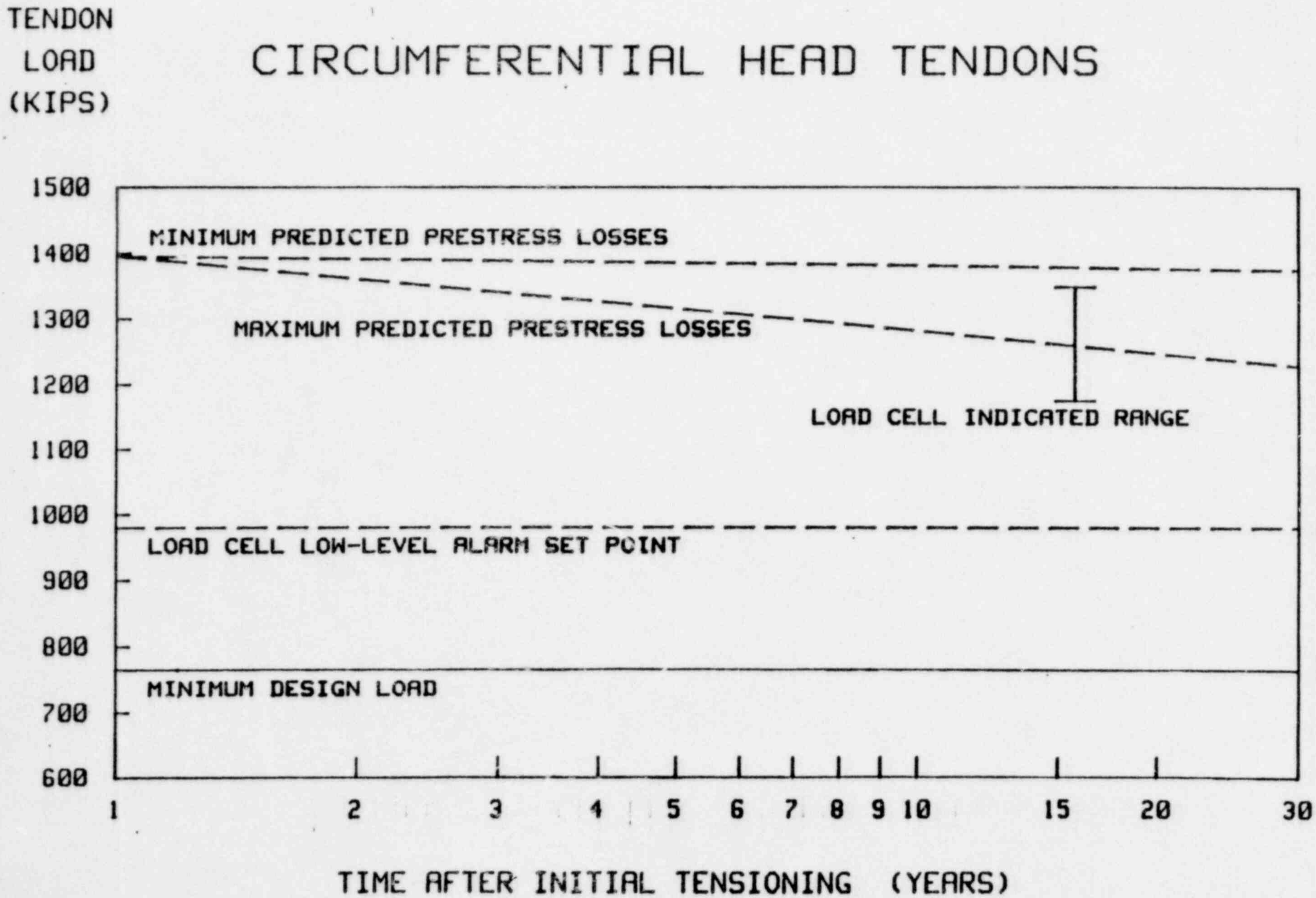
FEBRUARY 1986

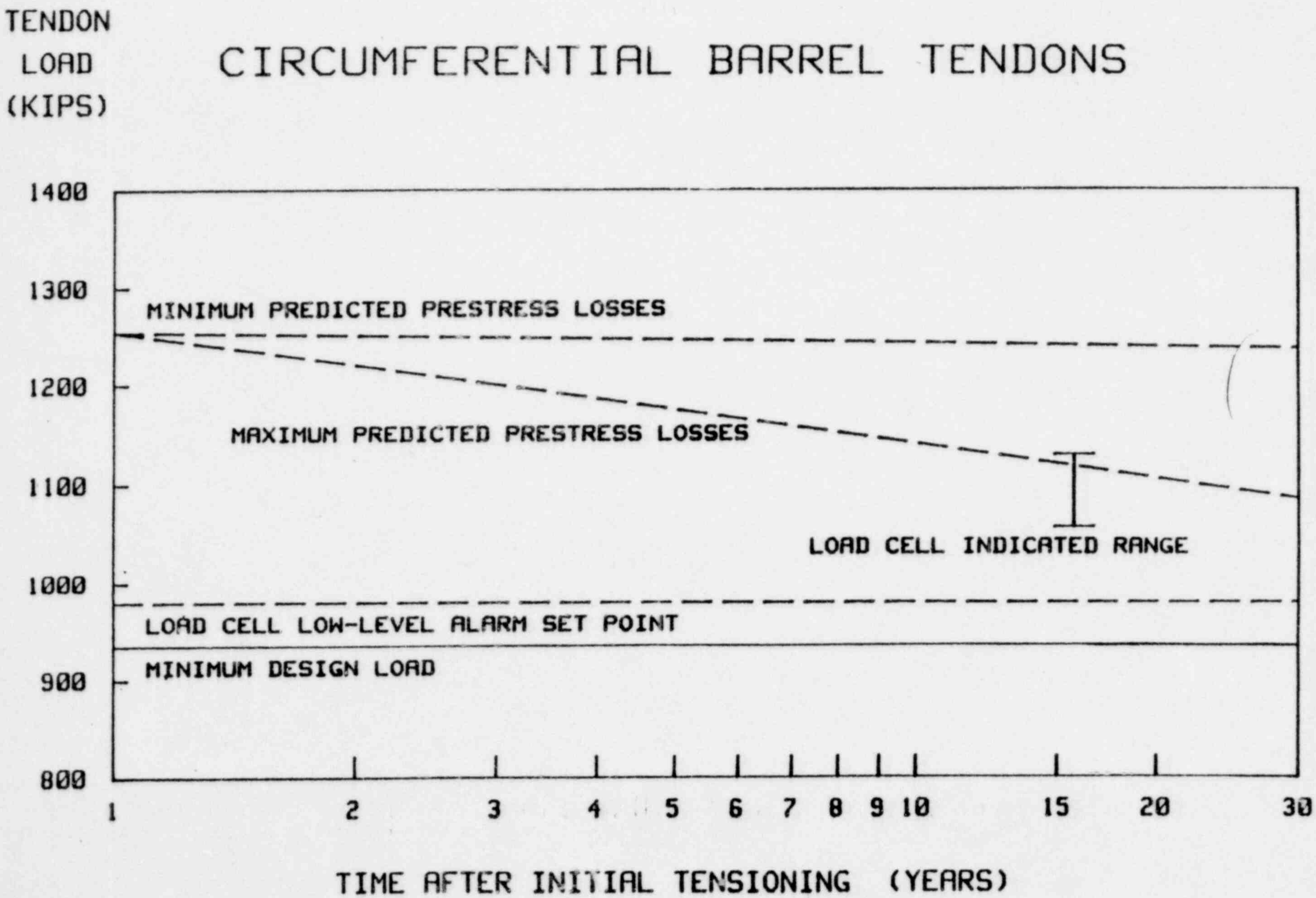
TENDON TYPE	TOTAL NUMBER	PERCENT OF TOTAL LIFTOFF	PERCENT OF TOTAL VISUAL
LONGITUDINAL	90	82 %	99 %
BOTTOM CROSS HEAD	24	83 %	100 %
TOP CROSS HEAD	24	100 %	100 %
CIRCUMFERENTIAL	310	49 %	55 %

LONGITUDINAL TENDONS




TENDON LOAD (KIPS)
CROSS HEAD TENDONS
1500
1400
1300
1200
1100
1000
900
800
700
600
MINIMUM PREDICTED PRESTRESS LOSSES
MAXIMUM PREDICTED PRESTRESS LOSSES
LOAD CELL INDICATED RANGE
LOAD CELL LOW-LEVEL ALARM SET POINT
MINIMUM DESIGN LOAD
1
2
3
4
5
6
7
8
9
10
15
20
30
TIME AFTER INITIAL TENSIONING (YEARS)


TENDON
LOAD
(KIPS)
CIRCUMFERENTIAL HEAD TENDONS
1500
1400
1300
1200
1100
1000
900
800
700
600
MINIMUM PREDICTED PRESTRESS LOSSES
MAXIMUM PREDICTED PRESTRESS LOSSES
LOAD CELL INDICATED RANGE
LOAD CELL LOW-LEVEL ALARM SET POINT
MINIMUM DESIGN LOAD
1
2
3
4
5
6
7
8
9
10
15
20
30
TIME AFTER INITIAL TENSIONING (YEARS)


TENDON LOAD (KIPS)
CIRCUMFERENTIAL BARREL TENDONS
1400
1300
1200
1100
1000
900
800
MINIMUM PREDICTED PRESTRESS LOSSES
MAXIMUM PREDICTED PRESTRESS LOSSES
LOAD CELL INDICATED RANGE
LOAD CELL LOW-LEVEL ALARM SET POINT
MINIMUM DESIGN LOAD
1
2
3
4
5
6
7
8
9
10
15
20
30
TIME AFTER INITIAL TENSIONING (YEARS)

REMEDIAL MEASURES AND PLANNED ACTIVITIES

- NITROGEN BLANKET / PURGE
- BULK SYNTHETIC OIL AND GREASE
- SPLIT SHIM LOAD CELL
- TENDON REPLACEMENT

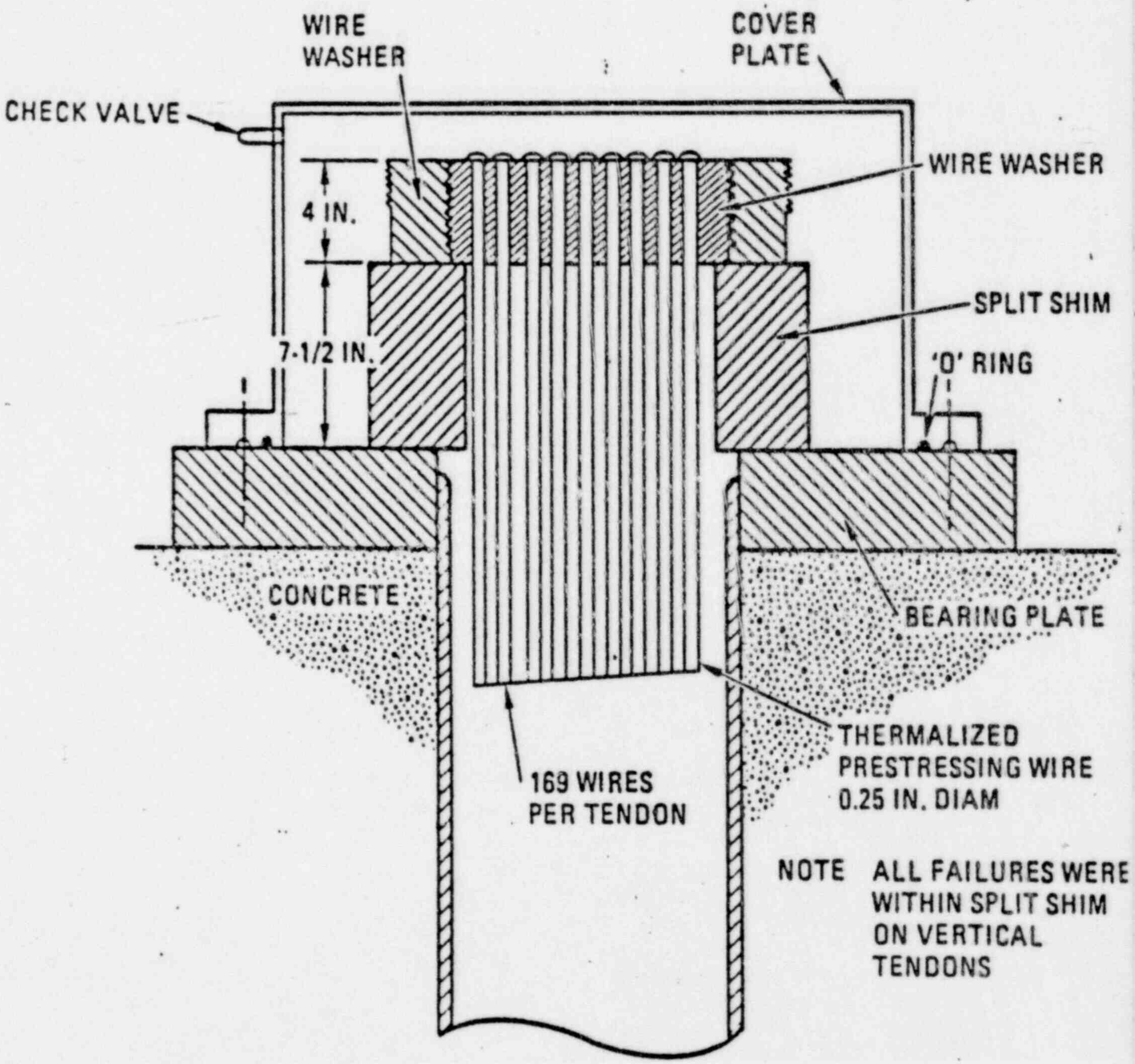


Fig. 3. Sketch of top head vertical tendon assembly.

EQUIPMENT QUALIFICATIONS

EQ AT FORT ST. VRAIN

* PSC IS CONTINUING TO DEVELOP A PROGRAM TO MEET THE REQUIREMENTS OF 10CFR50.49

* A CONTROLLED MASTER EQUIPMENT LIST HAS BEEN GENERATED IN ACCORDANCE WITH b1, b2, and b3 OF THE REGULATION

* FORT ST. VRAIN IS A DOR GUIDELINE PLANT AND EQUIPMENT QUALIFICATION BINDERS ARE BEING PREPARED

* THE QUALIFICATION BINDERS ADDRESS:

  - TEMPERATURE & PRESSURE
  - HUMIDITY
  - CHEMICAL EFFECTS
  - RADIATION
  - AGING
  - SUBMERGENCE
  - SYNERGISTIC EFFECTS
  - MARGIN

EQ AT FORT ST. VRAIN

STEAM LINE RUPTURE DETECTION AND ISLATION SYSTEM (SLRDIS)

PURPOSE

* Provide Continuous Monitoring of Area Temperatures in both Reactor & Turbine Buildings

* Miniminze Building Environmental Conditions Following Steam Line Rupture to:

  - Protect Functional Integrity of EQ Shutdown Equipment
  - Allow use of Industry Qualified Equipment
  - Enhance Re-entry into Plant Areas

SYSTEM SCOPE

* Temperature Sensors
* Microprocessor Logic Cabinet
* Interface with PPS for:
  - Circulator Trip
    (1) Four Circulator Trip
    (2) Two Loop Trouble
    (3) Reactor Scram
  - Valve Closure

EQ AT FORT ST. VRAIN

SLRDIS DESIGN BASES/FEATURES

* MEETS SINGLE FAILURE CRITERIA FOR PROTECTION SYSTEMS
* MEETS ENVIRONMENTAL QUALIFICATION REQUIREMENTS
* MEETS SEISMIC QUALIFICATION REQUIREMENTS
* UTILIZES TWO PANEL CONCEPT TO REDUCE IMPACT OF A SPURIOUS TRIP
* 2/4 LOGIC IN SENSING CIRCUITS
* REDUNDANT MICROPROCESSORS, LOGIC AND VALVE ACTUATION
* CAPABLE TO FUNCTION WITHOUT OFFSITE POWER
* ALARMS AT 135 DEGREES F (ANALYSIS VALUE)
* TRIPS AT 55 DEGREES F/MINUTE (ANALYSIS VALUE)

EQ AT FORT ST. VRAIN

TEMPERATURE PROFILES

* QUALIFICATION PROFILES REPRESENT A SPECTRUM OF BREAK SIZES

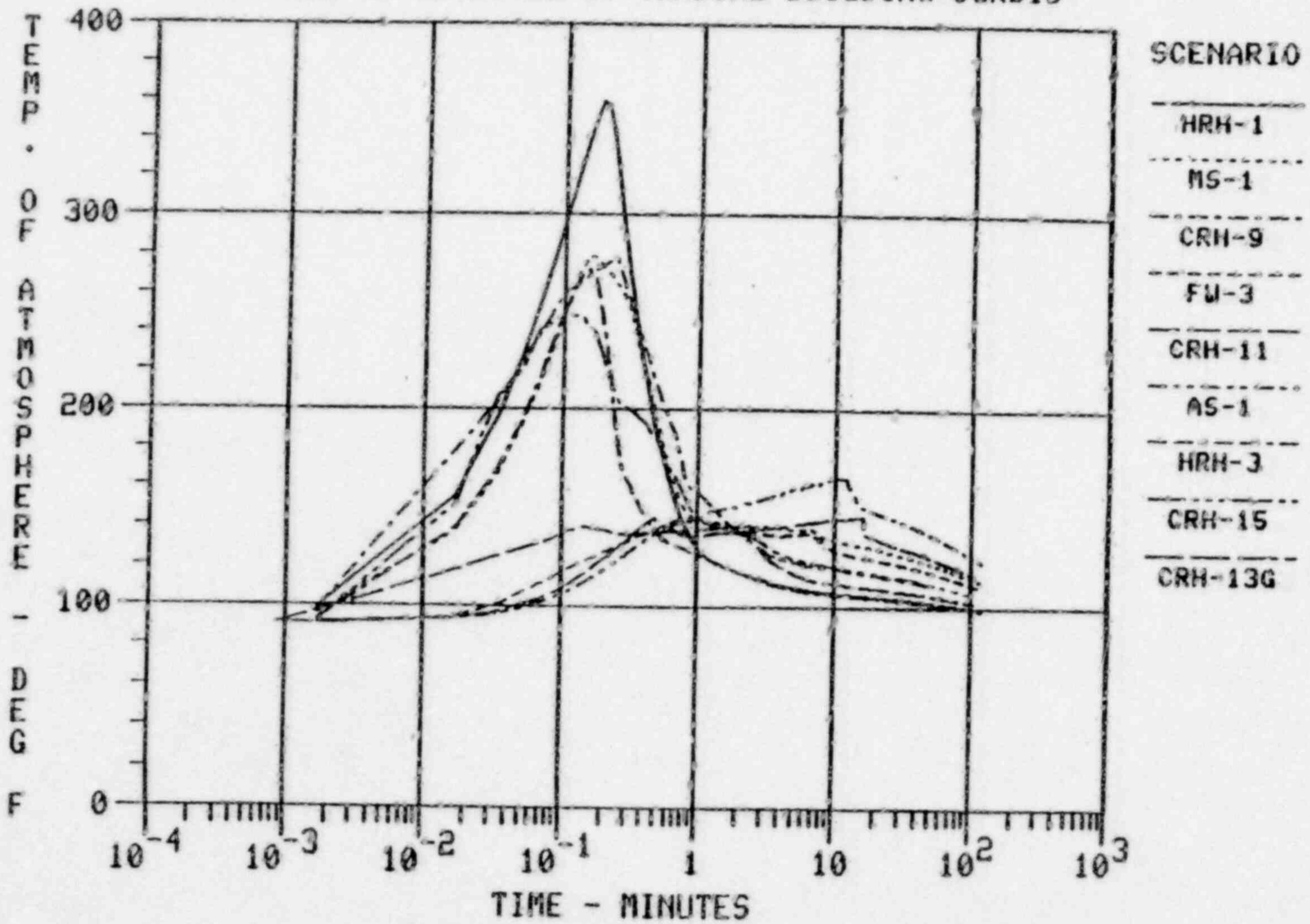
* LARGER BREAKS ARE AUTOMATICALLY TERMINATED BY SLRDIS RESULTING IN PEAK TEMPERATURES OF:

  360 DEGREES F - TURBINE BUILDING

  371 DEGREES F - REACTOR BUILDING

* SMALLER BREAKS REQUIRE OPERATOR ACTION TO TERMINATE WITH THE WORST CASE RESULTING IN A TEMPERATURE OF APPROXIMATELY 134 DEGREES F 1 HOUR AFTER TERMINATION

COMPOSITE SUMMARY OF LARGE AND SMALL LEAKS
ALARMED OR DETECTED BY TURBINE BUILDING SLRDIS



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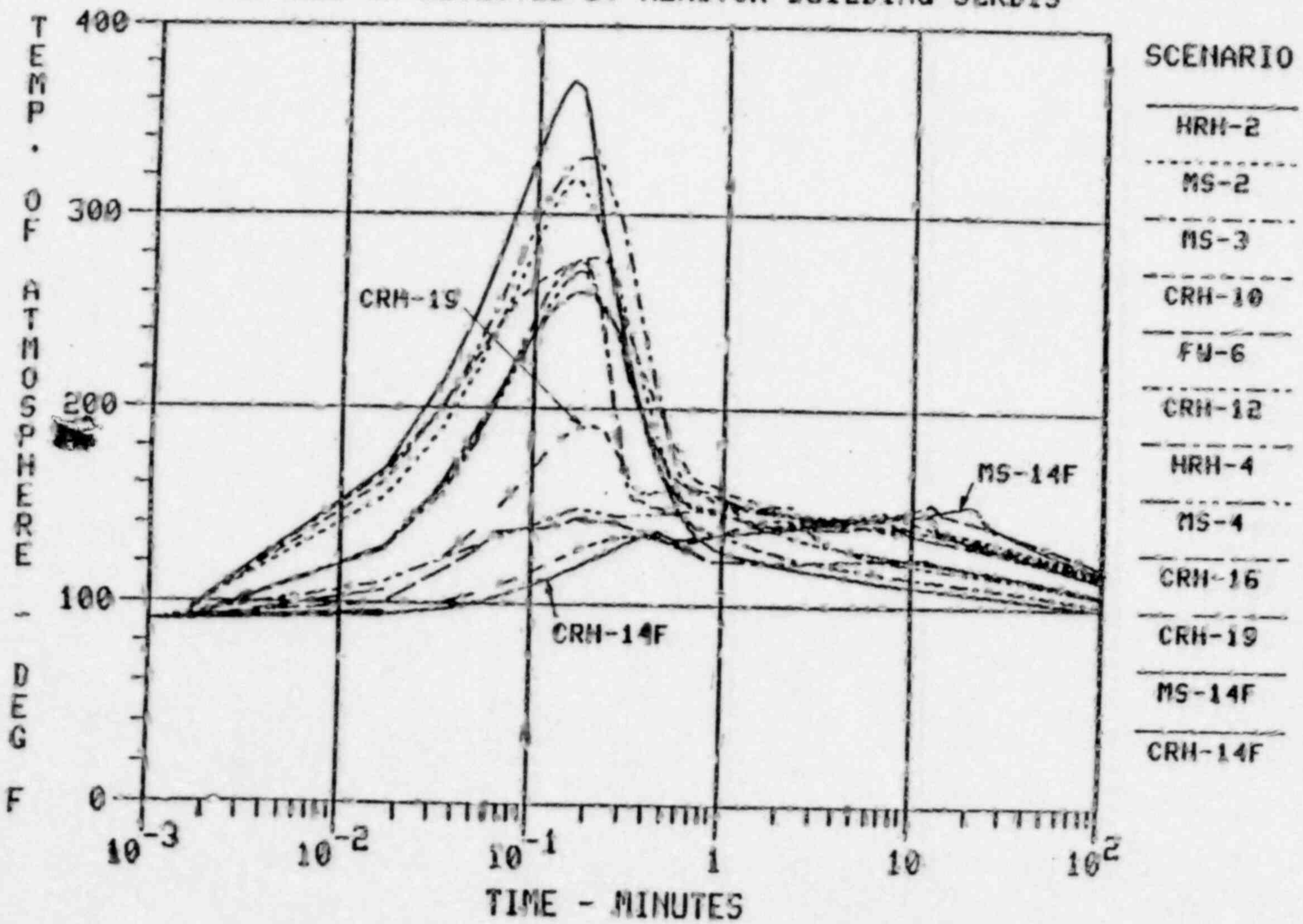
COMPOSITE SUMMARY OF LARGE AND SMALL LEAKS
ALARMED OR DETECTED BY REACTOR BUILDING SLRDIS



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EQ AT FORT ST. VRAIN

EQUIPMENT REPLACEMENTS

ITEM	#BEING REPLACED
SOLENOID VALVES	350
TRANSMITTERS	50
THERMOCOUPLES	50
MOTORS	12

OTHER CONSTRUCTION IMPACT

* RAYCHEM SPLICES
* MOISTURE PROTECTION

OTHER ACTIVITIES

* DEVELOPMENT OF ONGOING PROGRAM
* PROCEDURE REVISIONS
* TRAINING

EQ AT FORT ST. VRAIN

CURRENT PLANS

* RISE TO 35% POWER AND RUN UNTIL MAY 31, 1986

* PERFORM EQ CONSTRUCTION

* REQUEST COMMISSION APPROVAL TO OPERATE AT 35% POWER FOLLOWING EQ CONSTRUCTION WORK WHILE NRC PROGRAM REVIEWS AND SLRDIS TECH SPEC APPROVALS ARE TAKING PLACE

* THIS WILL ALLOW FSV TO OPERATE WHILE THE STAFF COMPLETES THEIR REVIEW OF THE FSV EQ PROGRAM AND SLRDIS TECH SPECS

STEAM GENERATOR TUBE INTEGRITY (NUREG-0844)

FSV STEAM GENERATOR (SG) TUBE LEAK SUMMARY

- TWO LEAK OCCURRENCES - NOVEMBER 1977 AND SEPTEMBER 1982

- SMALL SIZE - MUCH SMALLER THAN FSAR ANALYSIS

  - 2ND LEAK - EQUIVALENT TO 0.003" DIA. HOLE (APPROX. 5 GPD)

  - 1ST LEAK - LEAK LARGER THAN 2ND - NO FLOWRATE AVAILABLE

- BOTH LEAKS IN BOTTOM COIL OF SUPERHEATER 2 AT OR NEAR FLOATING TUBE SUPPORT PLATE A (MODULE B-1-1 IN 11/77 AND MODULE B-2-3 IN 9/82)

  - LEAK IN COIL BUT NOT NEAR 3D TUBE BEND OR WELD JOINT

- METALLURGICAL EXAMINATION RESULTS

  - SPECIMENS TAKEN FROM TUBING EXTERNAL TO SG MODULE

  - ALLOY 800 TUBING (MAIN STEAM SUBHEADER)

    FE-CR-NI OXIDE FILM ON ID WITH 0.008" AVG. THICKNESS
    NO EVIDENCE OF PITTING, CRACKING, OR EROSION/CORROSION
    FINE-GRAINED MICROSTRUCTURE TYPICAL OF ALLOY 800 GR I
    NO EVIDENCE OF WORK HARDENING
    GRAIN BOUNDARIES FREE OF CARBIDE PRECIPITATION

  - CARBON STEEL TUBING (FEEDWATER SUBHEADER)

    MAGNETITE CORROSION FILM ON ID WITH 0.010"-0.040" THICKNESS
    MICROSTRUCTURE TYPICAL FOR SA210 CARBON STEEL
    THICKNESS OF FILM SUGGESTS FUTURE NEED FOR CHEMICAL CLEANING

POTENTIAL SG TUBE LEAK CAUSES

° PSC AND GA EVALUATED MANY PHENOMENA TO DETERMINE THE CAUSES OF THE TWO LEAKS. POTENTIAL CAUSES CONSIDERED WERE:

- RESIDUAL STRESSES DUE TO COLD WORKING IN TUBE BENDS
- WELD JOINT DEFECTS
- VIBRATION FATIGUE STRESSES
- FEEDWATER CHEMISTRY
- GENERAL AND/OR CREVICE CORROSION
- WEAR AT SLEEVE/WEDGE ASSEMBLIES
- COLD SPRINGING DURING FABRICATION
- LOW CYCLE FATIGUE DUE TO OPERATIONAL CYCLES
- CRACK PROPAGATION FROM DEFECT DURING FABRICATION
- CARBURIZATION OF ALLOY 800
- LOSS OF TUBE SLEEVE/WEDGE ASSEMBLIES

° RESULTS OF EVALUATION WERE THAT NO PROBABLE CAUSE COULD BE DETERMINED AND CONCLUDED THAT LEAKS WERE RANDOM IN NATURE.

° SUBSEQUENT GA ANALYSIS (GA-907412) POSTULATES THAT SUFFICIENT FLOW INDUCED VIBRATION COULD DEVELOP TO CAUSE FAILURE IF THE TUBE SLEEVE/WEDGE ASSEMBLY WAS LOST. (I.E. THE TUBE IS THEN NOT SUPPORTED AT THE TUBE'S INTERSECTION WITH A SUPPORT PLATE WHEN THE PLANT IS ABOVE 70% POWER ALLOWING THE TUBE TO VIBRATE AND IMPACT ON THE TUBE SUPPORT PLATE).

FSV LICENSE AMENDMENT NO. 45 SUMMARY

° FOLLOWING 2ND TUBE LEAK, PSC PROPOSED TECH SPEC CHANGE TO PROVIDE A SURVEILLANCE PROGRAM FOR MONITORING SG TUBE INTEGRITY.

° AMENDMENT 45, LICENSE DPR 34 WAS APPROVED IN NOVEMBER 1984

- TECH SPEC SR 5.3.12 CONTAINS SURVEILLANCE PROGRAM
- EACH NEW TUBE LEAK TO BE EVALUATED TO DETERMINE LEAK SIZE, LOCATION, AND POTENTIAL CAUSE
- METALLURGICAL SPECIMENS FROM ASSOCIATED SUBHEADERS TO BE EVALUATED AND COMPARED WITH SPECIMENS FROM PREVIOUS TUBE LEAKS
- NRC TO BE NOTIFIED OF THE PSC FINDINGS AND ANY TREND IN TUBE DEGRADATION

° PSC COMMITTED TO REVISE FEEDWATER CHEMISTRY PROGRAM TO INCORPORATE SGOG GUIDELINES

- PSC "CHEMISTRY SPECIFICATIONS SECONDARY COOLANT SYSTEM-SYSTEM 31 PROCEDURE (WCP-302)" AND "CHEMISTRY CONTROL PROCEDURE (WCP-300)", WHICH WERE ISSUED ON 11/1/85, COMPLETED THIS COMMITMENT.

FSV STEAM GENERATOR DIFFERENCES

RESPONSE TO NUREG 0844 RECOMMENDATIONS MUST CONSIDER SIGNIFICANT DIFFERENCES BETWEEN THE FSV STEAM GENERATOR (SG) MODULES AND THE TYPICAL PWR SG. THESE DIFFERENCES ARE:

* MODULES ARE INSTALLED INSIDE THE PCRV RATHER THAN AS SEPARATE UNITS IN THE REACTOR BUILDING AS FOR A PWR SG.

* MODULE DESIGN AND LOCATIONS INSIDE THE PCRV HAS NO PROVISIONS FOR IN-SITU INSPECTIONS AS FOR A PWR SG.

* AS AN ALTERNATIVE TO AN IN-SITU INSPECTION OF A SG MODULE, REMOVAL OF A MODULE FOR INSPECTION WOULD RESULT IN SUBSTANTIAL RADIATION EXPOSURE TO PERSONNEL, INVOLVE AN EXTENDED PLANT OUTAGE AND BE PROHIBITIVELY EXPENSIVE.

* THE MOST LIKELY TUBE LEAK WOULD BE FROM THE SECONDARY TO PRIMARY RATHER THAN VICE VERSA AS IN A PWR SG.

* FSV SG TUBE LEAKS ARE LESS LIKELY THAN IN A PWR SG BECAUSE MANY PWR TUBES ARE WELDED AT TUBE SHEETS, AND THE FSV TUBES HAVE RELATIVELY THICK WALLS (0.140" TO 0.225" THK FOR THEIR TUBE DIAMETERS OF 1.000" TO 1.250").

* FEEDWATER IS INSIDE THE TUBES (RATHER THAN OUTSIDE AS FOR A PWR SG) WHERE THERE ARE NO OBSTRUCTIONS, STRUCTURES AND/OR CREVICES AS THERE ARE ON THE OUTSIDE OF THE TUBES OF A PWR SG WHERE THE FEEDWATER IS IN CONTACT WITH THE OUTSIDE SURFACES OF THE TUBES.

* DRY AND INERT HELIUM GAS IS ON THE OUTSIDE SURFACES OF THE TUBES RATHER THAN FEEDWATER AS IN A PWR SG.

* THE ONCE THROUGH (FEEDWATER) DESIGN REQUIRES A STRICT WATER CHEMISTRY PROGRAM TO MINIMIZE DEPOSITS ON THE INSIDE SURFACES OF THE TUBES. SLUDGE BUILDUP CANNOT BE TOLERATED IN THE FSV STEAM GENERATORS AS IN A PWR SG.

PSC RESPONSES TO NUREG 0844 RECOMMENDATIONS

THE CONCERNS FOR STEAM GENERATOR (SG) TUBE INTEGRITY IN AN PWR SG EXPRESSED IN NUREG 0844 HAVE BEEN ADDRESSED BY PSC AS FOLLOWS:

* THE STAFF RECOMMENDED ACTION TO INSPECT THE SECONDARY SIDE OF THE SG FOR LOOSE PARTS AND FOREIGN OBJECTS AND EXTERNAL DAMAGE IS IMPRACTICAL FOR FSV BECAUSE:

  - THIS IS THE INTERNAL SIDE OF THE TUBES WHERE THE SG DESIGN PRECLUDES THE LIKELIHOOD OF FOREIGN OBJECTS OR LOOSE PARTS.

  - INACCESSIBILITY OF THE SG TUBE BUNDLE ALSO PRECLUDES INTRODUCTION OF FOREIGN OBJECTS ON THE OUTSIDE SURFACES OF THE TUBES.

* THE STAFF RECOMMENDED ACTION TO PROVIDE QA/QC PROCEDURES FOR ACCOUNTABILITY OF FOREIGN OBJECTS THAT MIGHT BE LEFT INSIDE THE SG DURING AN INSPECTION OF THE TUBE OUTSIDE SURFACES IS APPROPRIATELY IMPLEMENTED BY EXISTING SG MAINTENANCE AND REPAIR PROCEDURES. HOWEVER, FSV PROCEDURES DO NOT GIVE DETAILED TREATMENT TO PHYSICALLY IMPOSSIBLE SITUATIONS AT FSV.

* THE STAFF RECOMMENDED ACTION TO INSPECT THE ENTIRE LENGTH OF THE TUBING O.D. FOR DEGRADATION IS CONSIDERED TO BE INAPPROPRIATE DUE TO ITS INACCESSIBILITY.

* THE STAFF RECOMMENDED ACTION TO LIMIT INSERVICE INSPECTION INTERVALS TO 72 MONTHS OR LESS IS INCONSISTENT WITH THE SURVEILLANCE INTERVAL APPROVED BY AMENDMENT 45, LICENSE DPR-34. FSV TECH SPEC SR 5.3.12 REQUIRES THE SURVEILLANCE PROGRAM TO BE PERFORMED FOLLOWING EACH NEW TUBE LEAK.

PSC RESPONSES TO NUREG 0844 RECOMMENDATIONS

* THE STAFF RECOMMENDED ACTION TO INCORPORATE THE SECONDARY WATER CHEMISTRY GUIDELINES OF SGOG SPECIAL REPORT EPRI-NP-2704, "PWR SECONDARY WATER CHEMISTRY GUIDELINES" HAS BEEN IMPLEMENTED AT FSV BY ISSUE OF PROCEDURES WCP-300 AND WCP-302 IN NOVEMBER 1985.

* THE STAFF RECOMMENDED ACTION TO IMPLEMENT A CONDENSER INSERVICE INSPECTION PROGRAM TO MINIMIZE CONDENSER TUBE LEAKS AND ASSIST PREVENTIVE MAINTENANCE PROGRAMS IS CONSIDERED INAPPROPRIATE FOR FSV BECAUSE CONDENSER INTEGRITY IS ASSURED BY:

  - THE POLISHING DEMINERALIZER AND DEAERATOR WHICH REMOVES ANY IMPURITIES THAT COULD LEAK INTO THE CONDENSATE BEFORE IT IS RETURNED TO THE SG.

  - WATER CHEMISTRY WHICH IS MONITORED BY CONTINUOUS ANALYTICAL RECORDING EQUIPMENT AND GRAB SAMPLE ANALYSES ON A DAILY BASIS. BREAK THROUGH OF THIS POLISHING DEMINERALIZER WOULD BE QUICKLY DETECTED.

  - THE WATER CHEMISTRY CONTROL PROCEDURES WHICH MITIGATE THE DEPOSIT OF RESIDUE ON THE TUBES OF THE ONCE THROUGH FSV SG.

  - THE 304 SS TUBES WHICH HAVE ESSENTIALLY ELIMINATED CONDENSER TUBE LEAKS SINCE THEIR INSTALLATION IN LATE 1979.

  - PSC'S PRACTICE TO INSPECT THE MAIN CONDENSER'S CONDITION AT EVERY MAJOR OUTAGE.

PSC RESPONSES TO NUREG 0844 RECOMMENDATIONS

* THE STAFF RECOMMENDED ACTION TO ADOPT STANDARD TECHNICAL SPECIFICATIONS (STS) LIMITS FOR PRIMARY TO SECONDARY LEAKAGE RATES IS CONSIDERED TO BE INAPPROPRIATE BECAUSE:

  - THE MOST LIKELY LEAKAGE IN THE FSV SG IS FEEDWATER LEAKAGE INTO THE RCS. THIS HAS EXTREMELY LOW LEAKAGE LIMITS AT FSV TO PROTECT THE CORE FROM OXIDATION DUE TO THE MOISTURE INGRESS. THE ONLY SG TUBE LEAKS TO DATE HAVE BEEN OF THIS TYPE.

  - A REHEATER TUBE LEAK WILL ALLOW REACTOR COOLANT LEAKAGE INTO THE SECONDARY COOLANT SYSTEM. THESE LEAKS ARE ALARMED BY RADIATION MONITORS IN THE REHEAT STEAM PIPING. LARGE LEAKS ARE AUTOMATICALLY ISOLATED AND SMALL LEAKS ARE MANUALLY ISOLATED.

* THE STAFF RECOMMENDED ACTION TO ADOPT STS LIMITS AND SURVEILLANCE FOR IODINE ACTIVITY IS CONSIDERED INAPPROPRIATE FOR FSV BECAUSE:

  - FSV TECH SPECS LCO 4.2.8 ALREADY LIMIT ACTIVITY IN THE REACTOR COOLANT SO AS TO LIMIT RELEASES TO THE ATMOSPHERE WELL BELOW 10 CFR 100 GUIDELINES FOR DESIGN BASIS ACCIDENTS WHICH ARE MUCH LARGER THAN THAT WHICH WOULD RESULT FROM A SG REHEATER TUBE LEAK.

* THE STAFF RECOMMENDED ACTION TO MODIFY THE CONTROL LOGIC FOR SAFETY INJECTION PUMPS IS CONSIDERED TO BE INAPPROPRIATE FOR FSV BECAUSE FSV HAS NO SUCH PUMPS OR ANY EQUIPMENT THAT PERFORMS A SIMILAR FUNCTION.

MASONRY BLOCK WALLS

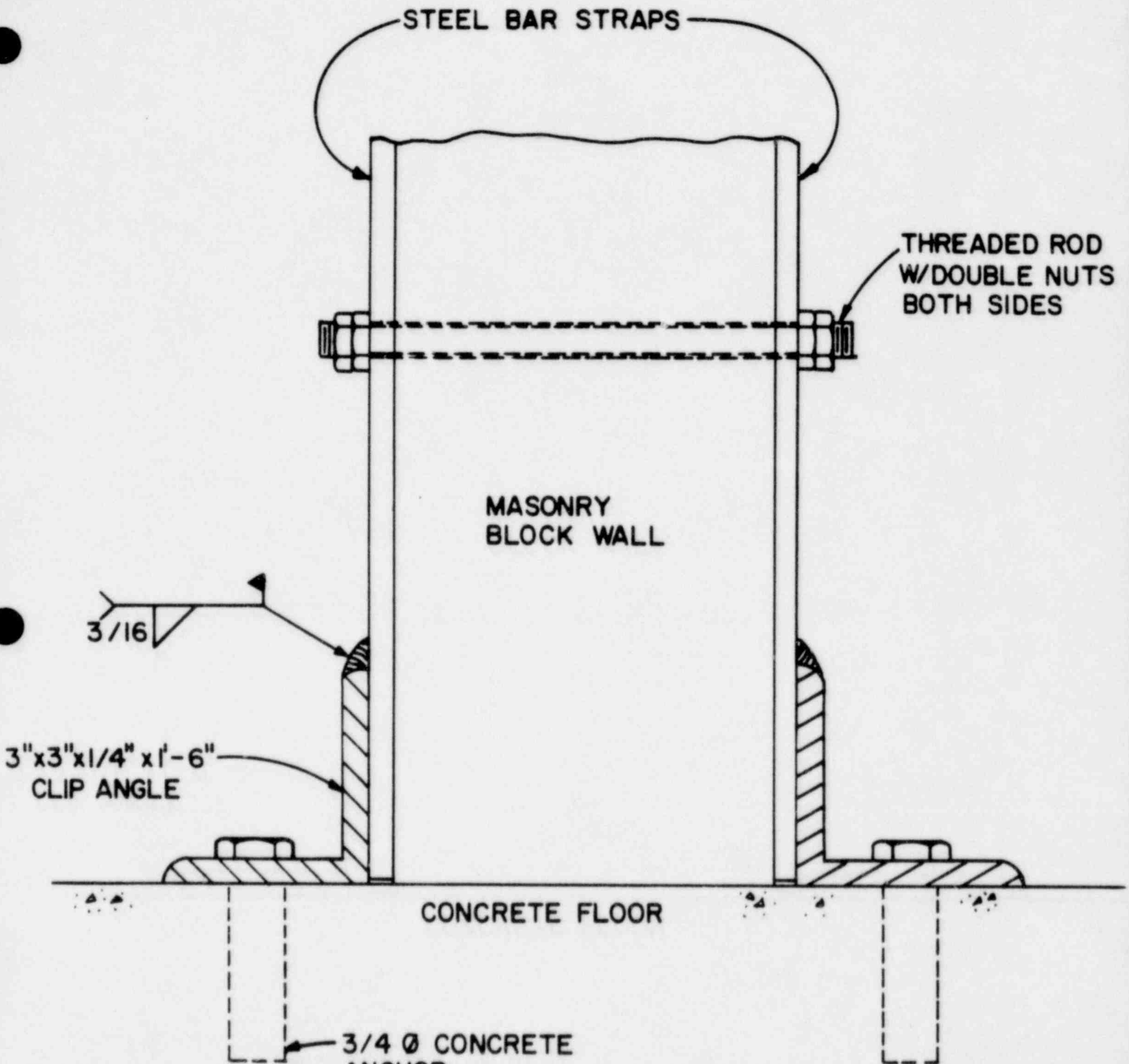
MASONRY BLOCK WALLS

* IE BULLETIN 80-11 REQUESTED AN EVALUATION OF THE DESIGN ADEQUACY OF MASONRY BLOCK WALLS WHICH ARE IN PROXIMITY OF, OR HAVE ATTACHMENTS TO SAFETY RELATED PIPING OR EQUIPMENT

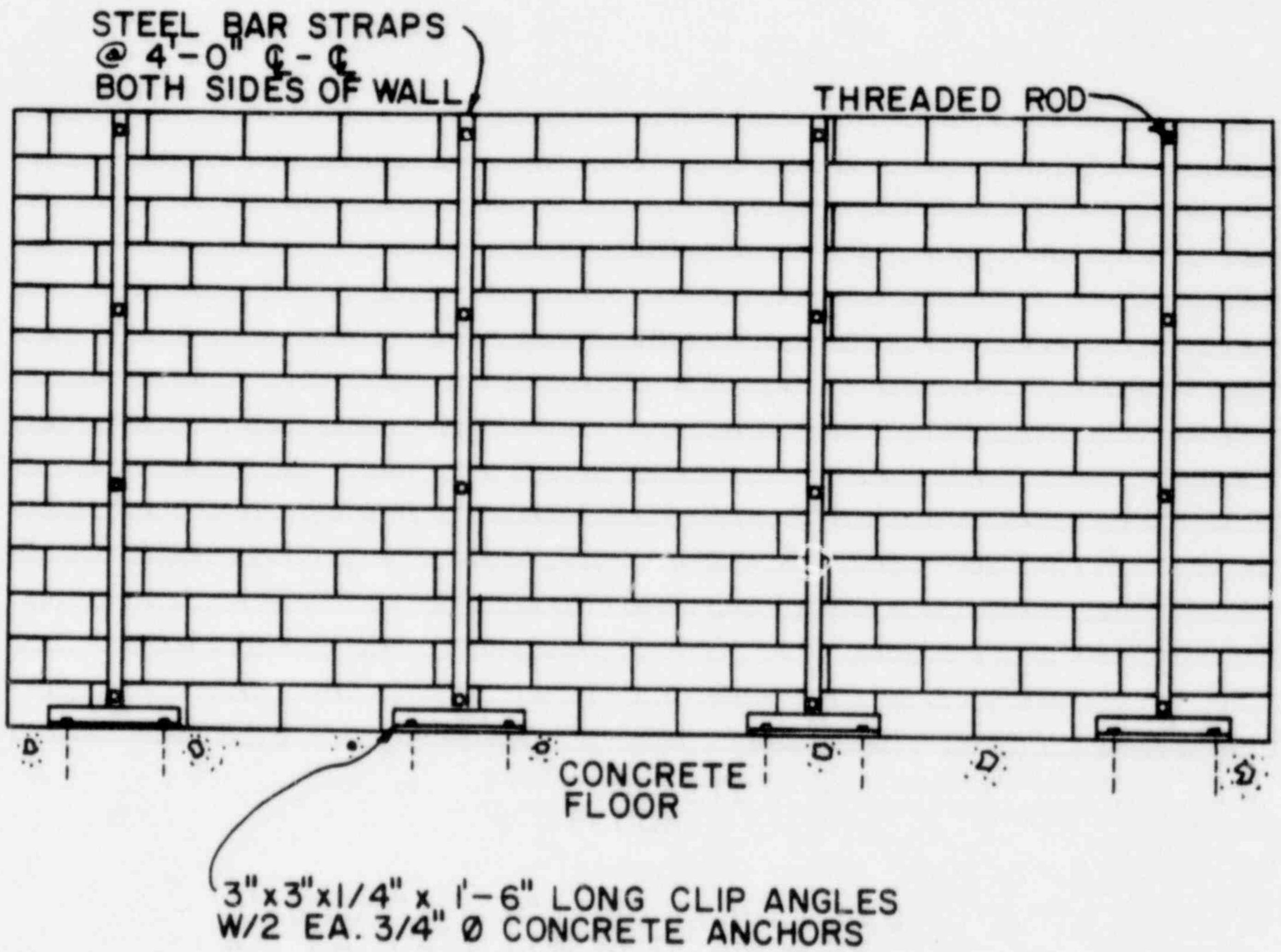
* ORIGINAL FSV DESIGN FOR MASONRY BLOCK WALLS
  - NON REINFORCED
  - NON LOAD BEARING
  - NO SEISMIC CONSIDERATIONS

* EVALUATIONS RESULTED IN IMPROVEMENTS
  - ADDED BOLTED STEEL BAR STRAPS TO EXTERIOR OF WALLS TO INSURE INTEGRITY DURING SEISMIC EVENT

* STATUS
  - CONSTRUCTION COMPLETE EXCEPT FOR 3 SMALL PENETRATIONS INTO SPENT FUEL STORAGE AREA
  - PENDING COMPLETION OF SPENT FUEL SHIPPING THESE WALLS SHOULD BE UPGRADED IN JUNE 1986
  - PSC RECEIVED THE NRC STAFF SER ON JANUARY 15, 1986 INDICATING THAT PSC'S DESIGN MODIFICATIONS WERE ACCEPTABLE



SECTION THRU WALL



MASONRY BLOCK WALL
ELEVATION VIEW

HUMAN FACTORS RELATED TO OPERATIONS IN HOSTILE ENVIRONMENTS

ICE VESTS

Introduction

- Although EQ Program does not depend on access in harsh environment, PSC has concluded that access is possible in temperatures up to 180 degrees F using the cool suits.

Technical Advisor - Dr. Thomas Bernard, Westinghouse

- Worked 2 years under EPRI contract on Heat Stress Management

- Co-authored: EPRI NP 2868, "Personal Cooling in Nuclear Power Stations" and EPRI NP 4453, "Heat Stress Management Program for the Nuclear Power Industry".

- Supports 180 degrees F based upon theory that ice vest breathing apparatus and cotton clothing create a micro-environment to isolate individual from harsh temperatures.

Testing

- Laboratory tests documented in EPRI NP2868 demonstrate use of ice vests at 131 degrees F for over 100 minutes on the average

Industry Survey

- TMI has used ice vests in temperatures of 160 degrees F for 15-25 minutes

- Oyster Creek frequently uses in temperatures of 140 degrees F up to one hour

- Workers reported that these amounts of time were not limited by heat stress

PSC Use of Ice Vests

- Not required but provided

- Recognized safety program

- Breathing apparatus used for elevated temperatures

- Buddy system

- One member of team carries light source and radio for communication to outside

Equipment on Site

- 40 ice vests in two freezers located in Building 10 (mild environment)

- Over 60 breathing apparatus bottles on site, 30 dedicated to EQ Program and located in Building 10

FIRE PROTECTION ACTIONS (APPENDIX R)

FIRE PROTECTION ACTIONS (APPENDIX R)

INTRODUCTION

SUBMITTAL OF APPENDIX R EVALUATION

- REPORT NO. 1, APPENDIX R EVALUATION - SHUTDOWN MODEL 11/16/84 (P-84493)

- REPORT NO. 2, APPENDIX R EVALUATION - ELECTRICAL REVIEWS 12/17/84 (P-84526)

- REPORT NO. 3, APPENDIX R EVALUATION - FIRE PROTECTION REVIEWS 1/17/85 (P-85010)

- REPORT NO. 4, APPENDIX R EVALUATION - EXEMPTION AND MODIFICATIONS 4/01/85 (P-85113)

- REPORT NO. 5, FIRE HAZARDS ANALYSIS & EVALUATION OF BUILDING 10 TO BTP 9.5-1 APPENDIX A GUIDELINES 5/31/85 (P-85187)

EVALUATION RESULTS/STATUS

- EXEMPTION REQUESTS - WAITING FOR NRC APPROVAL

- MODIFICATIONS (TABLE 4-1 OF REPORT NO. 4)

  ° MOST SIGNIFICANT MODIFICATIONS: - Fire Detection
  - Emergency Lighting

  ° 13 OUT OF 29 ITEMS ARE COMPLETE

DETECTION SYSTEM

* Installation to be complete by June 1, 1986

* Extensive coverage in Reactor and Turbine Buildings

* Combination of photo electric area detectors and linear beam detectors

* Area detectors are individual units which use the light scattering theory

* Linear beam detectors have the transmitter and receiver separated by as much as approximately 150'

* Preliminary design has been discussed verbally with NRC Fire Protection Reviewer

EMERGENCY LIGHTING

- Preliminary design only; waiting for NRC approval of exemption request.
- In addition to battery powered units, FSV will rely on new AC lighting powered by the ACM diesel.
- Combination of florescent and incandescant fixtures.
- 2 circuits covering different sections of the plant.
- Circuits enter buildings at different locations.
- Circuits remain 30 feet apart.
- Breaker coordination such that only one circuit could fail given loss of any one light or any single fault.

FIRE PROTECTION ACTIONS (APPENDIX R)

RECENT CORRESPONDENCE

- RESPONSE TO 5 FIRE PROTECTION REVIEW QUESTIONS SUBMITTED 8/30/85 (P-85301)

- RESPONSE TO 16 SYSTEMS REVIEW QUESTIONS (DATED 11-1-85, G-85459) SUBMITTED 12-20-85 (P-85488)

FUTURE COMMITMENTS

- RESPONSE/CLARIFICATION TO 2/26/86 PHONE CALL SUBMITTED 3/14/86 (P-86209)

- COMMITMENTS:

  ° APRIL LETTER TO SUPPLY INFORMATION PSC UNDERSTANDS TO BE NECESSARY FOR SER (i.e., VALVE POSITION VERIFICATION APPROACH, DETAILS ON MANUAL ACTIONS AND TIMING)

  ° SUBMIT STEAM GENERATOR ANALYSIS

  ° DEVELOP FIRE PROTECTION PROGRAM PLAN

TABLE 4-1

SCHEDULE FOR PROPOSED MODIFICATIONS

Item	Description	Change Notice and Material On Site	Length of Required Plant Shutdown (Days)*	Completion Date
4.1	Fire Doors	Aug. 15, 1985	0	Nov. 15, 1985
4.2	Penetration Seals	June 1, 1985	0	July 15, 1985
4.3	Fire Damper	Aug. 1, 1985	0	Sept. 15, 1985
4.4	Emergency Lighting	6 months following NRC approval	0	12 mos. following NRC approval
4.5	Fire Detection	Sept. 1, 1985	0	Feb. 1, 1986
4.6	ACM Backfeed to Three-Room Complex	July 1, 1985	2	----
4.7	Ventilation Damper Air Bottle	June 1, 1985	0	Aug. 1, 1985
4.8	Portable Ventilation Fans	June 1, 1985	0	July 15, 1985
4.9	Portable Turbine Water Removal Pump	Oct. 15, 1985	14	----
4.10	Cable Re-Routes			
(a)	Reactor Plant Exhaust Fan	Dec. 1, 1985	14	----
(b)	Bearing Water Makeup	Nov. 15, 1985	14	----
(c)	Surge Tank Level Instrumentation	Nov. 1, 1985	14	----

TABLE 4-1
(continued)

Item	Description	Change Notice and Material On Site	Length of Required Plant Shutdown (Days)	Completion Date
4.10 (d)	Feedwater Flow Monitoring	Oct. 15, 1985	14	----
(e)	Feedwater Flow Associated Cables	Oct. 1, 1985	14	----
(f)	ACM fuel Oil Transfer Pump	Dec. 15, 1985	14	----
(g)	Helium Flow Inst. Cables	Dec. 30, 1985	14	----
(h)	Main Steam Temp. Indic.	Jan. 15, 1986	14	----
(i)	Bearing Water Pumps	Feb. 15, 1986	14	----
(j)	Emergency Water Booster Pump	Mar. 15, 1986	14	----
4.11	Valve Operability			
(a)	Disconnect Switches	Sept. 15, 1985	14	----
(b)	Valve Operator Air Bottles	June 1, 1985	14	----
(c)	Local Control Valve	June 1, 1985	14	----
(d)	Manual Bypass	July 1, 1985	14	----
(e)	Ladders	June 1, 1985	0	July 15, 1985
(f)	Valves Tagging	June 1, 1985	0	July 15, 1985

TABLE 4-1
(continued)

Item	Description	Change Notice and Material On Site	Length of Required Plant Shutdown (Days)	Completion Date
4.12	S.W. Return Pump	Jan. 1, 1986	14	----
4.13	ACM Diesel Tech. Specs	----	--	April 1, 1985 (draft to NRC)
4.14	Shutdown Procedures	----	--	Oct. 1, 1985
	Special Repair Procedures (including fire watch)	----	--	July 1, 1985 or by startup if after that date.

* Table 4-1 identifies numerous modifications requiring at least a 14-day scheduled plant shutdown for installation. PSC will make every effort to install as many as possible during each scheduled shutdown, but it should not be inferred that all modifications for which material is on-site will be installed during the first scheduled shutdown.

OTHERS (NOTES)

SUMMATION (NOTES)

APPENDIX I

DESCRIPTION, FORT ST. VRAIN

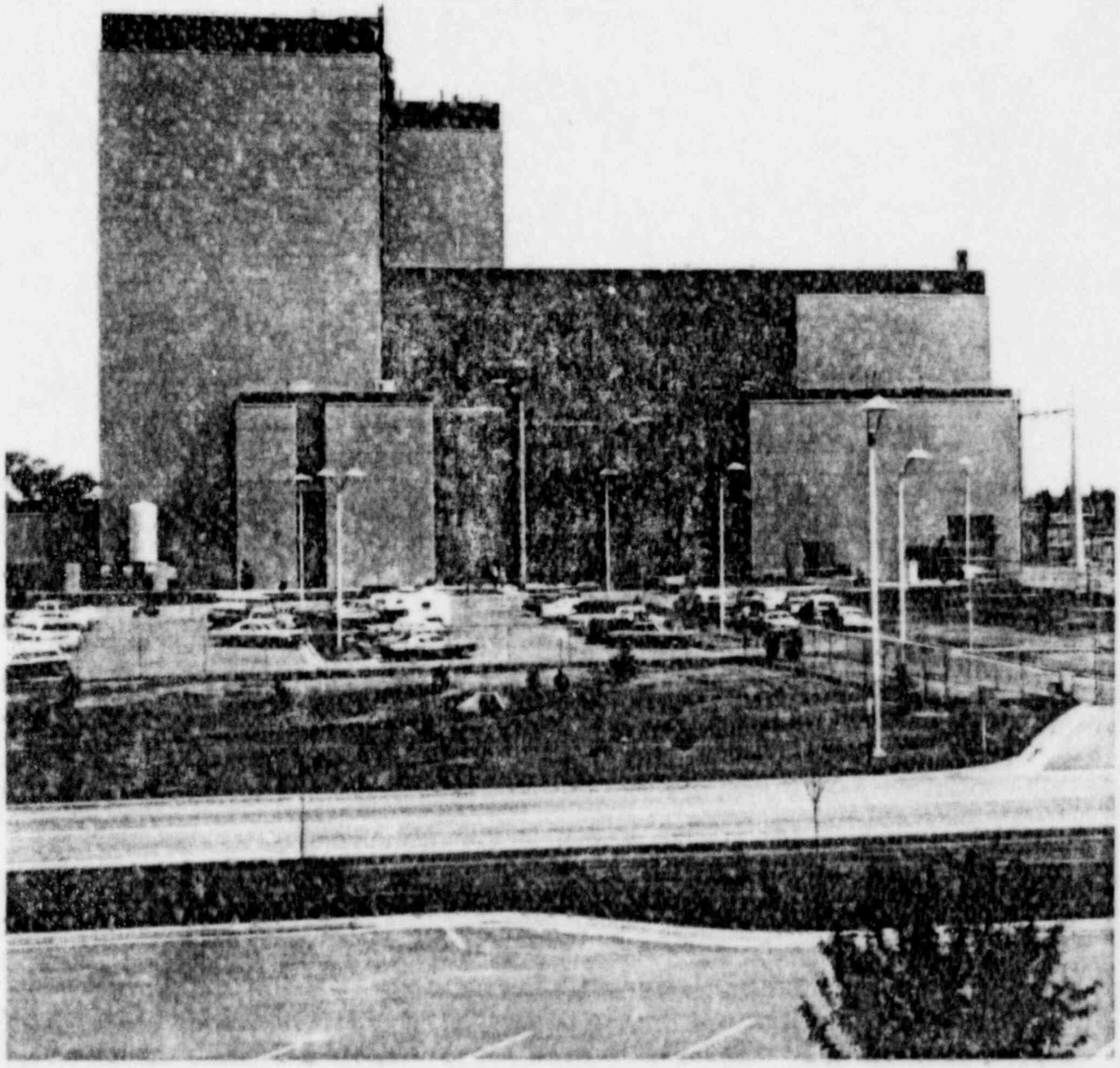


Figure 1.2-1 Fort St. Vrain Nuclear Generating Station

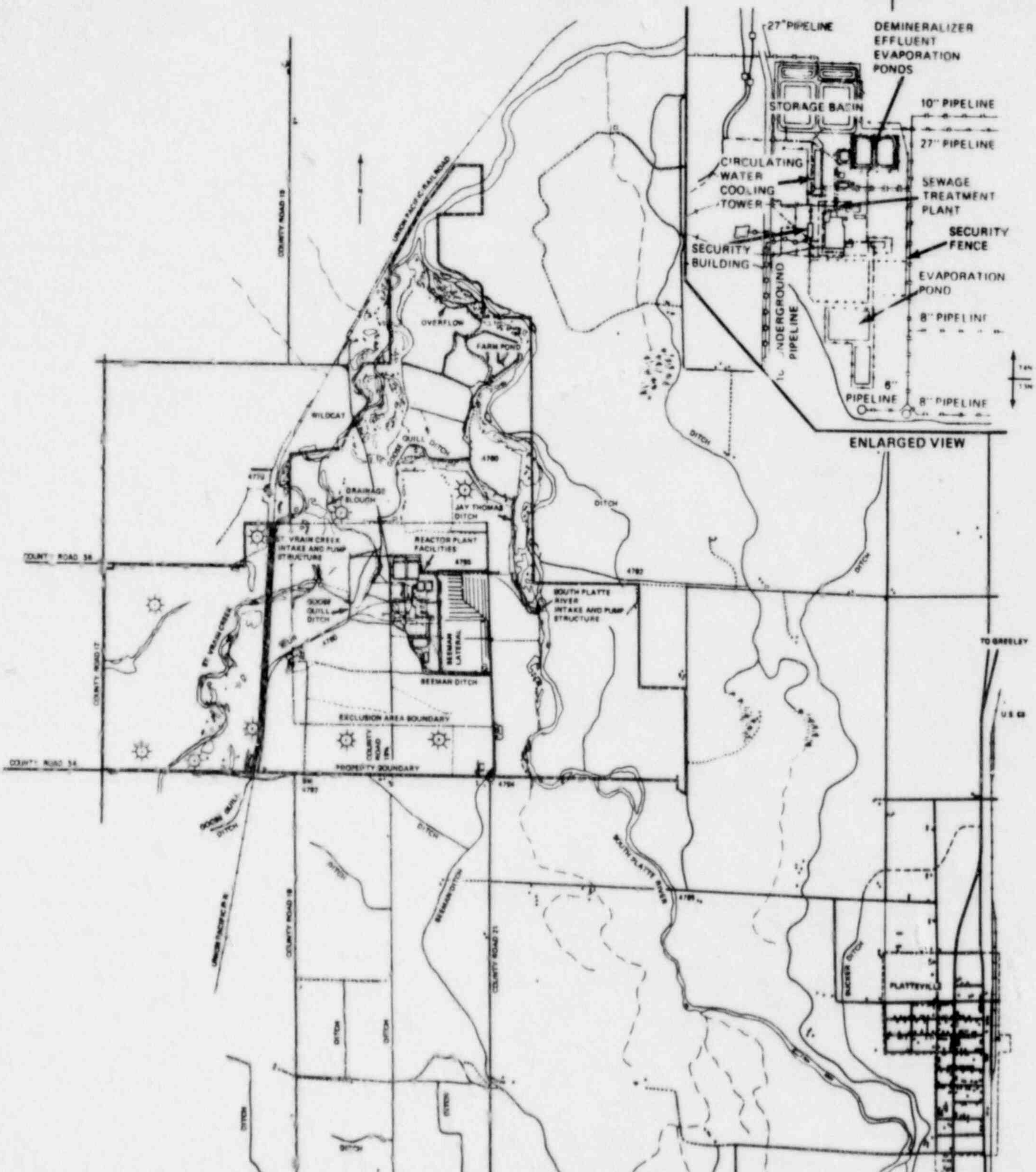


Figure 2.1-4 Site of Fort St. Vrain Nuclear Generating Station

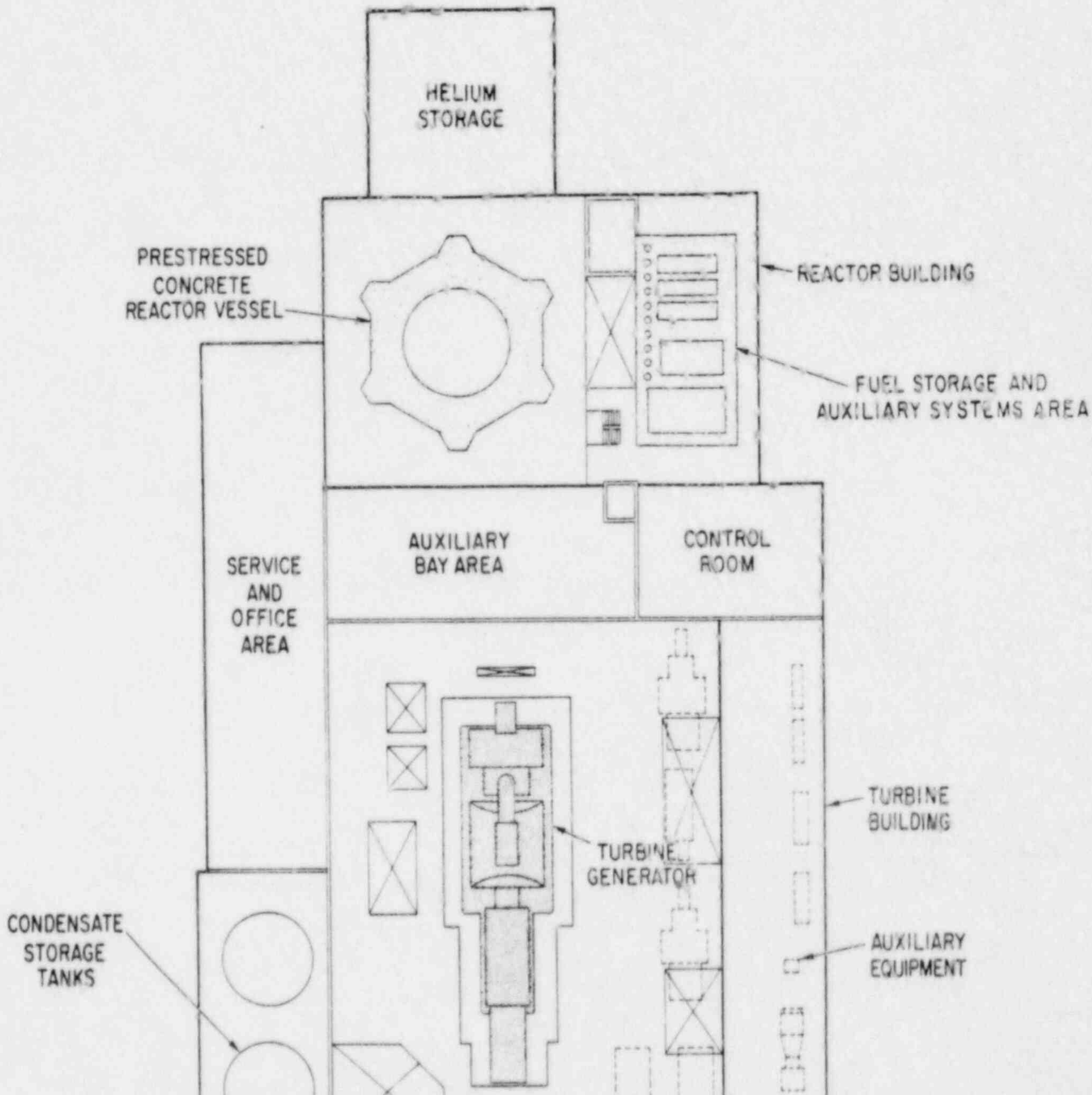


Figure 1.2-2 Plan View of Reactor Building and Turbine Building

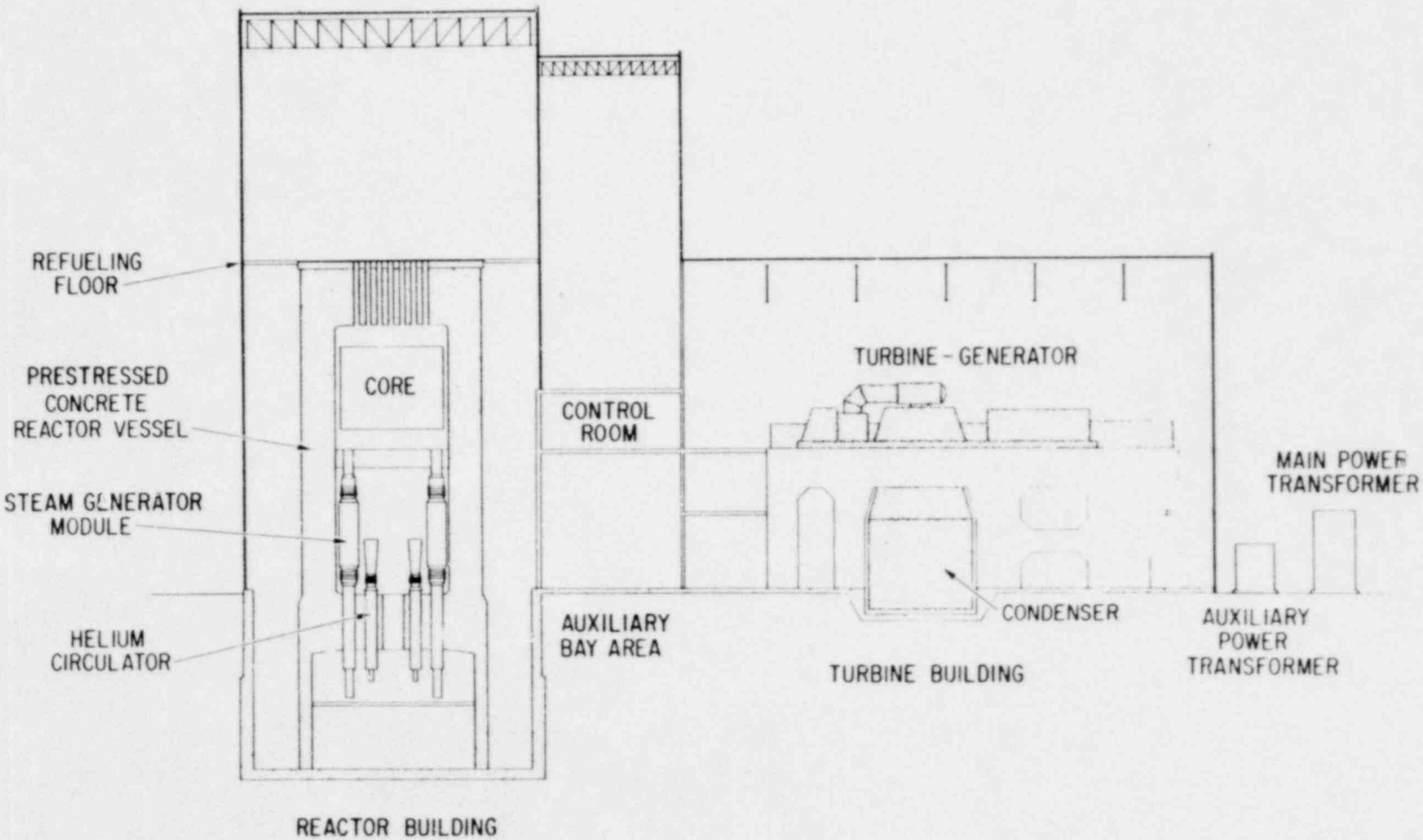


Figure 1.2-3 Section Through Reactor Building and Turbine Building

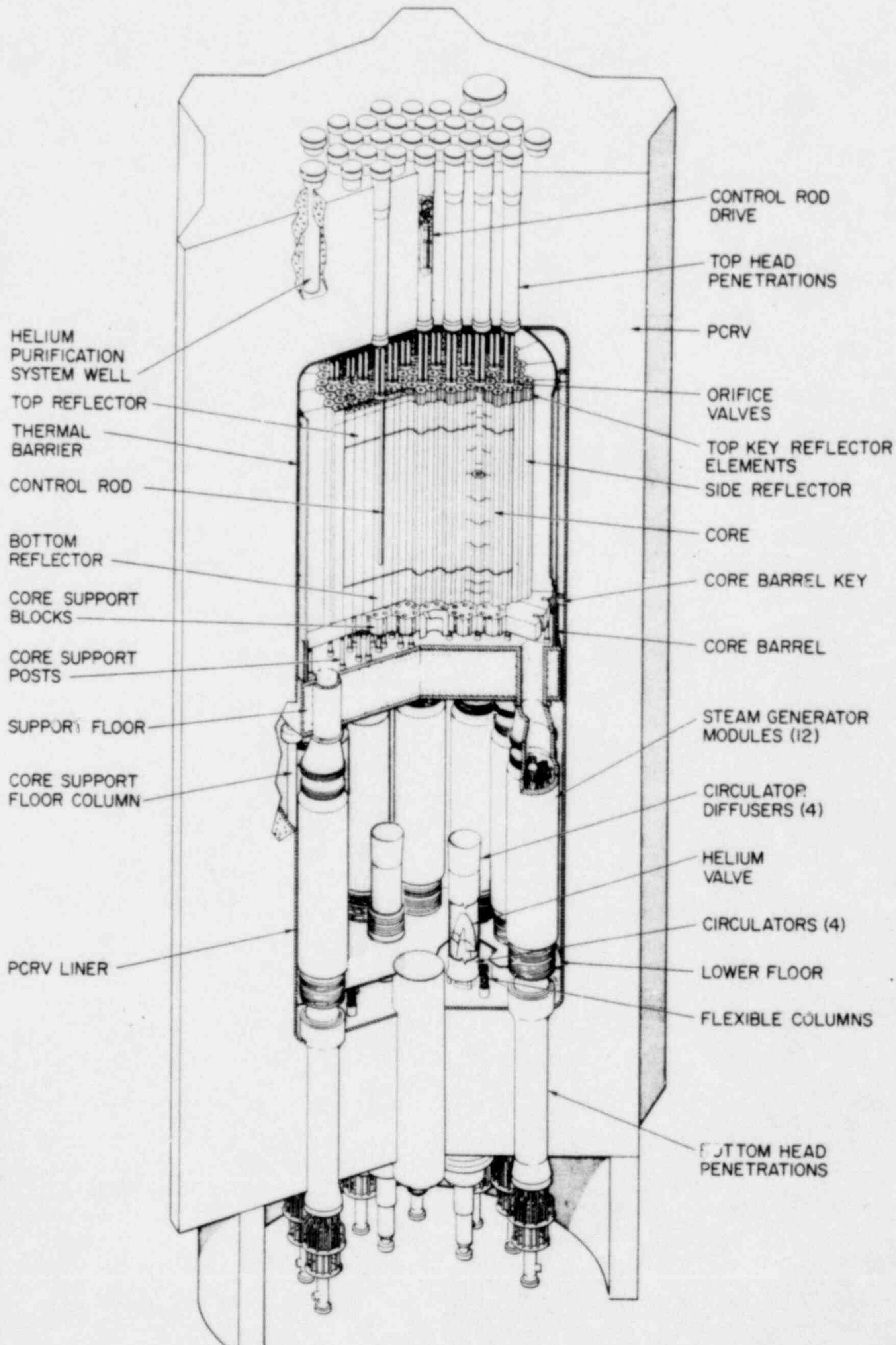


Figure 3.1-1 Reactor Arrangement

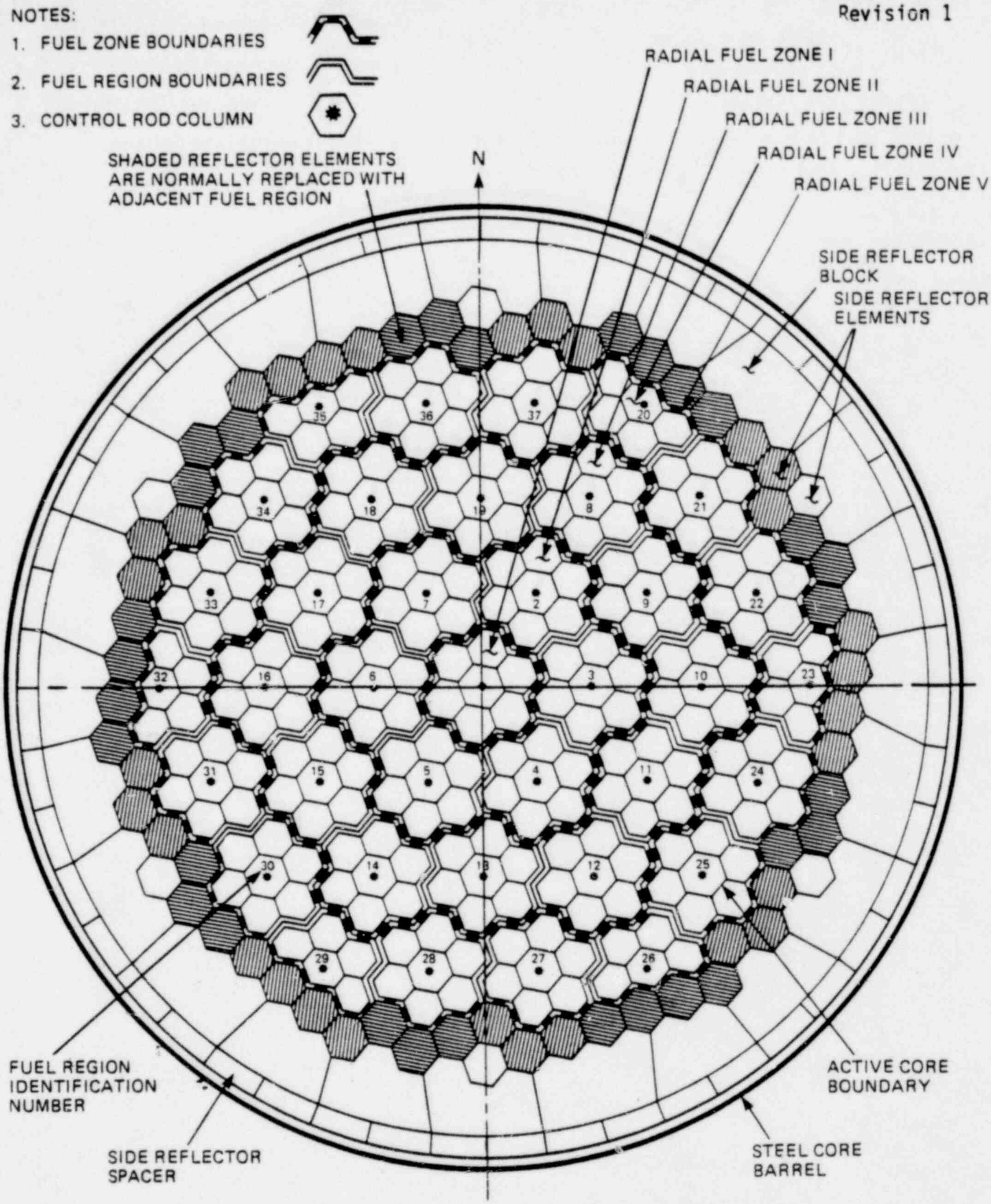


Figure 3.1-2 Core Plan View

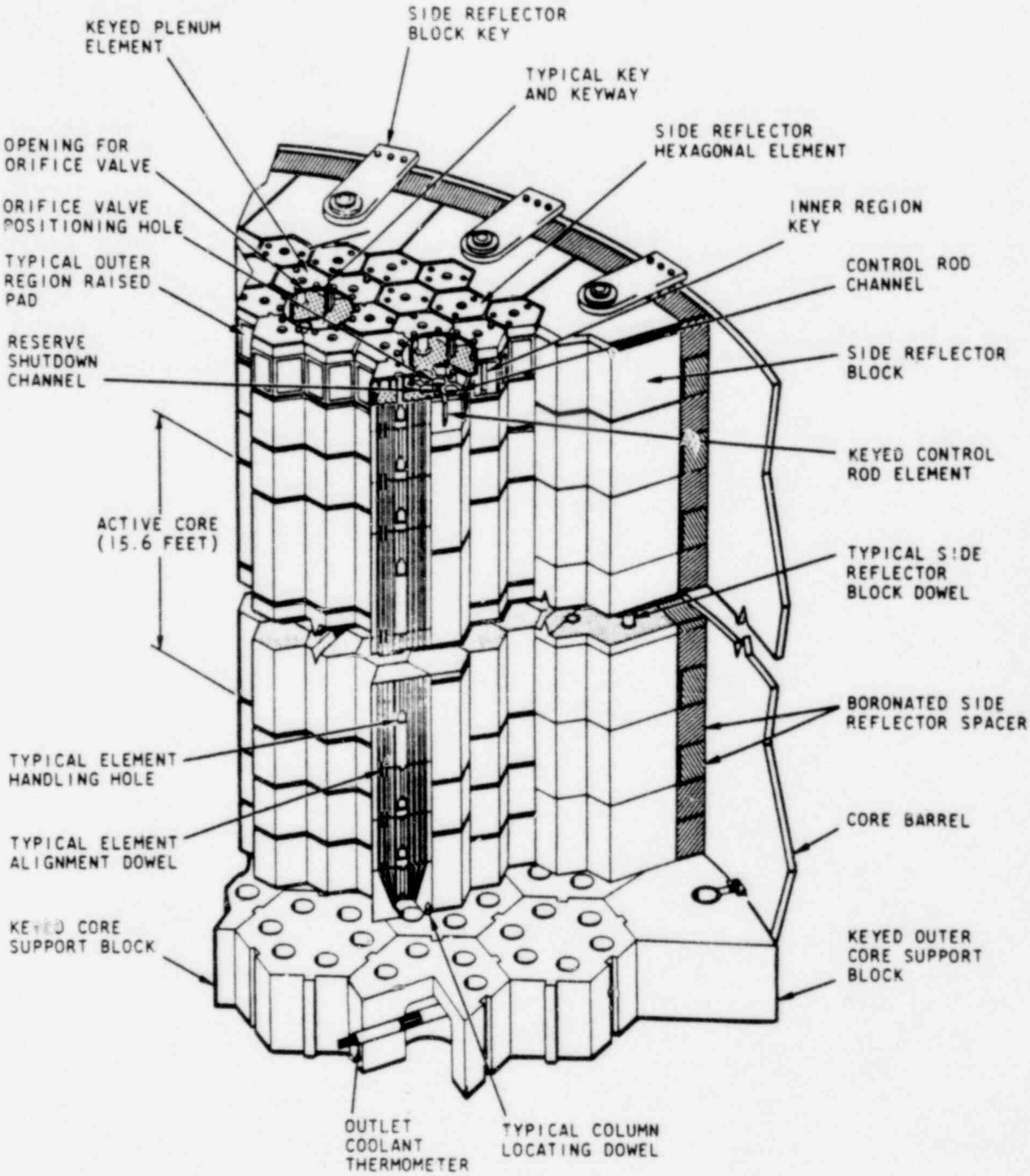


Figure 3.1-3 Core Arrangement, Elevation Section

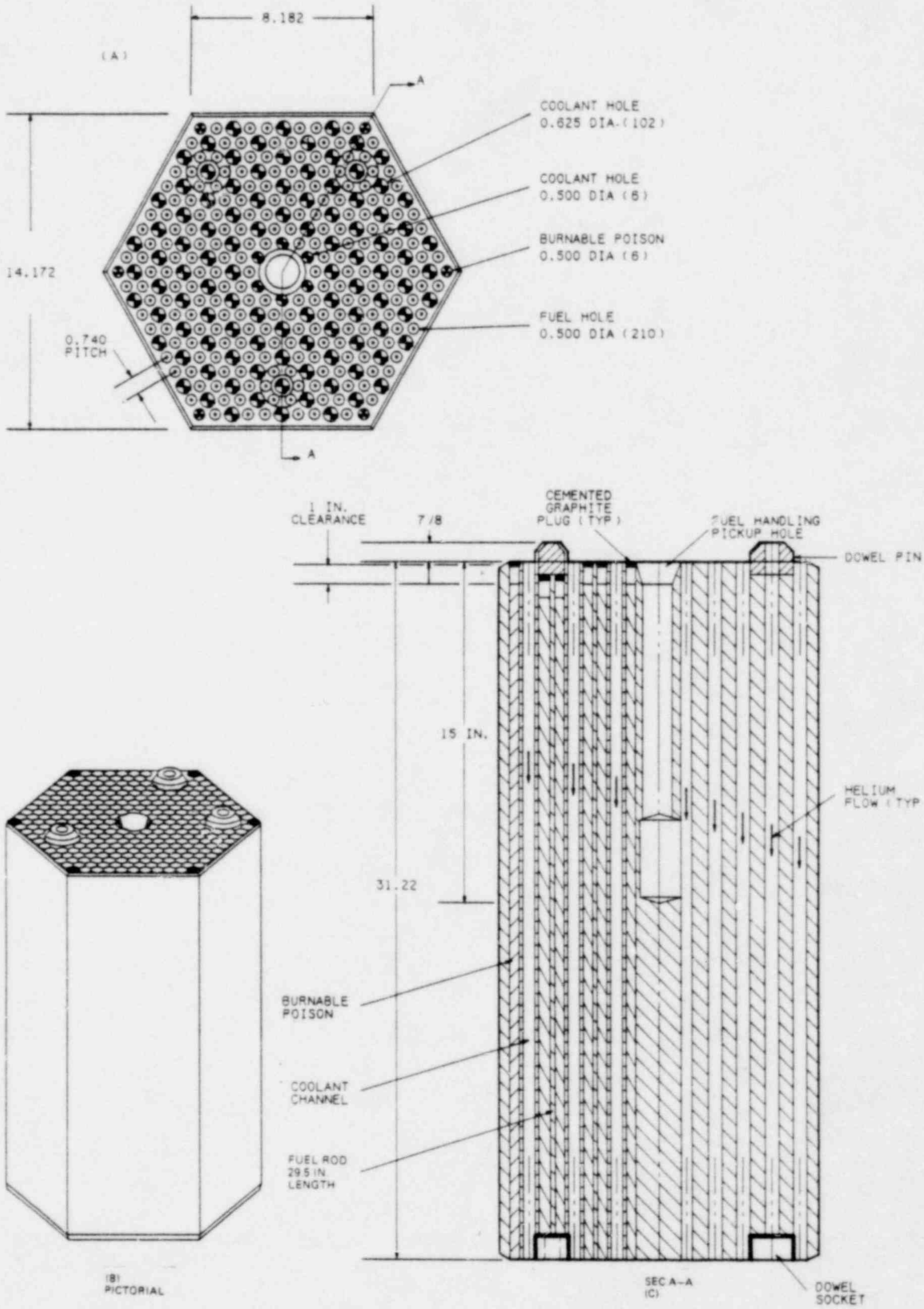


Figure 3.4-1 Fuel Element

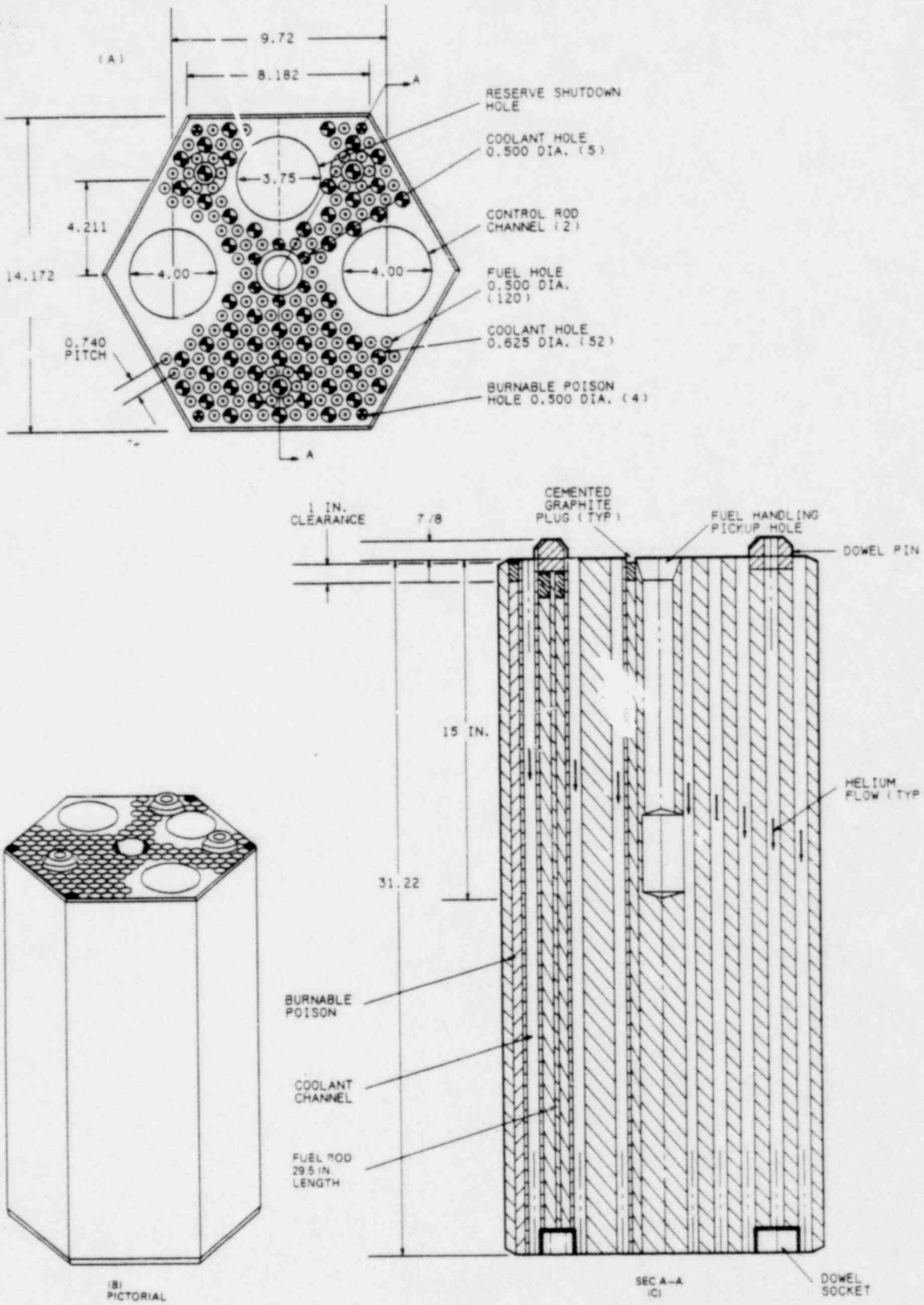


Figure 3.4-2 Control Fuel Elements

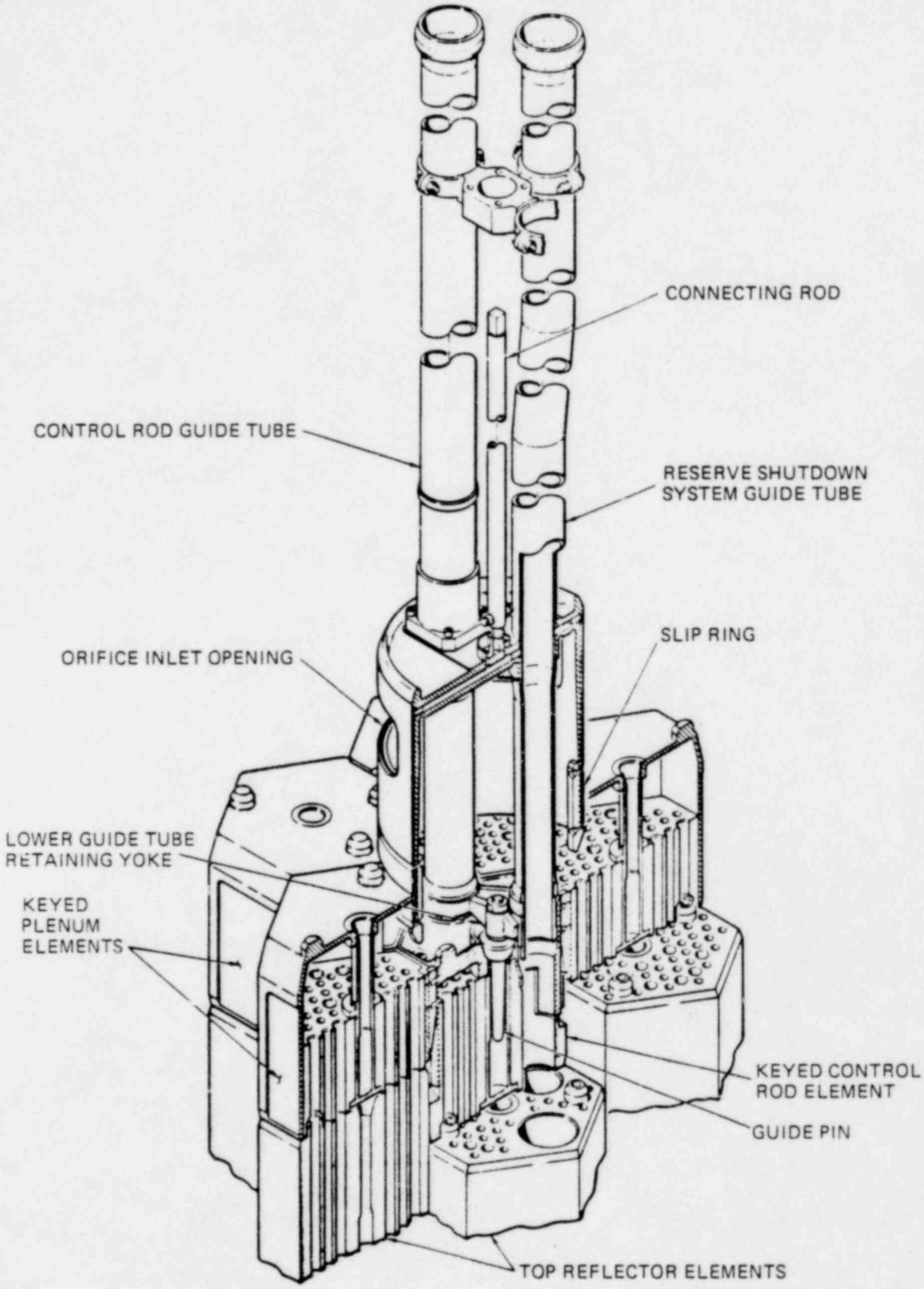


Figure 3.4-7 Top Plenum and Orifice Valve Arrangement

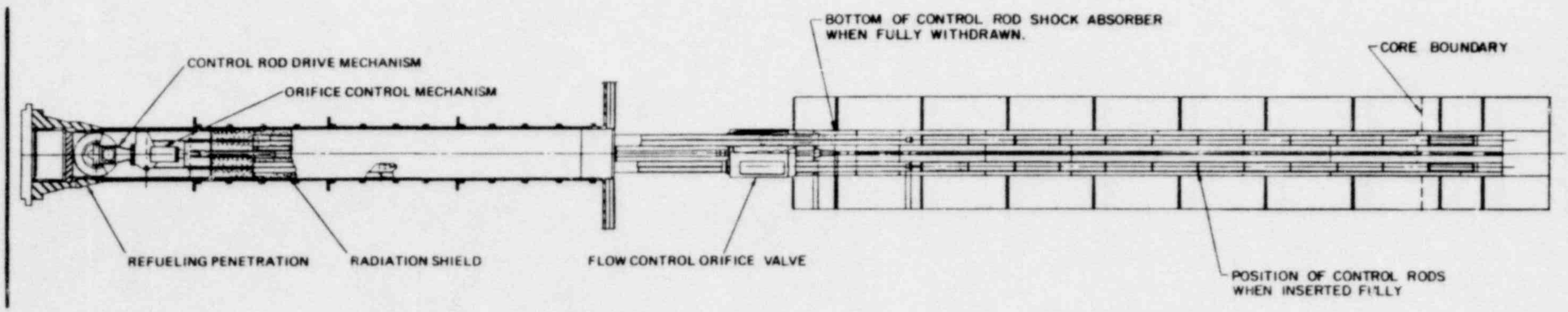


Figure 3.8-12
Control and Orificing Assembly Installation

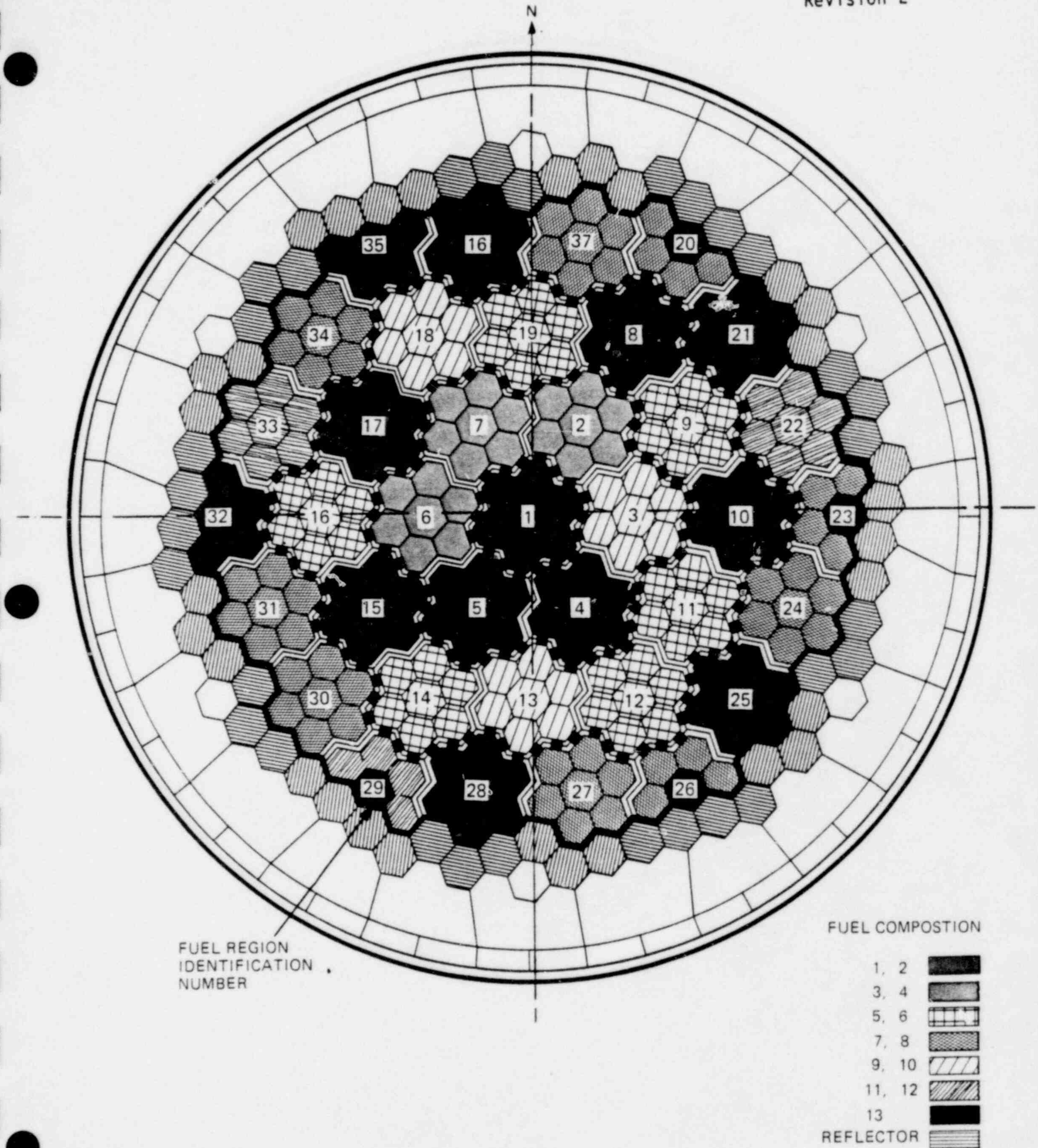


Figure 3.5-1 Initial Core Fuel Loading Distribution

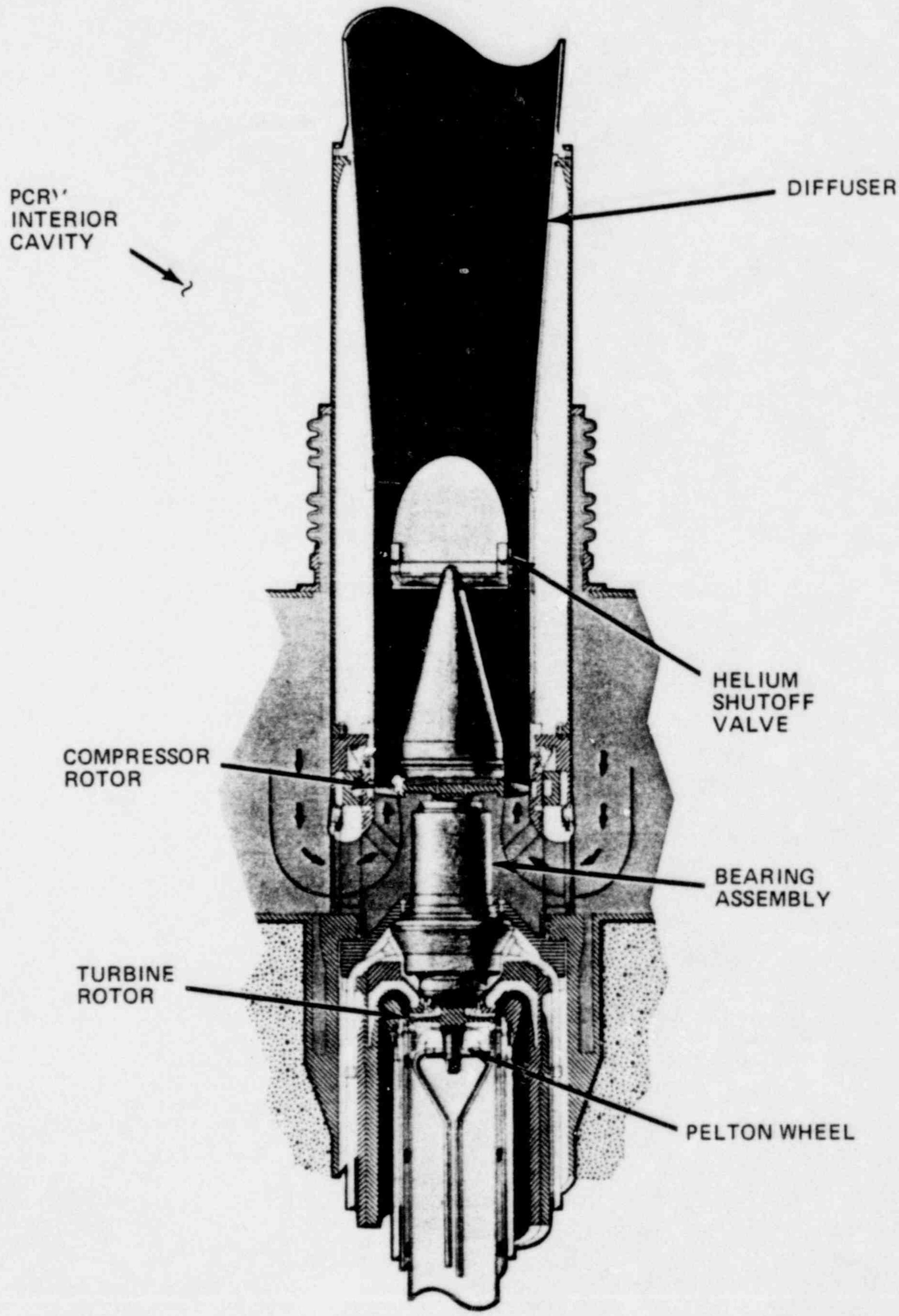


Figure 4.2-4 Helium Circulator Installation

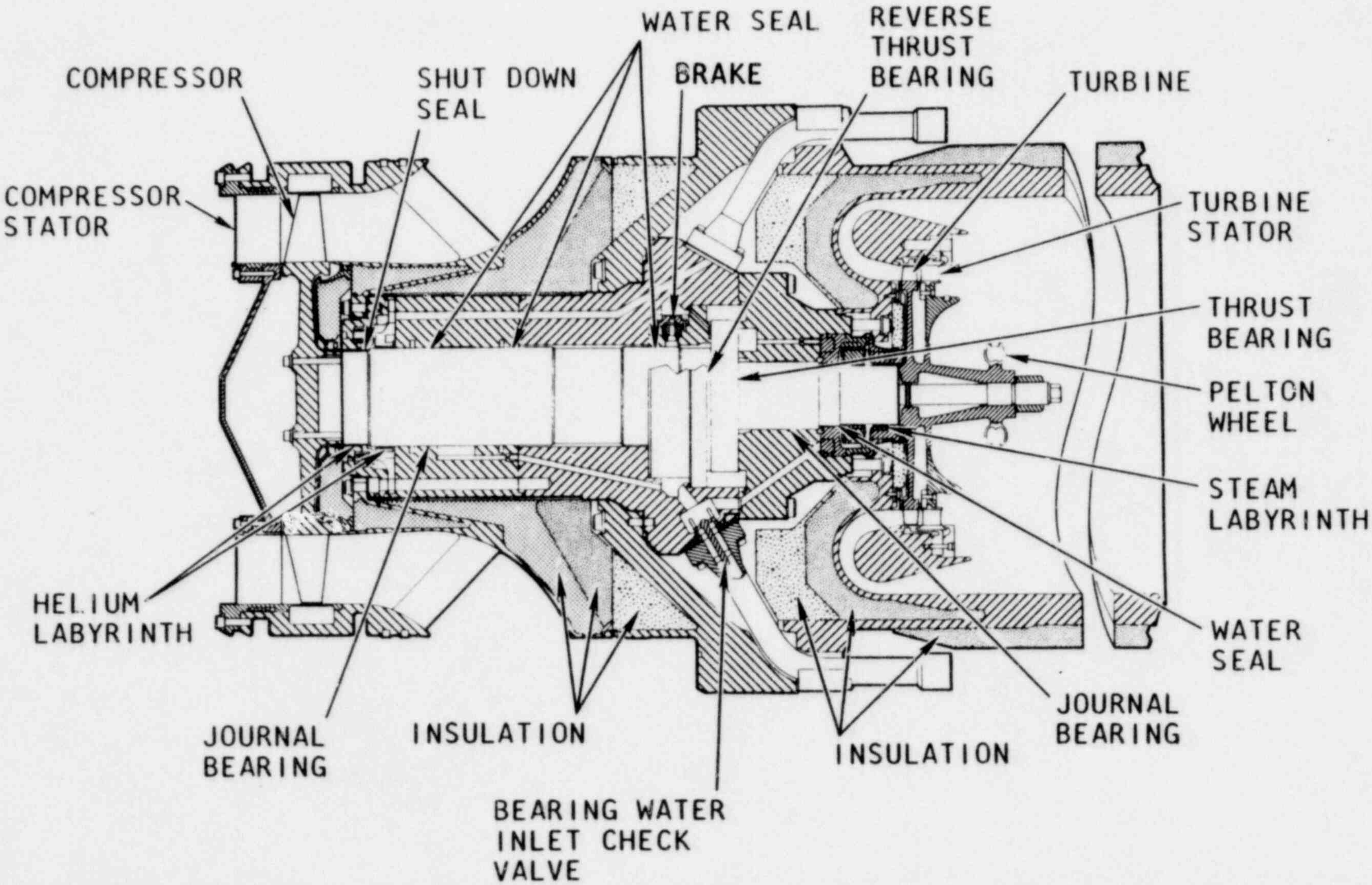


Figure 4.2-1 Helium Circulator Assembly

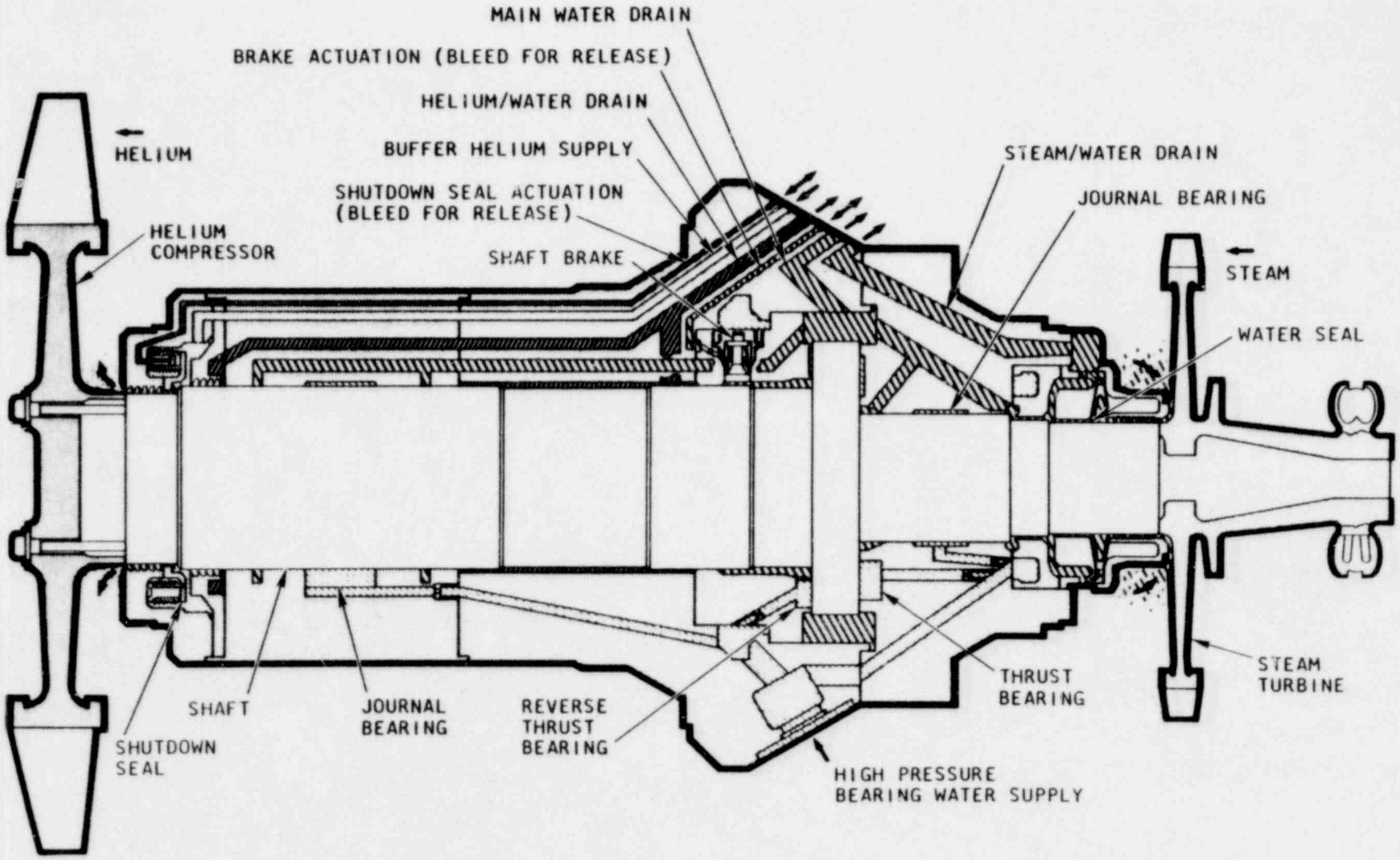


Figure 4.2-2 Helium Circulator Bearing and Seal Flow Arrangement

LC 92910

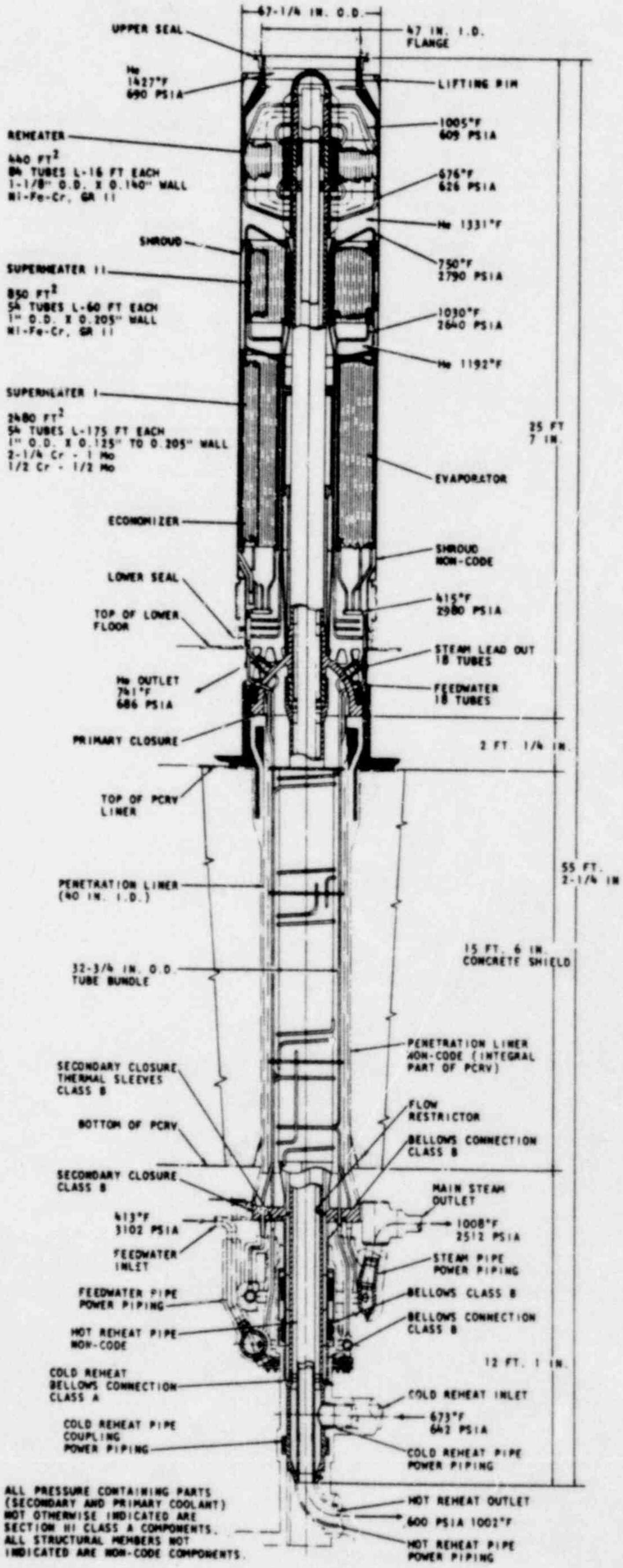


Figure 4.2-13
Steam Generator Module General Arrangement and
Code Classification

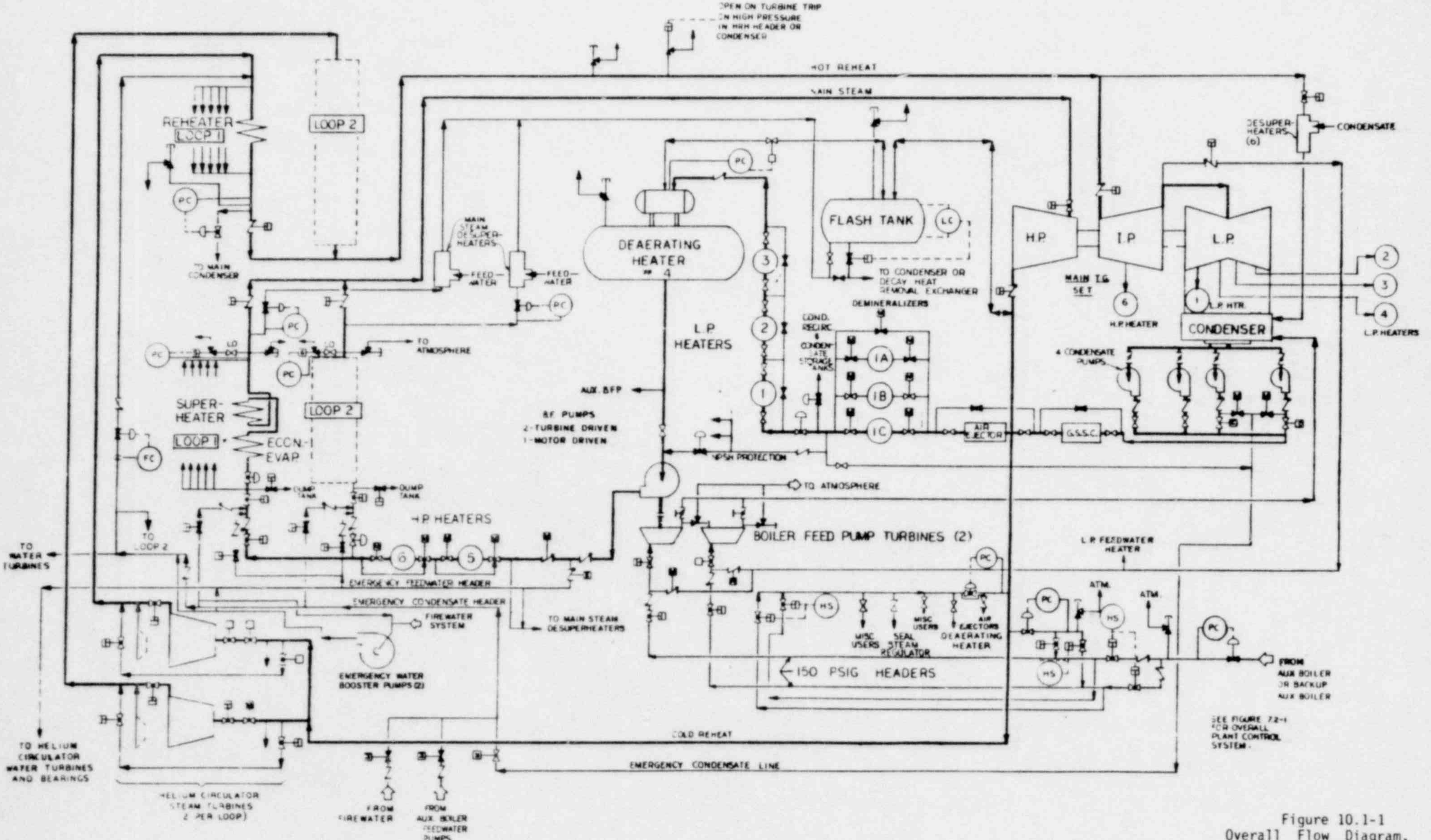


Figure 10.1-1
Overall Flow Diagram,
Secondary Coolant and Power
Conversion System

APPENDIX II

OPERATIONAL HISTORY

FSV SIGNIFICANT EVENTS

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
November, 1965 ------------------	Contracts Signed to Construct Fort St. Vrain Under Reactor Demonstration Program
October, 1966 -------------------	PSC Files Application with the Atomic Energy Commission to Construct Fort St. Vrain
July, 1967 ---------------------	Redesign of Building Structure to Accomodate a 300 MPH Tornado
September, 1967 -----------------	PSC Files With Public Utilities Commission for Certificate of Necessity and Benefits
February, 1968 ------------------	Atomic Energy Commission Issues New Design Criteria as Appendix A to 10CFR50. Fort St. Vrain Design Had to be Backfitted
April, 1968 --------------------	PSC Receives Certificate from Public Utilities Commission. Site Work Commences
July, 1968 ---------------------	PSC Requests Atomic Energy Commission to Permit Concrete Pouring for Reactor Building Foundations. Request Denied
September, 1968 -----------------	Atomic Energy Commission Issues Construction Permit. Concrete Work Begins for Reactor Building
October, 1969 -------------------	PSC Files Application with Atomic Energy Commission for an Operating License
July-August, 1970 ---------------	Atomic Energy Commission Issues New Criteria for Seismic and Environmental Testing
June, 1971 ---------------------	PSC Operator Candidates Take Atomic Energy Commission Licensing Examination
January, 1972 ------------------	Atomic Energy Commission Issues Safety Evaluation for Fort St. Vrain

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
6-28-72 through 8-7-72	Conducted First Hot Flow Test
N/A	As Result of First Hot Flow Test, Pre-Nuclear Pelton Wheels Disintegrated Due to Cavitation
8-7-72 through 5-30-73	Design and Installation of Nitrogen Pressurization System for Pelton Cavity to Prevent Cavitation and Installation of New Pre-Nuclear Pelton Wheel
5-30-73 through 8-29-73	Conducted Second Hot Flow Test
9-1-73 through 12-15-73	Replaced Pre-Nuclear Pelton Wheels With Nuclear Grade Pelton Wheels and Tested
12-27-73 through 1-16-74	Fuel Loading
1-31-74	Initial Criticality
2-15-74 through 3-31-74	Repaired and Modified Control Rod Drives to Sheared Dowels and Cap Screws on the Worm Gear Used for Removing the Control Rod Drive by the Rewind Tool
7-1-74 through 8-15-74	Static Seal Pressurization System for "A" Circulator Developed Internal Leak Necessitating Its Removal and Replacement
7-1-74	Water Admitted into PCRV Due to a Blind Flange Not Being Installed in the Helium/Water Drain on "C" Circulator

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
8-15-74 through 11-15-74 ----------------------	PCRV Dryout and Replacement of Control Rod Drive Penetration Connectors Due to Corrosion From the Water Ingress
11-15-74 through 12-31-74 ----------------------	Examination of "A" Circulator Pelton Wheel Following Replacement Earlier in Year Revealed Root Cracking at Base of Pelton Wheel. New Forged Pelton Wheels Were Installed
1-15-75 through 4-1-75 -----------------------	4,100 Gallons of Water Entered the PCRV Via the Helium Circulators. Water Was Removed
4-1-75 through 5-1-75 -----------------------	Rise to Power Testing to 2%. Control Rod Drive Temperature Problems Were Observed
5-1-75 through 6-5-75 -----------------------	An Internal (PSC) Cable Segregation Audit Was Conducted as a Results of the Browns Ferry event. Reactor Remained Shutdown
6-5-75 through 6-18-76 -----------------------	Nuclear Regulatory Commission Ordered a Full Audit of All Essential and Associated Non-Essential Cables With Respect to Compliance with the Final Safety Analysis Report. Reactor Remained Shutdown while Audit and Cable Reroute Took Place
8-1-75 through 9-30-75 -----------------------	Fifteen Control Rod Drives were Modified Due to Internal Leakage Observed During Pressure Test
8-25-75 through 9-30-75 -----------------------	"B" Circulator Replaced Due to Internal Leakage Observed During Pressure Test

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
3-10-76 through 4-30-76	Helium Leakage was Observed in the "D" Circulator Shutdown Seal Activation System
7-6-76	Initial Power Operation (Greater Than 2%)
8-3-76 through 9-19-76	"C" Circulator Replaced Due to Excessive Purified Helium Leakage From the Penetration Interspace into the Reactor Vessel
9-19-76 through 12-11-76	Rise to Power Testing and Minor Modifications to the Startup Bypass Pressure Control System and Steam/Water Dump Relay System
12-11-76	Initial Power Generator
February, 1977	Plant Shutdown to Repair Helium Purification Inlet Valves
March, 1977	Unit Returned to Service
April, 1977	Turbine Trip From 38% Power. Plant Protective System (PPS) Malfunction. Nuclear Facility Safety Committee (NFSC) Restricts Power to 30%.
August, 1977	Testing and Evaluation Complete. Nuclear Facility Safety Committee (NFSC) Lifts 30% Restriction.
October, 1977	NRC Release From 40% Power Restriction to 70%
November, 1977	First Indication of Core Thermal Fluctuations. Plant Taken to 68% Power.
December, 1977	Steam Generator Tube Leak. Reactor Shutdown.
January, 1978	Steam Generator Tube Repaired. Unit Returned to 68% Power.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
January 23, 1978 ----------------	Reactor Transient. Radiological Alert Declared. Four (4) ci Noble Gas Released. Fort St. Vrain Operation Restricted to Less Than 2% Pending Investigation.
March 29, 1978 ------------------	NRC Release Obtained to Resume Operation
April, 1978 ---------------------	Unit Returned to Service
May, 1978 -----------------------	Startup Testing Up to 70% Power Completed
Remainder, 1978 -----------------	Various Trips as Outlined. Continued Fluctuation Test Program. 70% Power Restriction.
February 8, 1979 ----------------	Reactor Shutdown. First Refueling.
May, 1979 -----------------------	Refueling Complete
July, 1979 ----------------------	Turbine Generator Placed On Line
October, 1979 -------------------	Unit Shutdown. Region Constraint Devices Installed
January, 1980 -------------------	Reactor Taken Critical. Helium Circulator Primary Seal Inoperable.
March, 1980 ---------------------	Helium Circulator Replaced. Unit Brought On Line.
May, 1980 -----------------------	Spent Fuel Shipping Begins. NRC Meeting for Fort St. Vrain Radiological Emergency Response Plan (RERP).
May 20, 1981 --------------------	Second Refueling
July, 1981 ----------------------	Refueling Complete
November, 1981 ------------------	Plant Reaches 100% Power
November, 1981 ------------------	Plant Shutdown. Helium Loop Split.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
April, 1982	Loop Split Work Completed
May, 1982	Unit Returned to Service
October, 1982	Plant Transient. Unit Down. Steam Generator Tube Leak. NRC Release From 70% Power Restriction.
January, 1983	Unit Returned to Service
February, 1983	Plant Transient. High Primary Coolant Moisture.
April, 1983	Annual Media Tours, April 7-8. INPO Emergency Appraisal, Week of April 11.
June, 1983	Annual RERP Exercise, June 15
July, 1983	Unit Back on Line, July 15
August, 1983	Emergency Preparedness Meeting, Arlington, August 9
September, 1983	Exceeded 70% Power, Problems With High Vibration on 1C Boiler Feed Pump, ECA Hearing on September 28 - Penalties Proposed by PUC Staff
October, 1983	Exceeded 70% Power, Vibration Problems Continue With 1C Boiler Feed Pump, Rate Hearings on October 5-6
November, 1983	PUC Incentive Hearings on November 16-17, PUC Staff Proposes More Severe Penalties for Fort St. Vrain. Turbine Trip, EHC Unit. Unit Recovered by mid-November.
December, 1983	Site Visit by Commissioner Bernthal on December 21. Manual Scram Firewater Deluge on Reserve Auxiliary Transformer. Unit Recovered Quickly.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
January, 1984 -------------------	End of Cycle III on January 20, 1984. Unit Shutdown for Refueling, Turbine Overhaul, and Electrical Modifications. SALP Review on January 17.
February, 1984 ------------------	PSC Corporate Management Tour. State PUC Examiner Recommends $526,000 Customer Rebate Due to Poor Operation.
March, 1984 --------------------	Failed Tendon Wires Discovered During In-Service Inspection Program
April, 1984 --------------------	Meeting with NRR, Bethesda, to Discuss Cracked Fuel Element Program
	Letter to NRC, Region IV, Prestressing System. Request to Return to Power Operation (April 12, 1984).
	NRC Release to Go to 2% Power (April 19, 1984).
	Update Letter to NRC, Region IV, Prestressing System. Request for Release From 2% Power Restrictions (April 25, 1984).
	PCRV Pressurized in Preparation to Return to Power Operation
	PCRV Depressurized and Repressurized to Change Out Control Rod Drive #12 (stuck Orifice Valve).

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
May, 1984 ------------------------	Problems With Reserve Shutdown System. PCRV Depressurized and Problems Fixed. Vessel Repressurized.
	Pulled Rods on May 4, 1984. Reactor Scram High Moisture.
	Moisture Removal in Progress.
	ACRS Site Meeting on May 17, 1984.
	The 2% power limit is removed by the Nuclear Regulatory Comission following their evaluation of the PCRV tendon wire degradation.
	Initial Cycle 4 criticality is achieved on May 16, 1984.
	Reactor power is reduced to less than 2% to repair Loop 2 helium dryer valve and leaking sulzer valves.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
June, 1984----------------------	The turbine generator is synchronized on June 12, 1984, but trips within one hour due to low steam temperature because of reactor power being limited by Technical Specification requirements on moisture. The turbine generator is placed in service on June 13, 1984, at approximately 50MW. Reactor power is increased above 30% on June 21, 1984. On June 22, 1984, the operation of the sudden pressure relay on the 4160/480V Transformer No. 1 causes a trip of the 480V A.C. Essential Bus 1A and subsequently, the 1A Helium Circulator due to a bearing water upset. Power is reduced and the circulator is recovered. With moisture increasing, helium density maintained, and helium purification system problems, the programmed pressure trip setpoint, determined by circulator inlet temperature, drops below the actual measured pressure, resulting in a reactor scram on high pressure on June 23, 1984. During the event, six of the thirty-seven control rod pairs fail to automatically insert. A powered insertion of the stuck rods is successful. Although six of the control rod pairs fail to initially insert, cold shutdown conditions are achieved with the initial scram.
July, 1984----------------------	Three of the six control rod pairs that failed to insert have their gear train and shim motors refurbished. Segment 3 spent fuel shipping commences.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
August, 1984---------------------	Refurbishment of the remaining three control rod gear train and shim motors is completed.
	The annual Radiological Emergency Response Plan (RERP) drill is performed on August 15, 1984.
September, 1984------------------	Inspection of all the control rod drive motors is begun.
October, 1984--------------------	A change to the high pressure separator on 1C helium circulator is installed.
	The PCRV is repressurized to aid in primary coolant cleanup.
November, 1984-------------------	During the test of the reserve shutdown system for Control Rod Drive #21, the boron balls do not fully discharge from the hopper. A non-emergency event report is made to the Nuclear Regulatory Commission on November 5, 1984.
December, 1984-------------------	Helium Circulator 1A is removed from the PCRV and shipped to San Diego to repair an interspace bearing water leak.
January, 1985--------------------	Preparations are made for the Control Rod Drive and Orifice Assembly (CRDOA) refurbishment and cable replacement.
February, 1985-------------------	Contract personnel begin refurbishment of CRDOA's.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
March, 1985----------------------	Helium Circulator 1A is returned from San Diego. During the repair work on the circulator, chloride stress corrosion of some of the internal bolting is discovered by GA Technologies and the affected bolts are replaced. The "Loss of Outside Electric Power" surveillance is performed on March 18, 1985. The backup power system functions as expected.
April, 1985----------------------	Helium Circulator 1A is replaced in the PCRV. Helium Circulator 1A main drain valve is removed and replaced with a digital valve and electronic controls. Helium Circulator 1B is removed from the PCRV to replace the internal bolts, and reinstalled.
May, 1985----------------------	Helium Circulator 1D is removed to replace the internal bolting and reinstalled.
June, 1985----------------------	Helium Circulator 1C is removed to replace the internal bolting and reinstalled. All control rod drive work is completed and the CRD secondary cover plates are reinstalled. The annual Radiological Emergency Response Plan (RERP) exercise is conducted on June 18, 1985. Vacuum is established on June 30, 1985.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
July, 1985-----------------------	Permission from the Nuclear Regulatory Commission to startup the reactor is recieved on July 1985. The reactor is not allowed to exceed 15% power until Environmental Qualification issues are resolved. The reactor is taken critical on July 20, 1985. A high moisture scram occurs on July 23, 1985, while trying to establish a shutdown seal on Helium Circulator 1A. The reactor remains shutdown for primary coolant cleanup. The digital valve installed on Helium Circulator 1A experiences leakage problems and is replaced with the original valve.
August, 1985---------------------	Primary coolant cleanup continues. The Nuclear Regulatory Commission advises Public Service Company not to restart the reactor until further justification on equipment qualification issues are recieved. In response, Public Service Company provides justification for operation of the reactor, not to exceed 8%, to aid in primary coolant cleanup.
September, 1985------------------	Public Service Company submits a request for a schedule extension of the Environmental Qualification Program from November 30, 1985, to March 31, 1986. Permission from the Nuclear Regulatory Commission to startup the reactor, not to exceed 8% power, is received on September 30, 1985. The reactor is taken critical that same day.

FORT ST. VRAIN
SIGNIFICANT EVENTS

Approximate Date	Event Description
October, 1985--------------------	The reactor reaches 7.8% power.
November, 1985-------------------	The reactor is shutdown for Environmental Qualification.
	The "Loss of Outside Electric Power" test is successfully completed.
	The Nuclear Regulatory Commission grants an extension of the Environmental Qualification program from November 30, 1985, to May 31, 1986, for operation at less than 35% power, subject to Nuclear Regulatory Regulation approval.
December, 1985-------------------	Segment 10 fuel is received.
	Helium circulator remote manual brake and seal valve station prefabrication is complete.
January, 1986--------------------	While returning a clearance on 1D helium circulator, a water ingress into the PCRV of approximately 300 gallons occurs.
February, 1986-------------------	Permission from Nuclear Reactor Regulation to operate at up to 35% power is received. The reactor is taken critical on February 14, 1986.
March, 1986----------------------	Reactor power is slowly increased while primary coolant cleanup efforts continue.

POWER GENERATION SUMMARY

POWER GENERATION SUMMARY

FORT ST. VRAIN

	MWH(e) GROSS(YR)	MWH(e) CUM	AVAIL* FACTOR	CAPACITY** FACTOR
July, 1976, First Reactor Operation Above 2%	0	0	0	0
December, 1976 First Electric Generation	23,842	23,842	----	---
December, 1977	261,035	284,877	30.1	13.7
December, 1978	663,393	948,270	51.4	34.8
February, 1979 End of Cycle I	109,852	1,058,122	----	----
December, 1979	250,648	1,198,918	18.8	12.8
December, 1980	730,998	1,929,916	53.8	38.6
May, 1981 End of Cycle II	400,445	2,330,361	----	----
December, 1981	819,562	2,749,478	48.1	43.1
December, 1982	635,548	3,385,026	37.3	32.5

$$\text{*Avail. Factor} = \frac{\text{Total Hours Generator On Line}}{\text{8760 Hours}}$$

$$\text{**Cap. Factor} = \frac{\text{Actual Generation, MWH (net)}}{\text{200 MW (8760 Hours)}}$$

POWER GENERATION SUMMARY

FORT ST. VRAIN

	MWH(e) GROSS(YR)	MWH(e) CUM	AVAIL* FACTOR	CAPACITY** FACTOR
December, 1983	826,546	4,211,572	52.8	25.9
January, 1984 End of Cycle III	77,412	4,288,984	----	----
December, 1984	95,144	4,306,716	7.5	1.9
October, 1985	0	4,306,716	0	0

$$\text{*Avail. Factor} = \frac{\text{Total Hours Generator On Line}}{\text{8760 Hours}}$$

$$\text{**Cap. Factor} = \frac{\text{Actual Generation, MWH (net)}}{\text{200 MW (8760 Hours)}}$$

ELECTRICAL AND THERMAL GENERATION SUMMARY

FORT ST. VRAIN

MONTH	MW(t)/MO	MW(t) CUMULATIVE	GROSS MWH(e)/MO.	GROSS MWH(e) CUMULATIVE
January, 1984	240,818.8	5,951,456.8	77,412	4,288,984
February, 1984	0.0	5,951,456.8	0	4,288,984
March, 1984	0.0	5,951,456.8	0	4,288,984
April, 1984	0.0	5,951,456.8	0	4,288,984
May, 1984	7,584.2	7,584.2	0	4,288,984
June, 1984	91,993.8	99,578.0	17,732	4,306,716
July, 1984	0.0	99,578.0	0	4,306,716
August, 1984	0.0	99,578.0	0	4,306,716
September, 1984	0.0	99,578.0	0	4,306,716
October, 1984	0.0	99,578.0	0	4,306,716
November, 1984	0.0	99,578.0	0	4,306,716
December, 1984	0.0	99,578.0	0	4,306,716

ELECTRICAL AND THERMAL GENERATION SUMMARY

FORT ST. VRAIN

MONTH	MW(t)/MO	MW(t) CUMULATIVE	GROSS MWH(e)/MO.	GROSS MWH(e) CUMULATIVE
January, 1985	0.0	99,578.0	0	4,306,716
February, 1985	0.0	99,578.0	0	4,306,716
March, 1985	0.0	99,578.0	0	4,306,716
April, 1985	0.0	99,578.0	0	4,306,716
May, 1985	0.0	99,578.0	0	4,306,716
June, 1985	0.0	99,578.0	0	4,306,716
July, 1985	109.5	99,687.5	0	4,306,716
August, 1985	0.0	99,687.5	0	4,306,716
September, 1985	0.0	99,687.5	0	4,306,716
October, 1985	24,311.6	123,999.1	0	4,306,716
November, 1985	8,947.7	132,946.8	0	4,306,716
December, 1985	0.0	132,946.8	0	4,306,716

ELECTRICAL AND THERMAL GENERATION SUMMARY

FORT ST. VRAIN

MONTH	MW(t)/MO	MW(t) CUMULATIVE	GROSS MWH(e)/MO.	GROSS MWH(e) CUMULATIVE
January, 1986	0.0	132,946.8	0	4,306,716
February, 1986	1,974.0	134,920.8	0	4,306,716
March, 1986	39,600*	174,520*	0	4,306,716
April, 1986				
May, 1986				
June, 1986				
July, 1986				
August, 1986				
September, 1986				
October, 1986				
November, 1986				
December, 1986				

*Estimated

CONTRIBUTORS TO LOST OUTPUT

DOMINANT CONTRIBUTORS TO FORT ST. VRAIN LOST OUTPUT

CATEGORY	EQUIVALENT FULL POWER HOURS LOST 1979	1980	1981	1982	1983	TOTAL	CF LOSS % TOTAL
Helium Circ System	692.6	2,827.1	710.8	152.8	756.2	5,139.5	11.73
Refueling	2,927.9	-----	1,312.9	-----	-----	4,240.8	9.68
Feedwater System	1,265.5	1,095.4	275.4	61.7	1,212.7	3,910.7	8.92
Helium Loop Split	-----	-----	1,267.4	2,328.0	-----	3,595.4	8.20
Moisture Unknown	-----	324.1	139.3	-----	3,012.1	3,475.4	7.93
70% Power Limit	73.4	355.8	766.2	981.8	290.4	2,467.6	5.63
Plant Protect Sys	35.5	108.8	152.3	1,458.6	81.8	1,837.0	4.19
Turbine/Generator	387.3	154.9	668.9	420.2	98.8	1,730.1	3.95
Rtr Bldg/Seismic	759.9	825.4	-----	18.5	-----	1,603.8	3.66
Region Constraints	1,461.2	-----	-----	-----	-----	1,461.2	3.33
Misc Systems	15.5	698.7	58.8	299.8	43.6	1,116.4	2.55
Electrical System	108.9	72.0	47.0	24.0	630.6	882.5	2.01
PCRV Penetrations	-----	0.0	717.6	120.0	-----	837.6	1.91
Steam Generators	-----	107.7	-----	684.3	25.8	817.8	1.87
Main Steam System	230.2	2.0	78.8	4.0	304.6	619.6	1.41
Control Rod Drives	3.0	-----	-----	342.3	-----	345.3	0.79
Operator Training	56.0	56.0	72.0	48.0	-----	232.0	0.53
Testing	56.4	91.4	62.4	-----	-----	210.2	0.48
Fires	-----	-----	130.5	-----	-----	130.5	0.30
Grid/System Demand	-----	17.2	12.0	30.5	-----	59.7	0.14
TOTAL	8,073.3	6,736.5	6,472.3	6,974.5	6,456.6	34,713.1	79.21
UNIT OUTAGE HOURS	7,112.5	4,072.9	4,545.0	5,493.8	4,131.1	25,331.3	----

$$\text{CF Loss \%} = \frac{\text{Total Equivalent Full Power Hours Lost}}{(4 \times 8{,}760) + 8{,}784}$$

FORT ST. VRAIN CONTRIBUTORS TO LOST OUTPUT

CATEGORY	EQUIVALENT FULL POWER HOURS LOST 1979	1980	1981	1982	1983	TOTAL	CF LOSS % TOTAL
Refueling	2,927.9	-----	1,312.9	-----	-----	4,240.8	9.68
Circ Loop Split	-----	-----	1,267.4	2,328.0	-----	3,595.4	8.20
Moisture Unknown	-----	324.1	139.3	0.0	3,012.1	3,475.4	7.93
70% Power Limit	73.4	355.8	766.2	981.8	290.4	2,467.6	5.63
Circ Buff He Dryer	439.2	1,093.1	243.8	134.1	405.4	2,315.6	5.28
Plant Protect Sys	35.5	108.8	152.3	1,458.6	81.8	1,837.0	4.19
Rtr Bldg/Seismic	759.9	825.4	-----	18.5	0.0	1,603.8	3.66
Feedwater Chemistry	1,004.5	433.0	106.9	31.7	-----	1,576.1	3.60
Instll Core Constrt	1,461.2	-----	-----	-----	-----	1,461.2	3.33
Feedwater Control	-----	465.1	37.6	-----	550.8	1,053.5	2.40
Circ Static Seal	-----	936.0	-----	-----	-----	936.0	2.14
Electrical System	108.9	72.0	47.0	24.0	630.6	882.5	2.01
Feedwater Pumps	198.8	-----	-----	-----	661.9	860.7	1.96
Circ Bearing Water	0.0	294.1	208.0	4.9	335.5	892.5	1.92
Penetrat He Leaks	-----	0.0	717.6	120.0	-----	837.6	1.91
Steam Generators	-----	107.7	-----	684.3	25.8	817.8	1.87
Circulator Other	168.0	353.4	197.3	-----	15.3	734.0	1.67
Turbine I&C	90.0	86.0	-----	420.2	26.8	623.0	1.42
Main Steam System	230.2	2.0	78.8	4.0	304.6	619.6	1.41
Turbine Valves	-----	33.9	448.3	-----	2.0	484.2	1.10
Turbine Vib & Test	242.3	-----	220.6	-----	-----	462.9	1.06
Cntrl & Orif Ass.	3.0	-----	-----	342.3	-----	345.3	0.79
Circ Speed Control	85.4	150.5	61.7	13.8	-----	311.4	0.71
Unknown	15.5	110.6	54.2	85.3	43.6	309.2	0.71
Miscellaneous Sys	-----	163.1	-----	120.0	-----	283.1	0.65
Circulating Water	-----	283.0	-----	-----	-----	283.0	0.65
Operator Training	56.0	56.0	72.0	48.0	-----	232.0	0.53
Feedwater Other	-----	101.9	110.9	-----	-----	212.8	0.49
Fluctuations & Tsts	56.4	91.4	62.4	-----	-----	210.2	0.48
Feedwater Valves	62.2	95.4	20.0	30.0	-----	207.6	0.47
Main Generator	55.0	35.0	-----	-----	70.0	160.0	0.37
He Purification Sys	-----	99.7	-----	46.5	0.0	146.2	0.33
Fires	-----	-----	130.5	-----	-----	130.5	0.30
Grid/System Demand	-----	17.2	12.0	30.5	-----	59.7	0.14
Moisture Monitors	-----	-----	4.6	48.0	-----	52.6	0.12
Condenser	0.0	42.3	0.0	-----	-----	42.3	0.10
TOTAL	8,073.3	6,736.5	6,472.3	6,974.5	6,456.6	34,713.1	79.21
UNIT OUTAGE HOURS	7,112.5	4,072.9	4,545.0	5,493.8	4,131.1	25,331.3	----

$$\text{CF Loss \%} = \frac{\text{Total Equivalent Full Power Hours Lost}}{(4 \times 8{,}760) + 8{,}784}$$

FORT ST. VRAIN CONTRIBUTORS TO LOST OUTPUT

EQUIVALENT FULL POWER HOURS LOST

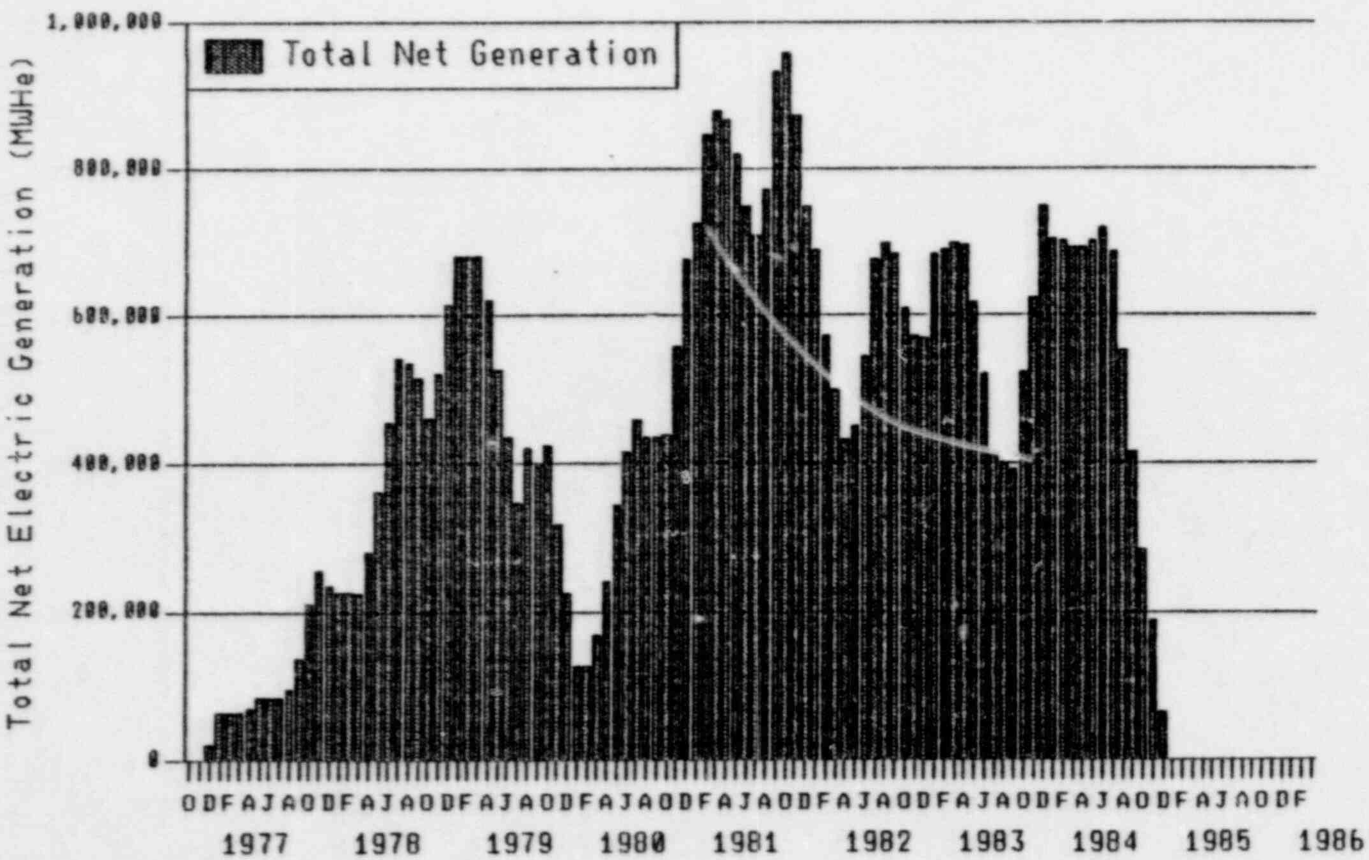
CATEGORY	1984	1985	1986	TOTAL	CF LOSS % TOTAL
Electrical System	30.9	-------	_______	30.9	0.16
Refueling	1,154.5	-------	-------	1,154.5	5.86
PCRV Tendons	624.0	-------	-------	624.0	3.17
Orifice Valves	242.3	-------	-------	242.3	1.23
Control Rod Drives and Helium Circulator Bolting Changeout	4,611.2	4,828.3	-------	9,438.5	47.9
Helium Circulators	408.0	-------	-------	408.0	2.07
Moisture	465.7	1,722.4	1,216.5	3,404.6	17.28
Misc Systems	622.4	-------	-------	622.4	3.16
Environmental Qualification	-------	2,178.0	896.0	3,074.0	15.6
TOTAL	8,159.0	8,728.4	2,112.5	18,999.9	96.43
UNIT OUTAGE HOURS	7,924.1	8,760.0	2,160.0	18,844.1	95.64

$$\text{CF Loss \%} = \frac{\text{Total Equivalent Full Power Hours Lost}}{16080}$$

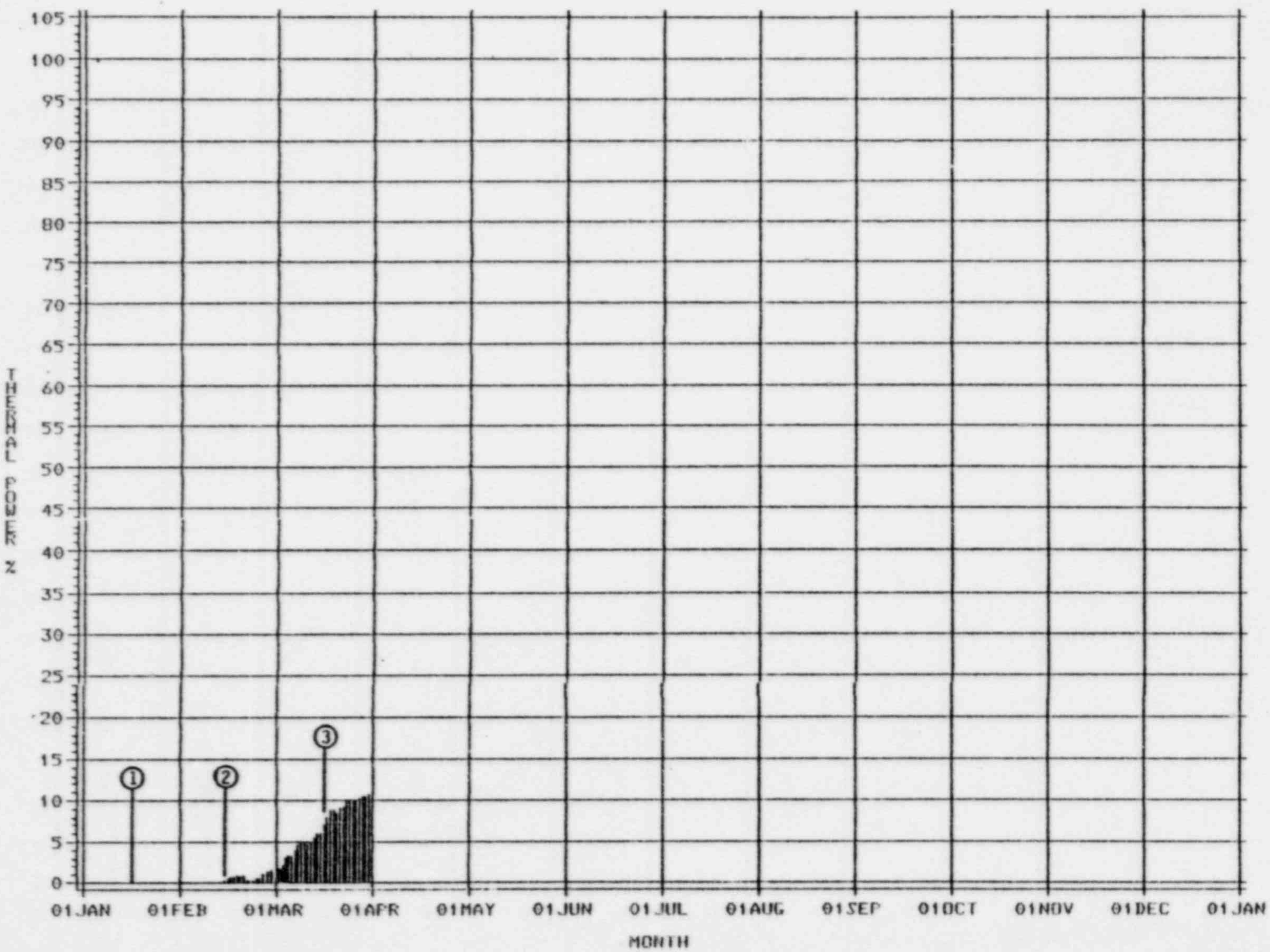
(January 1, 1984 to November 1, 1985)

OPERATIONAL HISTORY

PUBLIC SERVICE COMPANY OF COLORADO
FORT ST. VRAIN NUCLEAR GENERATING STATION
12 MONTH MOVING TOTAL NET GENERATION



1986 THERMAL POWER %



1986

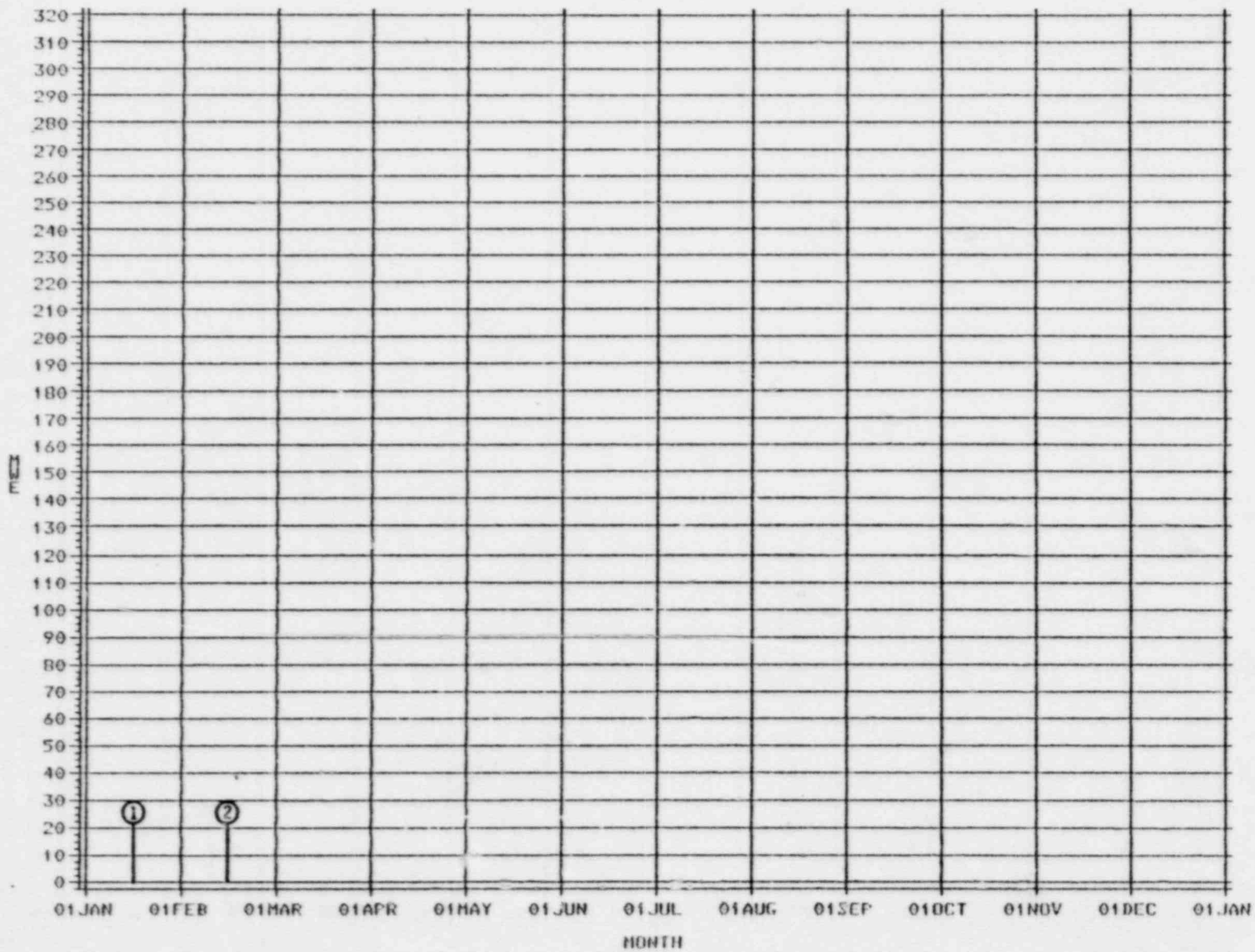
THERMAL POWER (%)

1. Environmental Qualification modifications.

2. Permission to startup the reactor, not to exceed 35%, received from the Nuclear Regulatory Commission on February 7. Reactor taken critical on February 14.

3. Primary coolant/cleanup/rise to power.

1986 DAILY AVERAGE NET GENERATION (MWE)



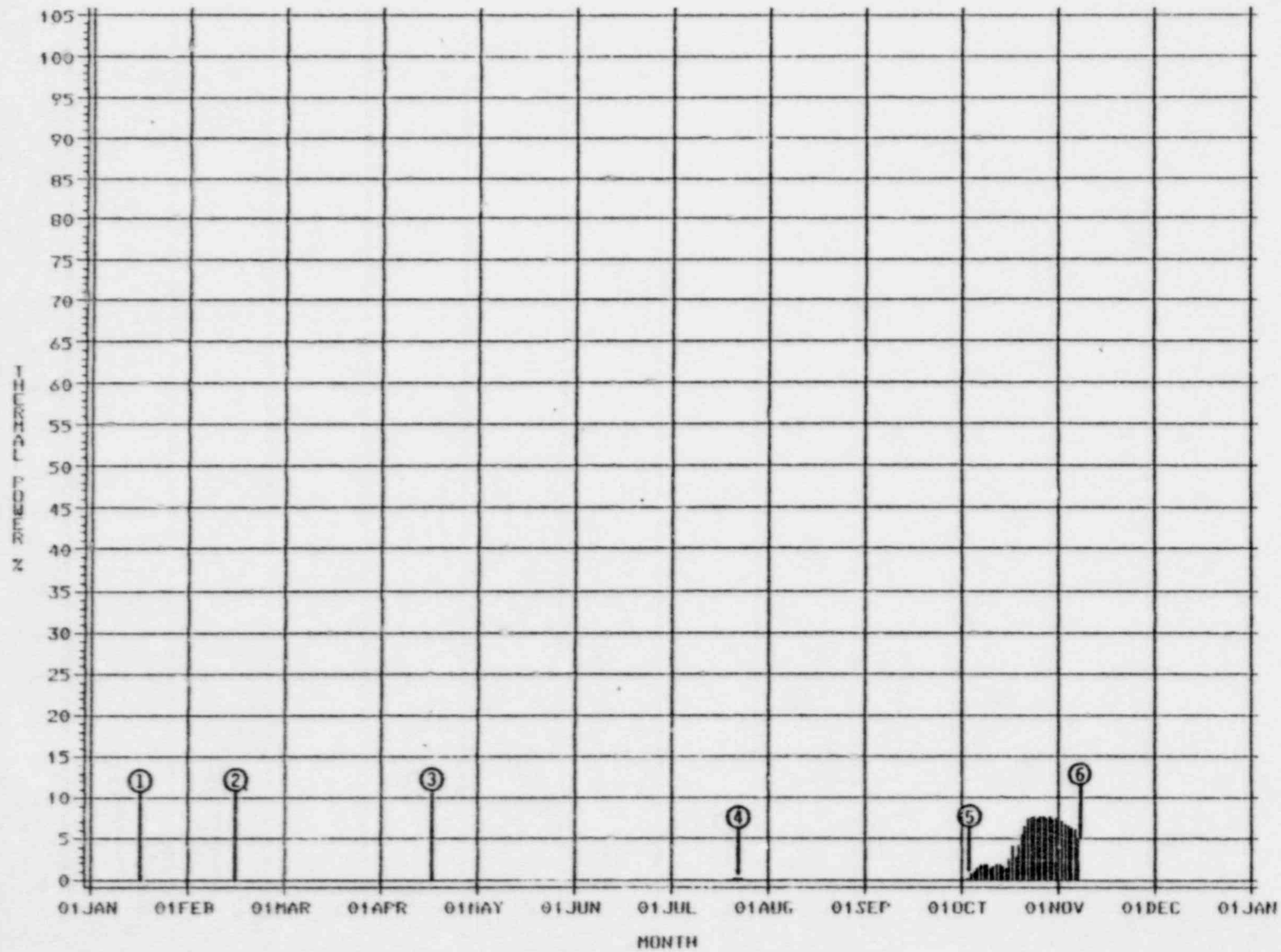
1986

DAILY AVERAGE NET GENERATION (MWe)

1. Environmental Qualification modifications.

2. Permission to startup the reactor, not to exceed 35%, received from the Nuclear Regulatory Commission on February 7. Reactor taken critical on February 14.

1985 THERMAL POWER %



1985

THERMAL POWER %

1. Investigation of six control rod drives that failed to automatically scram during the June 23, 1984, reactor pressure high scram.

2. Control rod drive refurbishment.

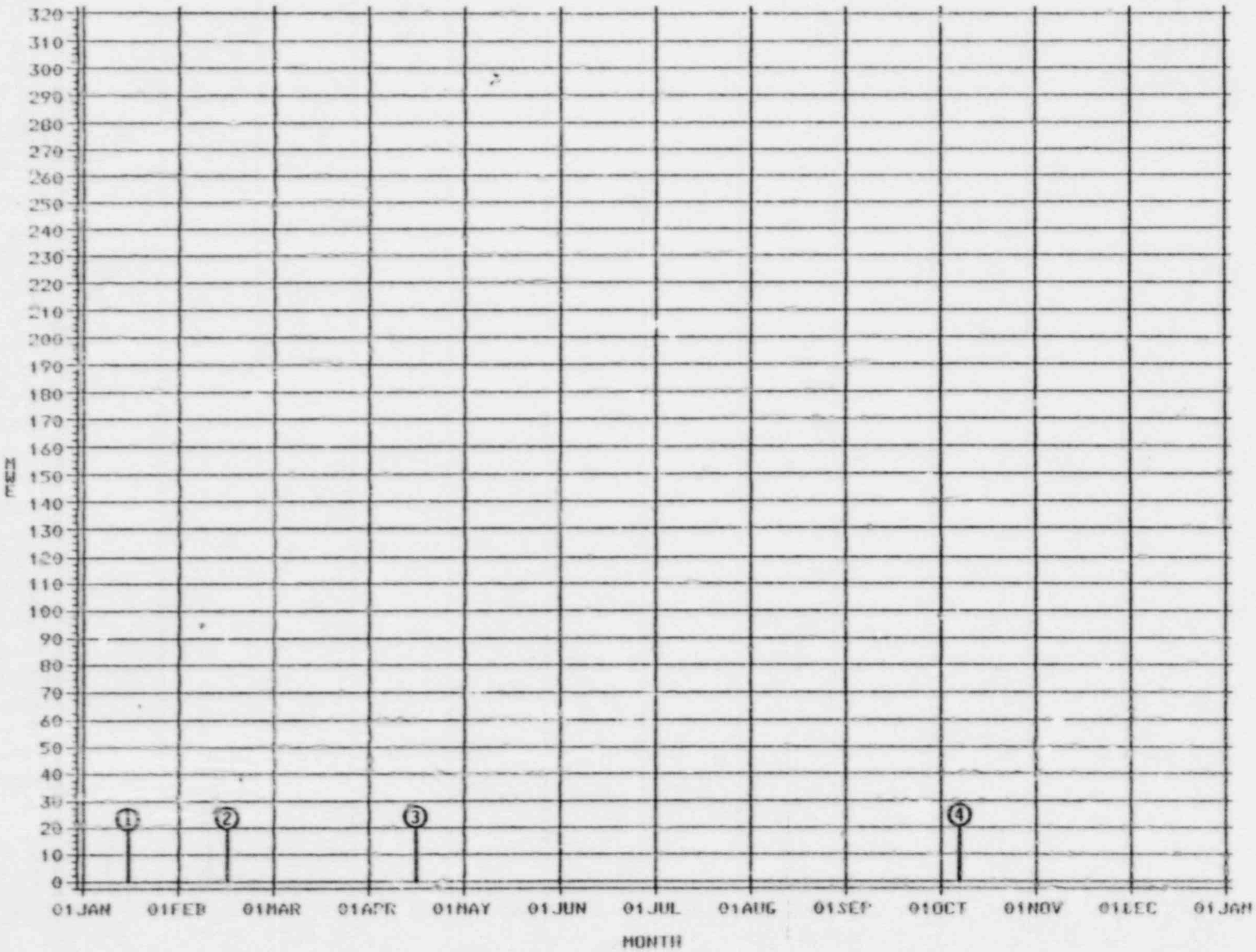
3. Control rod drive refurbishment and circulator bolting changeout.

4. Reactor taken critical on July 21. Reactor scrammed due to high moisture on July 24.

5. Reactor taken critical on September 30. Reactor scrammed due to loss of auxiliary boilers on October 1. Reactor taken critical on October 2.

6. Reactor shutdown on November 7 for Environmental Qualification.

1985 DAILY AVERAGE NET GENERATION (MWE)



1985

DAILY AVERAGE NET GENERAITON (MWe)

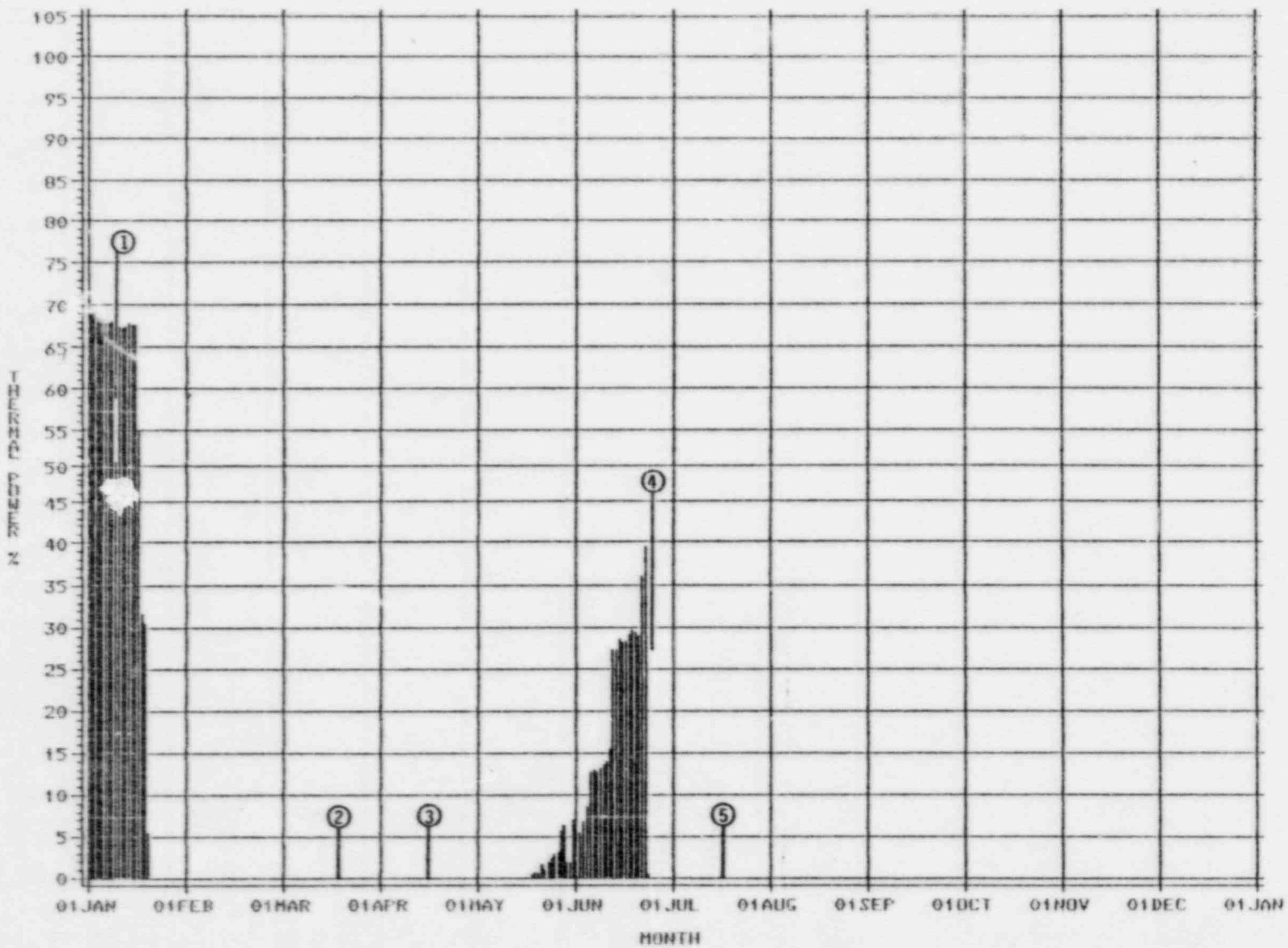
1. Investigation of six control rod drives that failed to automatically scram during the June 23, 1984, reactor pressure high scram.

2. Control rod drive refurbishment.

3. Control rod drive refurbishment and circulator bolting changeout.

4. Environmental Qualification modifications.

1984 THERMAL POWER %



1984

THERMAL POWER %

1. Turbine generator trip due to amplidyne failure.

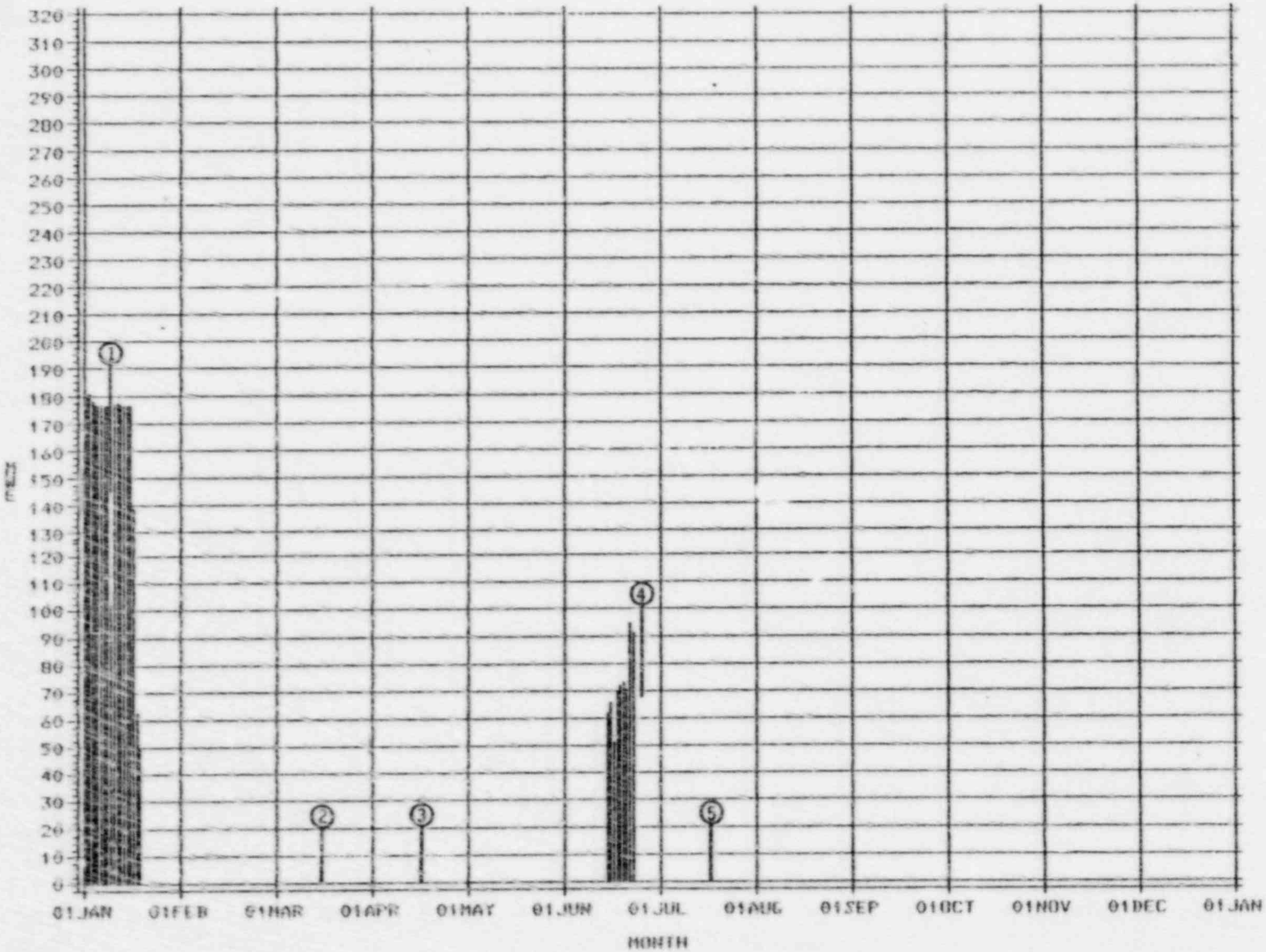
2. Refueling outage, turbine generator overhaul, "A" helium circulator changeout, routine corrective and preventive maintenance.

3. Continue refueling outage, turbine generator overhaul, "A" helium circulator changeout, PCRV tendon surveillance, routine corrective and preventive maintenance.

4. 1A helium circulator trip resulted in a water ingress to the primary coolant. A subsequent reactor pressure high scram occurred during a power decrease following the moisture ingress.

5. Investigation of six control rod drives that failed to automatically scram during the June 23, 1984, reactor pressure high scram.

1984 DAILY AVERAGE NET GENERATION (MWE)



1984

DAILY AVERAGE NET GENERATION (MWe)

1. Turbine generator trip due to amplidyne failure.

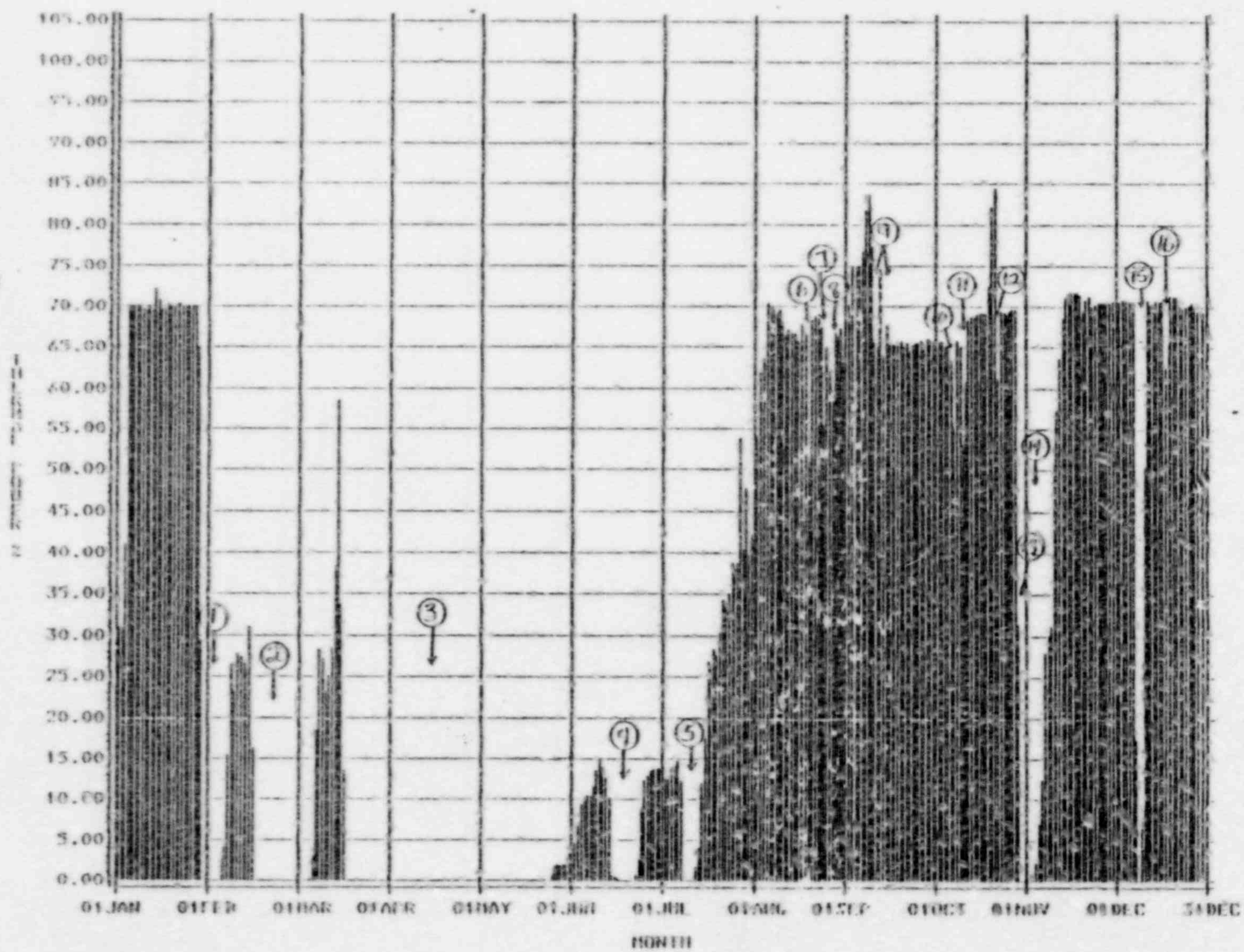
2. Refueling outage, turbine generator overhaul, "A" helium circulator changeout, routine corrective and preventive maintenance.

3. Continue refueling outage, turbine generator overhaul, "A" helium circulator changeout, PCRV tendon surveillance, routine corrective and preventive maintenance.

4. 1A helium circulator trip resulted in a water ingress to the primary coolant. A subsequent reactor pressure high scram occurred during a power decrease following the moisture ingress.

5. Investigation of six control rod drives that failed to automatically scram during the June 23, 1984, reactor pressure high scram.

1983 THERMAL POWER %



1983

THERMAL POWER %

1. Reactor scram due to moisture ingress to the PCRV following a helium circulator system upset.

2. Manual reactor scram and turbine-generator trip upon loss of "B" instrument power inverter. Continued shutdown due to high primary coolant impurity levels.

3. Reactor scram from high moisture. Remained shutdown for maintenance to "D" helium circulator.

4. Reactor manually scrammed for maintenance to the circulating water system.

5. Manual scram for maintenance to Loop 2 intercept valve.

6. Loss of electro-hydraulic control power.

7. "A" circulator trip due to seal malfunction.

8. Loss of back up bearing water on Loop 1. (recovery)

9. Excessive vibration on "C" boiler feed pump.

10. Maintenance on "A" boiler feed pump (replace XEF transmitter).

11. Maintenance on "A" boiler feed pump governor control.

12. Maintenance on "C" boiler feed pump governor control.

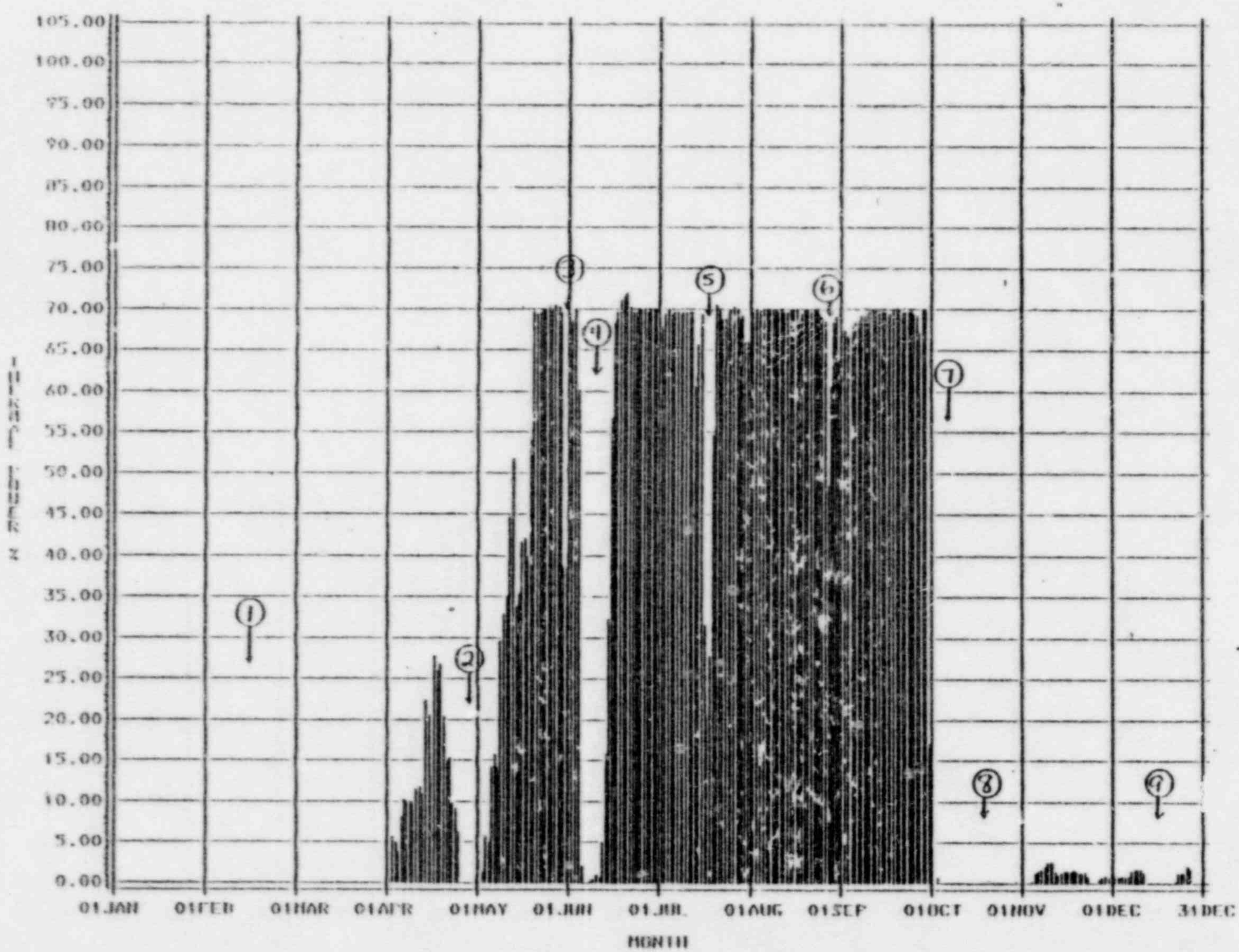
13. Reactor scram on high moisture.

14. Continue outage for surveillance testing.

15. Manual scram following activation of the firewater deluge system at RAT.

16. Repaired #5 hot reheat header bypass valve.

1982 THERMAL POWER %

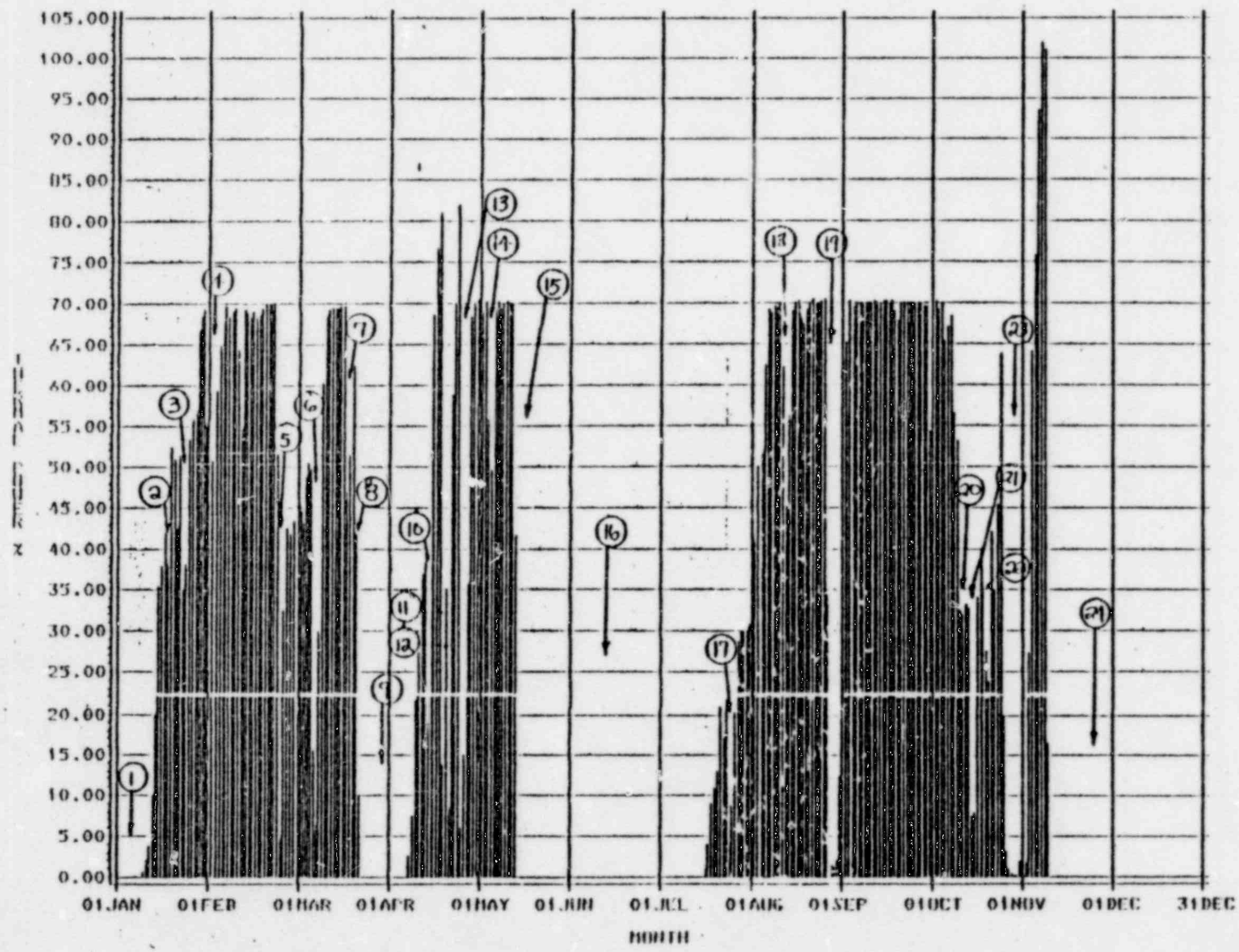


1982

THERMAL POWER %

1. Continued loop-split modification.
2. Investigation of system 46 leakage, and CRD-19 replacement.
3. Reduction of power due to primary coolant oxidants.
4. Loop 1 shutdown followed by manual scram.
5. Reactor scram and recovery.
6. Turbine generator trip and recovery.
7. Loop 1 shutdown followed by a reactor scram.
8. Continuation of shutdown (#7) for internal reactor and secondary maintenance.
9. Steam Generator module B-2-3 leak repair.

1001 THERMAL POWER %



8505460078

<u>1981</u>

<u>THERMAL POWER %</u>

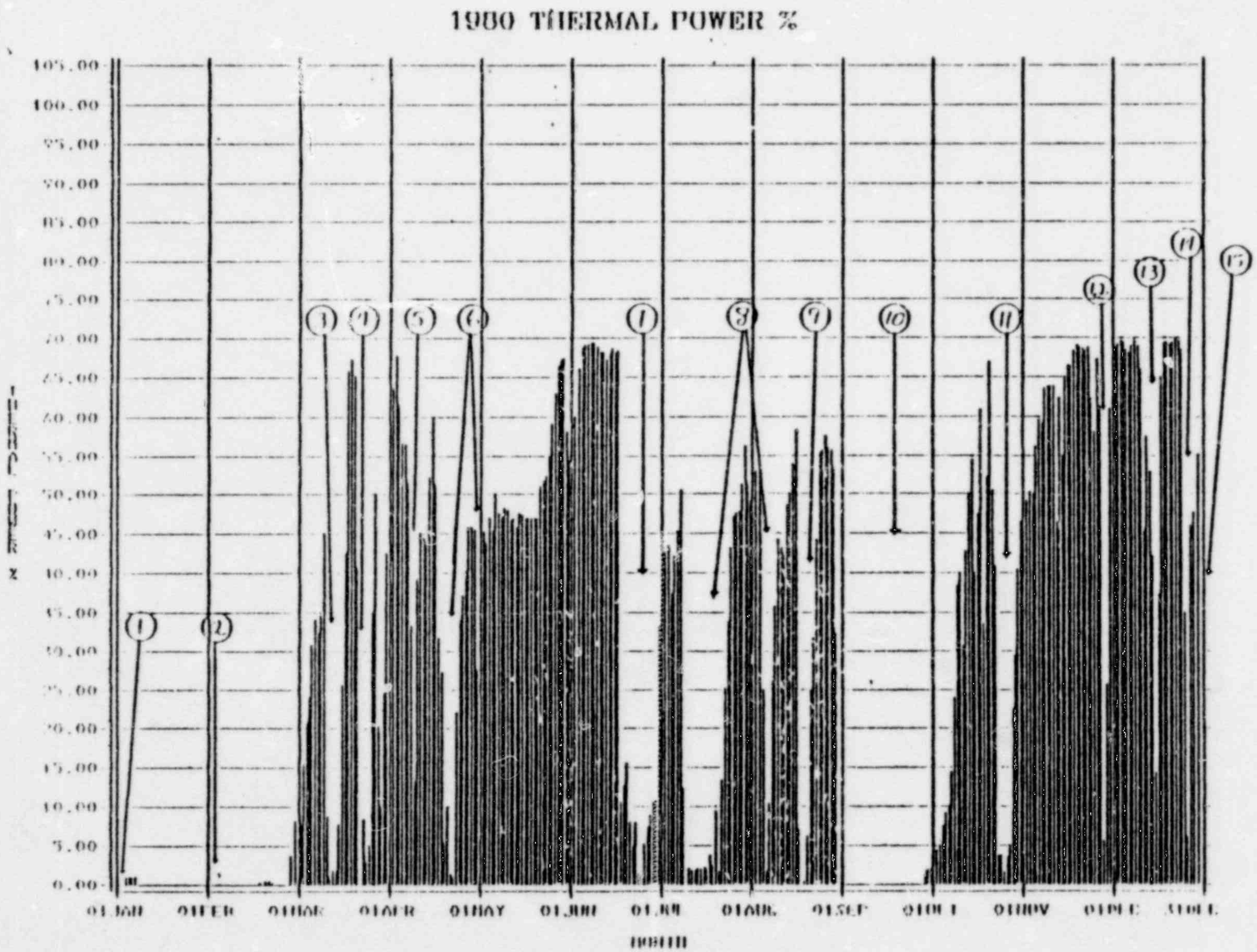
1. Continued turbine reheat valve shutdown.
2. Power reduction for moisture.
3. Shutdown for feedwater leak.
4. Power reduction for moisture.
5. Hot reheat scram.
6. Loop 2 sample valves installed.
7. Power reduction for fluctuation testing, RT-500K.
8. Turbine trip during PMO-4-w.
9. Shutdown due to excessive purified helium leakage following recovery from turbine trip.
10. ARS Scram due to RMCC1 loss.
11. HRH Scram due to 1D circulator trip.
12. Loop II trip and recovery.
13. HRH Scram due to 1A circulator trip.
14. Turbine off line for Control Circuit modification.
15. High vibration trip on turbine generator. Start of refueling outage on 5-21-81.
16. Shutdown for refueling.
17. Startup following refueling.
18. "A" circulator out of service for SV-2105 repair.
19. Turbine trip and reactor scram during attempted repair of SV-2105. Also cable repair after construction fire in cable tray.
20. Turbine off line for isolation of #5 feedwater heater leak.
21. Reactor scram on two-loop-trouble, turbine trip.
22. Loop II trip and recovery.

1981

THERMAL POWER %

23. Turbine off line, reactor < 2.0% of power for excessive purified helium leak from B.2.3 5/6 penetration.

24. Shutdown for loop-split modification.



1980 THERMAL POWER %
% THERMAL POWER
105.00
100.00
95.00
90.00
85.00
80.00
75.00
70.00
65.00
60.00
55.00
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
01JAN
01FEB
01MAR
01APR
01MAY
01JUN
01JUL
01AUG
01SEP
01OCT
01NOV
01DEC
31DEC
MONTH
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

<u>1980</u>

<u>THERMAL POWER %</u>

1. Shutdown to recover from scram.
2. Replace B circulator (ruptured static seal).
3. Scram due to cooling tower line rupture.
4. Instrument problems and loss of vacuum.
5. Power reduction due to moisture.
6. Turbine off due to loop shutdowns.
7. Loop shutdown, stayed down, due to moisture.
8. Reactor scram due to trip of 4 circulators.
9. Shutdown due to hydraulic oil leak and fire.
10. Planned shutdown for maintenance/surveillance testing.
11. Reactor scram due to loop shutdown during surveillance testing.
12. Turbine taken off line for HRH drain line repair.
13. Turbine taken off line to check for steam generator leak.
14. Repair feedwater trim valve.
15. Shutdown for valve V-7207 repair.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
760803	1,183.8	Specification LCO 4.2.9 limit for group VII penetration (helium circulator C-2103) was reached. Leakage at primary seal exceeded 400 pounds/day. Circulator is being removed and replaced with spare.
760921	795.5	Superheat steam bypass pressure control valves stuck. Shutdown to test. Disassembled valves to repair. Replaced air operators with self-contained hydraulic operators.
761025	177.7	Superheat steam bypass pressure control valves stuck. Shutdown to test. Disassembled valves to repair. Replaced air operators with self-contained hydraulic operators.
761101	340.5	NSSS hydraulic oil to actuate major valves developed heat exchanger leaks. Shutdown to remove, repair, and reassemble heat exchangers. Certain valve actuation solenoids replaced with better application at same time.
761123	215.5	As the result of unexpected sag in instrument bus 1 voltage and ensuing scram, a design deficiency in the steam water dump/loop isolation circuitry was discovered. Circuitry modification under consideration. (See Reportable Occurrence Report No. 50-267/76-01 for details.)
N/A	164.0	Conducting power ascension tests during this time.
761201	117.8	As the result of unexpected sag in instrument bus 1 voltage and ensuing scram, a design deficiency in the steam water dump/loop isolation circuitry was discovered. Circuitry modification under consideration. (See Reportable Occurrence Report No. 50-267/76-01 for details.)
761205	18.4	Conducting power ascension tests prior to placing turbine generator on line.
761211	18.4	Turbine generator taken off line to correct instrumentation and relay wiring errors. Reactor not shutdown.
761212	0.1	Turbine generator taken off line to check lube oil system. Reactor not shutdown.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
761212	2.1	One helium circulator tripped resulting in main steam temperature unbalance between loops. Turbine generator manually tripped. Power level reduced manually.
761213	0.7	Turbine generator taken off line to correct oil leak on generator. Reactor not shutdown.
761213	0.2	Turbine generator taken off line to place automatic voltage regulator in service. Reactor not shutdown.
761215	9.2	Turbine generator taken off line to correct turbine valve program. Reactor not shutdown.
761215	8.5	Turbine generator tripped due to high vibration. Reactor not shutdown.
761218	0.7	Turbine generator taken off line to perform over speed tests. Reactor not shutdown.
761219	28.5	Turbine generator taken off line to investigate primary seal leak on "C" helium circulator. (Supplement to Abnormal Occurrence Report No. 50-267/76-25.) Reactor not shutdown.
761227	13.5	During test, electrohydraulic turbine control system hydraulic pressure loss tripped turbine generator. Reactor not shutdown.
770130	1,434.4	Scheduled maintenance and surveillance testing. Helium circulator "C" and "D" penetration bolts were re-torqued during shutdown. Also repaired gas leak in E-2302 containment well. (See Reportable Occurrence Report No. 50-267/76-04(30) for details.) Repair degradation discovered in helium purification system isolation valves. (See Reportable Occurrence Report No. 50-267/77-09(14).)
770331	.5	Reactor was not shutdown. Overspeed test of turbine generator was performed.
770331	42.0	Instrument line on hydraulic power system ruptured. Manual scram due to possible loss of control of one-half of hydraulically operated secondary system valves.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
770408	707.3	Turbine generator trip from unidentified cause resulted in automatic scram. (See Reportable Occurrence Report No. 50 67/77-14(14).) Startup delayed to complete required maintenance on HV-2249 and HV-225..
770512	37.0	Lost vacuum in main condenser and manually scrammed.
770514	40.1	Automatic scram induced by simulated signal required by power ascension test program.
770522	1,465.5	Scheduled shutdown for Nuclear Regulatory Commission operator license tests and maintenance.
770723	325.4	Scram test as part of startup test program.
770806	41.2	Scram test as part of startup test program.
770813	1.3	Spurious turbine generator trip. Power reduced automatically by control systems.
770813	102.9	Plant Protective System problem resulted in loop shutdown during performance of scheduled surveillance test.
770818	35.1	Plant Protective System problem resulted in loop shutdown during performance of scheduled surveillance test.
770819	16.1	Spurious trip of turbine generator.
770824	283.6	Lost reheat steam flow during test of main turbine reheat stop valves. Valve positions incorrect for turbine load.
770908	79.7	Loop shutdown because of loose electrical connection. Main turbine taken off line to recover. Reactor not shutdown.
770912	2.3	Loop shutdown from primary coolant to secondary coolant flow mismatch. Main turbine taken off line to recover. Reactor not shutdown.
770923	3.6	Loop shutdown caused by test failure. Main turbine taken off line to recover. Reactor not shutdown.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
770926	5.6	Loop shutdown occurred during trouble shooting of Plant Protective System. Main turbine taken off line to recover. Reactor not shutdown.
771005	4.3	Shutdown one loop to repair small steam leak at valve grease fitting.
771010	1.6	Spurious loop shutdown during surveillance testing. Main turbine taken off line to recover loop. Reactor not shutdown.
771010	3.5	Main turbine trip from low steam temperature. Failed pressure switch indicated higher than actual load, removing trip bypass. Reactor not shutdown.
771023	2.7	Main turbine trip on overspeed during system upset following trip of interstate tie. Reactor not shutdown.
771025	46.3	Scram and main turbine trip during surveillance test. Spurious scram.
771027	1.6	Main turbine trip on low steam temperature. Operator was increasing load at too fast a rate.
771031	1.3	Loop shutdown during surveillance test. Main turbine taken off line to recover loop. Reactor shutdown.
771031	303.1	Loop shutdown from spurious helium circulator trip. Reactor reduced to less than 2% power for maintenance and modification to Plant Protective System.
771116	21.8	Main turbine generator trip. Indicated cause low main steam pressure. Pressure was not low and involved instruments were in calibration. No cause for trip identified.
771117	63.7	Loop shutdown caused by surveillance test. During reactor power reduction to recover loop, valve operator failure caused loss of helium circulator steam drives. Reactor was manually scrammed.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
771130	1,042.7	Primary coolant moisture increase due to steam generator tube leak. Manual shutdown of reactor, automatic scram, occurred after reactor was subcritical. (See Reportable Occurrence Report No. 50-267/77-42(14).)
780112	18.8	Main turbine tripped due to malfunction of electrohydraulic control system.
780123	1,709.8	Level controller malfunction resulted in introduction of water into primary coolant and high moisture scram. Unplanned release in excess permitted by Technical Specifications accompanied scram.
780406	1.4	Turbine overspeed test. Reactor not shutdown.
780408	5.8	Spurious turbine trip. Problem in fast closing IV circuit of electrohydraulic control system not identified. Reactor not shutdown.
780409	1.8	Spurious turbine trip. Problem in fast closing IV circuit of electrohydraulic control system not identified. Reactor not shutdown.
780412	0.8	Turbine trip during electrohydraulic control system test of fast closing IV's. Reactor not shutdown.
780412	6.7	Turbine trip during electrohydraulic control system test of fast closing IV's. Reactor not shutdown.
780412	1.3	Turbine trip during electrohydraulic control system test of fast closing IV's. Reactor not shutdown.
780415	N/A	Power reduction. One loop shutdown to repair feedwater isolation valve.
780419	22.9	Turbine taken off line to recover loop shutdown from repair of feedwater isolation valve. Reactor not shutdown.
780430	N/A	Power reduction to make modification to main steam temperature controller. Reactor not shutdown.
780504	N/A	Power reduction during loop shutdown to repair leaking feedwater strainer.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
780506	35.5	Turbine taken off line for recovery of shutdown loop. Reactor not shutdown.
780508	35.1	Spurious scram during surveillance testing of Plant Protective System. Faulty test instrument.
780510	13.35	Power reduction followed by turbine shutdown due to high moisture in the primary coolant resulting from buffer helium dryer malfunction. The reactor was not shutdown.
780524	N/A	Power reduction due to loop shutdown caused by feedwater control valve going closed. Failure of feedwater flow controller closed valve.
780526	32.65	Turbine taken off line for recovery of shutdown loop. Reactor not shutdown.
780606	133.7	Reactor shutdown for operator training and license examination.
780629	118.7	Reactor scram and turbine trip due to loss of instrument bus.
780704	1.1	Turbine generator trip due to electrical noise spike. Reactor not shutdown.
780714	60.9	"C" circulator tripped when "B" logic bus was powered up. "D" circulator was not running. The loop shutdown caused a feedwater upset. The turbine generator was manually tripped, and the reactor manually scrammed.
780726	N/A	Power reduction necessary due to high oxidant concentration. Cause of oxidant problem currently under investigation.
780731	415.0	Fault in 480 volt transformer 1A resulted in loss in instrument bus 3. Turbine generator automatically tripped. Reactor was manually scrammed.
780817	17.2	Turbine generator taken out of service due to high primary coolant oxidant concentration. Cause of oxidant problem currently under investigation.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
780820	32.8	Spurious electrical noise spike tripped moisture monitor while redundant monitors were manually tripped. Reactor automatically scrammed.
780822	0.9	Turbine generator tripped on electrical system upset. Reactor was not shutdown.
780823	5.4	Turbine generator taken out of service due to high primary coolant oxidant concentration. Reactor power reduced. Cause of oxidant problem currently under investigation.
780824	0.8	Turbine generator tripped on low main steam temperature, caused by temperature detector setpoint drift. Detector setpoint reset. Reactor was not shutdown.
780826	31.4	Turbine generator manually tripped and reactor shutdown begun due to hydraulic oil leak. Leak repaired before reactor was shutdown.
780908	635.5	Routine plant shutdown for maintenance and testing.
781012	29.3	Surveillance testing caused unexpected turbine generator load transient. Transient caused automatic trip of turbine generator and Loop 1 shutdown. Reactor was not shutdown.
781017	351.8	"A" 480 volt essential transformer tripped due to internal fault. Turbine generator automatically tripped. Reactor was manually scrammed.
781102	0.4	During performance of special testing, low main steam temperature caused an automatic trip of the turbine generator. Reactor was not shutdown.
781114	19.9	During power reduction, excessive differential temperatures between hot reheat and main steam temperatures caused a high bearing vibration trip of the turbine generator. Reactor was not shutdown.
781129	228.6	Buffer helium upset caused automatic trip of two circulators and the turbine generator. Reactor was manually scrammed.

UNIT SHUTDOWN SUMMARY

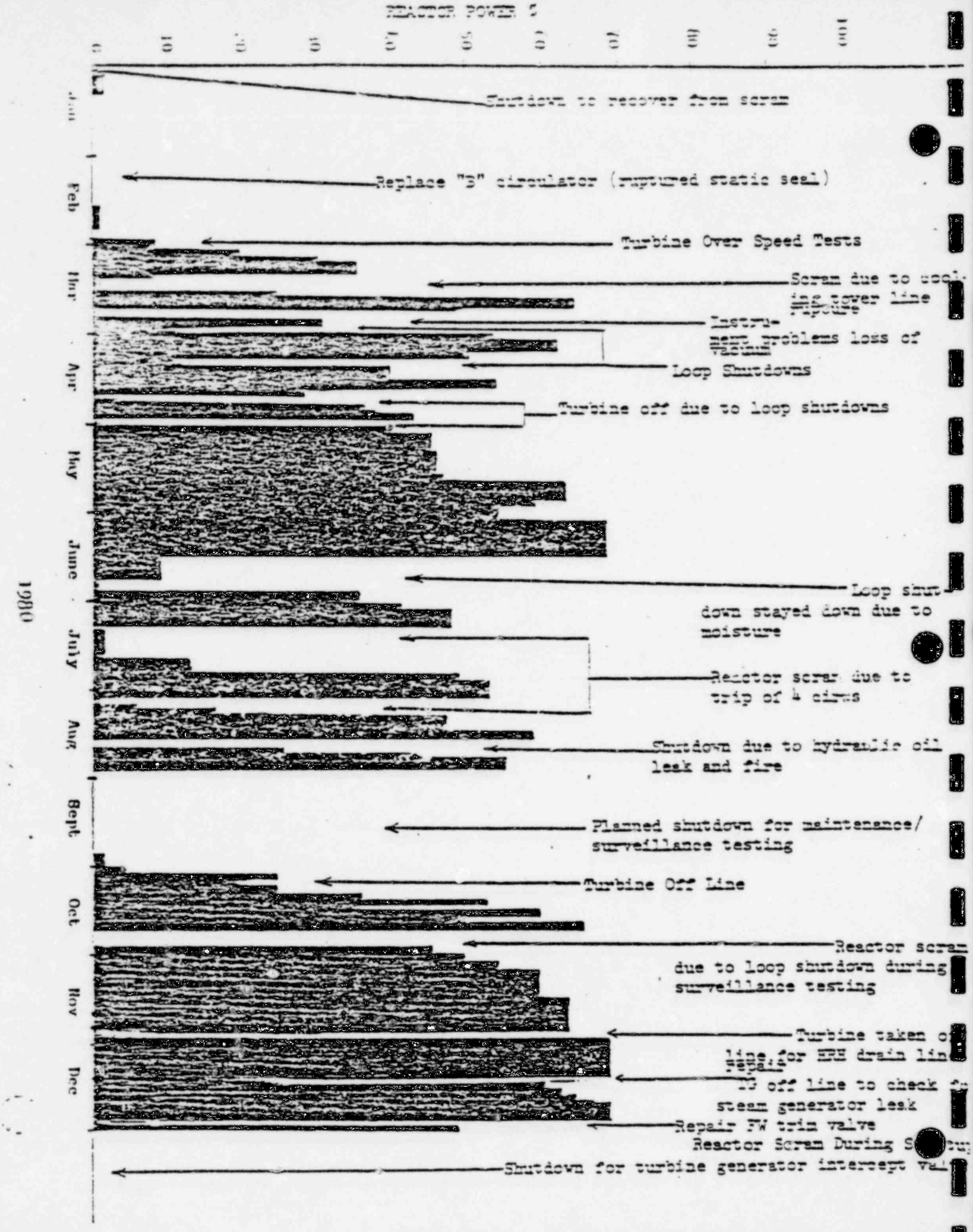
DATE	DURATION (HOURS)	DESCRIPTION
781224	N/A	Buffer helium dryer purge valve developed seat leakage. Reactor power and turbine generator load reduced while repairs were effected.
790103	N/A	"D" circulator tripped during performance of routine surveillance. Reactor power and turbine generator load reduced to recover circulator.
790119	70.8	Loop 2 was shutdown to repair feedwater valve for steam generator. Turbine generator was taken out of service and reactor power reduced to recover Loop 2 after valve repairs were completed.
790130	14.8	During performance of electrical maintenance, a voltage transient in "B" instrument bus caused Loop 1 shutdown and reactor scram. Loop 1 was recovered and reactor operations resumed.
790201	4,134.4	"B" boiler feedpump developed excessive gland seal leakage and was declared inoperable. "C" boiler feedpump had been inoperable since January 5, 1979. LCO 4.3.2 requires two boiler feedpumps to be operable during power operation. Controlled shutdown was begun followed by a manual scram at 2% reactor power. Repairs to the feedpumps in progress. Shutdown continued for duration of refueling. First turbine generation following refueling occurred 7/23/79.
790724	47.5	Turbine generator taken off line due to field ground relay problems.
790726	1.9	Turbine generator taken off line to perform overspeed tests.
790728	53.0	Turbine generator tripped from high vibration. Loop 2 shutdown occurred. Reactor power reduced to 2% for Loop 2 recovery.
790731	76.8	While transferring to partial arc on main turbine generator, throttle pressure dropped and load decreased 20MW. During recovery, three circulators tripped, Loop 2 shutdown, reactor scrammed, and turbine tripped.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
790811	24.1	While reducing power to recover a tripped circulator, hot reheat reactor scram and turbine trip occurred.
790817	68.4	An instrument panel was shorted to ground and tripped, resulting in reactor scram and turbine trip.
790824	45.9	Turbine generator taken off line as reactor power was reduced to isolate cause of high primary coolant moisture.
790901	743.4	Due to inconsistencies discovered in random sample of safety-related piping, Public Service Company elected to initiate an orderly shutdown of the plant.
791014	231.0	Turbine tripped on low steam temperature.
791026	1,600.5	Scheduled plant shutdown for maintenance and installation of region constraint devices.
800101	1,600.5 (1979)	
	1,538.8 (1980)	Scheduled shutdown for maintenance and region control device installation continued from 1979. After completion of scheduled work, but before return to power, 1B helium circulator static seal bellows ruptured and replacement was started. Replacement complete February 16, 1980.
800306	4.2	Turbine overspeed tests.
800311	123.8	Ruptured distribution pipe at circulating water tower caused loss of condenser cooling.
800321	56.8	Problems in PPS. Spurious hot reheat radiation alarm caused Loop 2 shutdown when reset. Received hot reheat high temperature scram when Loop 1 attemperation was shut off.
800324	49.2	Loss of condenser vacuum due to boiler feedpump turbine vent/drain.
800328	53.2	Buffer system upset. 1A circulator trip. Activity increase in low pressure separator. Shutdown Loop 1.

UNIT SHUTDOWN SUMMARY

DATE	DURATION (HOURS)	DESCRIPTION
800408	30.0	Loop shutdown while setting up to warm one circulator.
800417	0.6	Spurious trip from module changeout.
800425	5.9	Spurious loop shutdown. Turbine off to recover.
800430	18.8	Loop shutdown when normal bearing water pumps were restorted after low surge tank level trip.
800617	313.4	Loop shutdown caused by circulator trip on buffer-mid-buffer. Recovery delayed while awaiting repair of ruptured PDT and cleanup of primary coolant moisture.


REACTOR POWER %
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70
80
90
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1980
Jan
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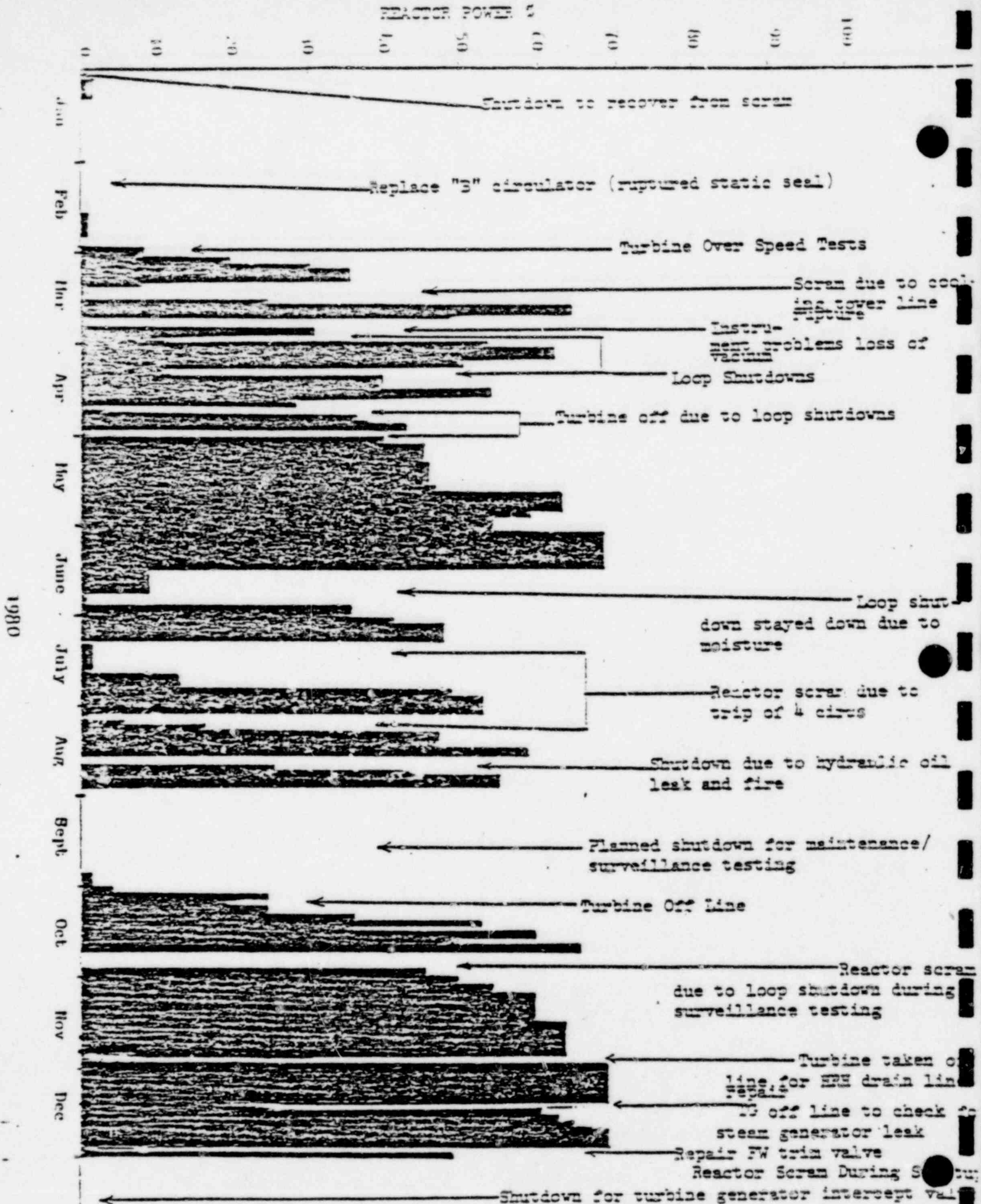
June
July
Aug
Sept
Oct
Nov
Dec
Shutdown to recover from scram
Replace "B" circulator (ruptured static seal)
Turbine Over Speed Tests
Scram due to cooling tower line rupture
Instrument problems loss of vacuum
Loop Shutdowns
Turbine off due to loop shutdowns
Loop shutdown stayed down due to moisture
Reactor scram due to trip of 4 circs
Shutdown due to hydraulic oil leak and fire
Planned shutdown for maintenance/ surveillance testing
Turbine Off Line
Reactor scram due to loop shutdown during surveillance testing
Turbine taken off line for HRH drain line repair
TG off line to check for steam generator leak
Repair FW trim valve
Reactor Scram During Startup
Shutdown for turbine generator intercept valve



REACTOR POWER %
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1980
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Turbine off due to loop shutdowns
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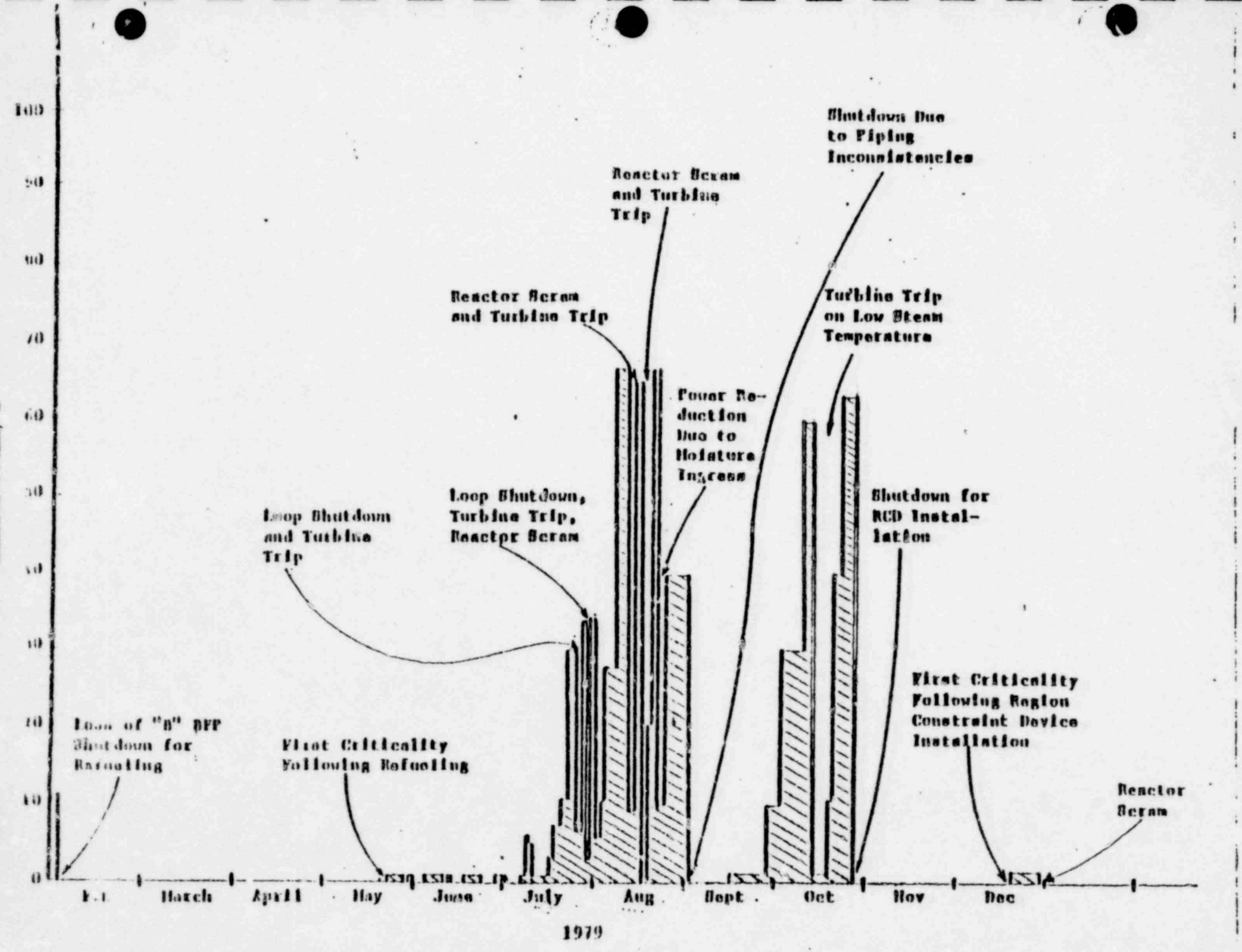

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Loss of "B" BFP Shutdown for Refueling
First Criticality Following Refueling
Loop Shutdown and Turbine Trip
Loop Shutdown, Turbine Trip, Reactor Scram
Reactor Scram and Turbine Trip
Reactor Scram and Turbine Trip
Power Reduction Due to Moisture Ingress
Shutdown Due to Piping Inconsistencies
Turbine Trip on Low Steam Temperature
Shutdown for RCD Installation
First Criticality Following Region Constraint Device Installation
Reactor Scram
March
April
May
June
July
Aug
Sept
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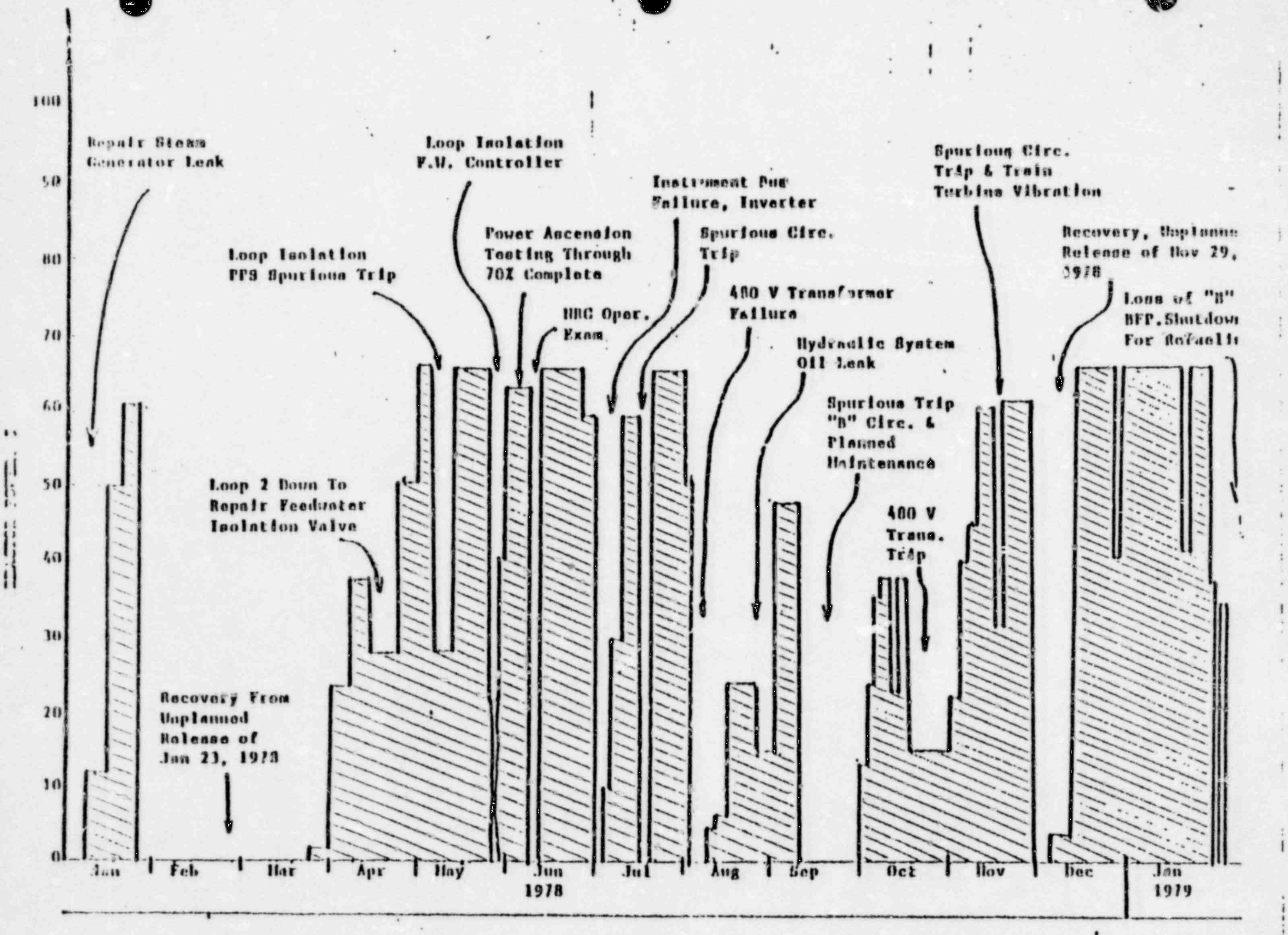
Nov
Dec
1979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Repair Steam Generator Leak
Loop Isolation F.W. Controller
Loop Isolation PPS Spurious Trip
Power Ascension Testing Through 70% Complete
NRC Oper. Exam
Instrument Bus Failure, Inverter
Spurious Circ. Trip
400 V Transformer Failure
Hydraulic System Oil Leak
Spurious Trip "B" Circ. & Planned Maintenance
400 V Trans. Trip
Spurious Circ. Trip & Train Turbine Vibration
Recovery, Unplanned Release of Nov 29, 1978
Loss of "B" BFP. Shutdown For Refuelin
Loop 2 Down To Repair Feedwater Isolation Valve
Recovery From Unplanned Release of Jan 23, 1978
Jan
Feb
Mar
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May
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1978
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Sep
Oct
Nov
Dec
Jan
1979

PROFILE OF REACTOR POWER VERSUS DATE