Metropolitan Edison Company
Post Office Box 480
Middletown, Pennsylvania 17057
717 944-4041

August 30, 1979

John G. Kemeny, Chairman
President's Commission on the
Accident at Three Mile Island
2100 M Street, N.W.
Washington, D.C. 20037

Dear Chairman Kemeny:

During the Commission hearing held on May 30, 1979, a number of questions were asked regarding problems encountered at the Davis-Besse nuclear power plant prior to the accident at Three Mile Island (TMI). Other questions in the same hearing related to documentation of certain events at Davis-Besse, and to our knowledge or awareness of the Davis-Besse problems through receipt of such documentation. I was asked specifically to determine from our corporate records whether we received NRC Inspection Report 50-346/78-06, covering the results of NRC Inspection and Enforcement Divisions inspections conducted at Davis-Besse (Tr. 57-58).

Inspection Report 50-346/78-06 (Enclosure 1) was issued in April, 1978, presenting results of inspections conducted at Davis-Besse in December, 1977 and March, 1978. The report covers a number of subjects, including a loss of pressurizer level indication which was experienced during a transient at Davis-Besse on November 29, 1977. The discussion of loss of pressurizer level indication, due to volumetric contraction of water with reduced temperature ("shrink") following the reactor trip in November, appears on pages 2 and 3 under the section "Further Review of Reactor-Turbine Trip with Loss of Offsite Power".

As we have indicated to the Commission staff in prior correspondence, we did not receive a copy of Inspection Report 50-346/78-06 prior to the May 30 hearing; after the hearing, we obtained a copy from the NRC's Public Document Room in Washington.

We have performed a further review of the official notices that we received or could have received regarding the November 29, 1977 Davis-Besse transient. We regard such official notices to include materials sent by the NRC or by the nuclear steam supply (NSSS) vendor (in this case Babcock & Wilcox) ("B&W"). This review provides considerable insight into both the substance and format of incident reporting available to us prior to the TMI-2 accident.

The existence of the April, 1978 inspection report is mentioned in the May, 1978 issue of the NRC's Monthly Operating Units Status Report (NUREG 0020) (the "Grey Book") on page 2-30 (Enclosure 2). However, the brief summary of

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of this inspection report contained in the Grey Book makes no reference to the November 29, 1977 transient at Davis-Besse. The Davis-Besse transient is indirectly referenced in a letter dated February 2, 1979, from B&W to Met-Ed (Enclosure 3) requesting information on incidents of loss of pressurizer level indication. The B&W letter transmitted to Met-Ed earlier correspondence between B&W and an NRC inspector in which the NRC sought information on events at all B&W plants which resulted in loss of pressurizer level indication due to shrink. In response to B&W's letter, we provided information on two occurrences where pressurizer level indication had been lost at TMI-2 (Enclosure 4), and we sent a representative to attend a B&W meeting on loss of pressurizer level indication held on February 13, 1979, in Lynchburg, Virginia. At the February meeting, B&W presented the results of a 1975 analysis of loss of pressurizer level indication at Arkansas Unit 1. Based on the comments at this meeting, no action was deemed necessary for the TMI plants. To our knowledge, no other utility present at the February B&W meeting took action as a result of that meeting.

Other possible sources of information from B&W have been reviewed, but none have been found that make reference to the November 29, 1977 transient. No mention of it is made in the minutes of B&W Owner's Group meetings. And, while Met-Ed receives weekly Operating Plant Service Bulletins from B&W, the description of the November 29, 1977 incident included in these bulletins (where it is incorrectly identified as taking place on November 30) (see Enclosure 5) makes no reference to loss of pressurizer level; in any event, the brief nature of the discussions included in these bulletins renders them of little value in promoting understanding of complex transients.

The last document I have enclosed with reference to the November 29, 1977 transient is a letter dated March 29, 1979, and distributed by the NRC to Atomic Safety and Licensing Boards and parties to pending NRC licensing proceedings, including Met-Ed (Enclosure 6). This document contains a number of attachments, all of which are internal NRC communications or excerpts thereof, and none of which were received by us in any form prior to their distribution with the March 29 letter to Licensing Boards. Included among those attachments is the January 8, 1979, internal NRC memorandum referred to at the May 30, 1979, Commission hearing. Needless to say, we had no access to the information contained in these documents prior to the TMI-2 accident.

Recognizing the Commission's general interest in the notice that we may have received of problems experienced at other plants and its particular interest in the event experienced at the Davis-Besse plant in September, 1977, we have tracked as well the various reports of that event through and including our receipt of the reports.

Enclosures 7 and 8 are Licensee Event Report NP-32-77-16 and a Supplement thereto ("the Supplement") submitted to the NRC by the Davis-Besse licensee (Toledo-Edison) following the incident that occurred at Davis-Besse on September 24, 1977. As the Licensee Event Report (LER) reflects, that incident involved a trip of the Steam and Feedwater Rupture Control System (SFRCS). This trip of the SFRCS increased primary system pressure causing the pressurizer power relief valve to open. This valve then failed to close resulting in reduction in primary pressure and subsequent safety features actuation. Initial operator response and action was similar to that at TMI-2. Met-Ed never received a copy of the LER or the Supplement. Generally, Met-Ed has not received LERs regarding any plants outside the GPU System.

A copy of this LER might have been received in the GPU Service Corporation's offices in New Jersey through an informal arrangement whereby the Edison Electric Institute collects LERs of member utilities and periodically distributes them to its members for their information. We have been unable to determine, however, from our files or those of EEI whether this particular LER was sent or received.

We have now determined that notice of the September 24, 1977 event at Davis-Besse and the ensuing LER was available to us through several sources. One source is the NRC's Monthly LER PWR Listings, dated December 8, 1977 (Enclosure 9), where information on the Davis-Besse September 24, 1977 event appears in a nine-line summary on page 39. This document was received by Met-Ed and routed through the Licensing Department at Reading and the Training Department at TMI. The Training Department reviewed the report as to the need for possible guidance to the operating staff. No action was deemed necessary.

A second source of information on the September 24 event at Davis-Besse was through the November, 1977 issue of the NRC's Grey Book (Enclosure 10), where a one paragraph description appears on page 2-28. A follow-up item appeared in the December, 1977 volume of the Grey Book on page 2-28 (Enclosure 11). These documents were available in the Met-Ed Generation Library in Reading and in the Training Department at TMI, but the Davis-Besse incident was not identified as requiring action.

A third possible source of information appeared on pp. 2-3 of the December, 1977 issue of a publication titled "Current Events - Power Reactors" from the NRC (Enclosure 12). This discussion, while far more detailed than that contained in the above two NRC monthly reports, did not mention the operator action at Davis-Besse — throttling the high pressure injection pumps — which was an important aspect in our accident. Additionally, the Davis-Besse transient is discussed under a section on valve malfunctions, not operator error. Thus, the organization of the document does not readily direct one's attention to operating procedures. Finally, while Met-Ed was to receive this publication, the issue that appears as Enclosure 12 cannot be located among company records, suggesting that this particular issue may not have been received. This same discussion was reprinted in a commercially circulated publication known as the Atomic Energy Clearing House in its January 9, 1978 issue on pp. 17-18 (Enclosure 13). The Atomic Energy Clearing House is received both in Reading and at TMI; copies at TMI are circulated to certain individuals with directions to take note of specific items. Though this document was circulated to Met-Ed and TMI personnel, the Davis-Besse event was not identified as requiring action at TMI. (We should note that the monthly LER PWR Listings are also typically reprinted in the Clearing House document.)

Finally, a commercially published newsletter from Nuclear Power Experience, Inc. (NPE) discussed the Davis-Besse transient. This document is received monthly in the offices of GPU Service Corporation in New Jersey, and is not circulated to Met-Ed personnel. The July, 1978 issue carried a summary of the Supplement (Enclosure 14), which provided considerable detail on the Davis-Besse event, including the operator's throttling of high pressure injection. Among the dozens of items reported on each monthly NPE issue, some reactor events are identified by the publisher as "Alert" items, meaning that they are believed significant from "outage causing, generic, safety, etc. standpoints" (Enclosure 15). The Davis-Besse transient, which appears as Item 95 on page 4 of the table of contents for the July, 1978 issue, was not identified as an "Alert" item.

With respect to the NSSS vendor, Met-Ed representatives at the B&W Owner's Group meetings have no record of the September, 1977 event being mentioned at those meetings. At one B&W User's Group Meeting, there was cursory mention of the event; the enclosed minutes of such meeting (Enclosure 16) confirm that it was given only limited attention (see page 11). Finally, the September 30, 1977 issue of the B&W Operating Plant Service Bulletin contains a two paragraph report on the event (Enclosure 17).

Other than the enclosed reports, there are no other publications regarding the September 1977 event through which we would have been informed. A table summarizing the information on the September, 1977 event contained in each of the sources available to Met-Ed or GPUSC is attached as Enclosure 18.

The documents enclosed with this letter are intended to provide the Commission with an illustration of our actual notice of information on certain operating problems encountered at other plants. We chose the 1977 Davis-Besse events because of their relationship to the accident at Three Mile Island and the attention these particular events have received.

I do not mean to suggest through this letter that information was not available in addition to the documentation we can now determine we received of these events. All LERs and inspection reports are at least available in the NRC's Public Document Room in Washington. However, it is <u>not more information</u>

on every event which occurs at every nuclear power plant that is needed by utilities. What is needed is an interpretation and prioritization of the vast number of items to which every licensee is now exposed regarding both insignificant and significant problems experienced at other plants.

Our company's review of these materials did not indicate the real significance of the September, 1977 event nor its applicability to TMI operations. Nor did the reviews of the same materials by other utilities or industry consultants cause them to analyze the Davis-Besse events any more closely or imaginatively than we did. In fact, as the record of the hearings before this Commission vividly reveals, only two individuals may have grasped the full nature of the September, 1977 Davis-Besse transient, the indications on plant conditions that the transient provided to the operators, the operator action based on those indications that took place at Davis-Besse, and the potential effect that such operator action could have on the actual, but unrecognized plant conditions. Moreover, these two individuals who may have gained an understanding of the significance of the Davis-Besse event (Mr. Dunn of B&W and Mr. Creswell of NRC) apparently did so after focusing on that transient for an extended period of time; they did not gain their appreciation from the review of reports on that event from the myriad of other event reports available in the literature.

While we plan to intensify our efforts to review all documentation we receive of transients and events that occur at other plants, the potential for real benefits in our review would be greatly enhanced by effective presentation of the information we receive. Met-Ed would welcome the Commission's recommendations in this area of nuclear industry communications.

Sincerely,

RC Arnold

R. C. Arnold

RCA:bas
Enclosures

cc: S. Gorinson, Esq.
Ms. B. Jorgenson

ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

REGION III

Report No. 50-346/78-05

Docket No. 50-346 License No. NPF-3

Licensee: Toledo Edison Company
Edison Plaza
300 Madison Avenue
Toledo, OH 43652

Facility Name: Davis-Besse Nuclear Power Station, Unit 1

Inspection At: Davis-Besse Site, Oak Harbor, OH

Inspection Conducted: December 6-8, 1977 and March 6-8, 1978

Inspector: for J. S. Creswell 4/19/78

Accompanying Personnel: K. A. Connaughton

Approved By: W. S. Little, Chief 4/19/78
Nuclear Support Section

Inspection Summary

Inspection on December 6-8, 1977 and March 6-8, 1978 (Report No. 50-346/78-05)

Areas Inspected: Routine, unannounced inspection of startup testing, natural circulation performance and followup associated with rod drop incident which occurred on December 4, 1977. The inspection involved 35 onsite inspector-hours by one NRC inspector.

Results: Of the three areas inspected, no items of noncompliance were identified in two areas. One item of noncompliance was identified in regard to startup testing. (Infraction - Failure to follow procedures - Paragraph 6)

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DETAILS

1. Persons Contacted

*T. Murray, Station Superintendent
*L. Stalter, Technical Engineer
*W. Green, Administrative Coordinator
J. Lingerfelter, Nuclear and Performance Engineer

The inspector also talked with and interviewed other licensee employees, including members of the technical and operations staffs.

*Denotes those attending the exit interview.

2. Further Review of Reactor-Turbine Trip with Loss of Offsite Power

On November 29, 1977, a reactor trip occurred due to a short in a patch panel used for startup testing.1/ Since the reactor was cooled with the reactor coolant pumps tripped, the licensee desired to use data accumulated during the event to support the conclusion that sufficient natural circulation capability exists. The inspector reviewed charts, data and logs associated with the event in order to ascertain whether the data and conditions under which the event occurred allowed an accurate determination of natural circulation capability.

In the exit interview the inspector stated that based upon his review, the data did not adequately support the requirements of the natural circulation test. Subsequent to this the licensee presented the data to NRR in a meeting held February 7, 1978. By letter from R. S. Boyd to L. E. Roe dated February 16, 1978, NRR informed the licensee that the natural circulation would have to be performed per their commitment in the FSAR. This letter did allow a deferment of 30 days before the test had to be performed.

During the review, the inspector noted that the pressurizer level indication had gone offscale for approximately 5 minutes, and the minimum pressurizer level was not known. The licensee later furnished the inspector with a calculation that the level fell approximately 9 inches below the lower level sensing tap. This

1/ IE Inspection Rpt No. 50-346/77-34.

calculation assumed Loop 1 hot leg temperatures were the same as Loop 2 hot leg temperatures. Actual data for Loop 1 hot leg temperatures were not available. Review of RCS pressure data associated with the reactimeter showed several pressure variations on the order of 50-100 psi during the event. The licensee maintains the indications are erroneous due to faulty instrumentation. Discussions with a reactor operator and review of control room strip charts tend to confirm the licensee's position that the readings were faulty.

No items of noncompliance or deviations were identified.

3. Review of Dropped Rod Bank Event

On December 4, 1977, at 10:33 p.m., safety rod groups 1 and 3 dropped into the core without explanation.[2] Generator output prior to the event was approximately 140 MWe. Power after the rod drop was approximately 50 MWe.

At 9:51 p.m., the licensee had successfully completed auto transfer on "A" and "B" safeguards busses simultaneously. This transfer was accompanied by a computer alarm, "Any Trip Device B/D Tripped."

In addition, the CRD programmer indicated a fault. Electronic technicians were immediately dispatched to determine the cause of the alarms, but they could not determine the source.

The operator recalled seeing safety groups 1 and 3 dropping. When the safety groups dropped, rod groups 6 and 7 withdrew from 26% and 41% withdrawn. Using a rod speed of 30 in/min, it can be inferred that it took the operator about 40 seconds to take manual control of the control rods after the safety groups dropped.

It was determined after the rod drop that Technical Specifications require that the reactor must be placed in Mode 3 in 6 hours. Generator power was decreased to 10 MWe and the turbine output breakers tripped at approximately 11:15 p.m. Rod groups 5, 6, and 7 were then inserted and the reactor taken into the hot shutdown mode and a shutdown margin calculation performed.

After the event, the rod control system vendor was contacted. Personnel from the company reviewed the event and examined the

2/ LER NP 33-77-102, dated 12/27/77.

circuitry, but could not determine the cause for the dropped rods.

No items of noncompliance or deviations were identified.

4. Review of Reactivity Coefficient Determination at Power

The inspector reviewed data and logs associated with Test No. TP 800.05.1 which was performed November 29, 1977. Review of the reactimeter traces revealed reactivity oscillations of a roughly sinusoidal form. The period of the variations was approximately 4 seconds and the amplitude was approximately 2.5 pcm. Reactor power during the test was 40%.*

The licensee attributes the oscillations to fluctuations in steam generator level and to the resulting variations in water temperature and density occurring in the downcomer region of the core. A vendor representative estimated the effect to be less than 1°F variation in T cold temperature. This representative states that similar oscillations have been noted at another of the vendor's sites and that the oscillations diminish as power increases.

Because of the oscillations, the reactivity data must be corrected to remove the oscillating component. Figure 1 shows the behavior of the reactivity trace during the movement of control rod groups 6 and 7. Groups 6 and 7 movement is measured incrementally by reed switch outputs.

During the conduct of the test, the reactor coolant system Tave was lowered 5°F. This resulted in BTU limits being received on the steam generators. Since this was unexpected, the licensee did a setpoint calculation for the BTU limit. This analysis showed that the value programmed into the calculation for reactor coolant flow (67×10^6 lb/hr/loop) was probably in error. The licensee stated that when full power operation is achieved, the setpoint program will be properly calibrated. In order to avoid the BTU limits problem, the licensee issued a temporary procedure change to lower the Tave setpoint 3°F instead of 5°F. Further review of the test will await data reduction and take place in a future inspection. This matter is considered unresolved.

5. Incore Detector System Review

A review of TP 800.24, Incore Detector Testing, and ST 5033.03, Incore Instrument Channel Calibration, was performed on December 7 and 8, 1977. From this review, several questions have arisen.

*Test performed at 75% power with Tave increased 5°F show an almost complete damping of the oscillations.

Section 7.3 of TP 800.24 under "Acceptance Criteria" states, Normalized power corrected SPND value plots for each string are reasonable and consistent with respect to similar symmetrical strings and/or general flux shapes as determined by NPE per 6.8 (5033.03)." There is some uncertainty as to what constitutes "reasonably and consistent", and therefore, whether or not 7.3 (TP 800.24) is definitive enough to be considered an acceptance criteria.

ST 5033.03 was written and is performed to satisfy Technical Specification 4.3.3.2, calling for a channel calibration which does not include the neutron detectors, to be performed at least once per 18 months. ST 5033.03 is essentially a check of the software used to analyze detector signals and a comparison between detectors located in similar symmetrical strings. The "Acceptance Criteria" for this comparison is as described in the previous item. ST 5033.03 is not clearly a channel calibration by definition.

Information concerning the treatment of background detector signals, now deleted from the incore data analysis, was unavailable at the time of this inspection.

Technical information on the aluminum oxide insulated detectors currently in use as part of the incore detector system was unavailable at the time of this inspection.

These items are considered unresolved at this time, pending further investigation.

6. Rod Drop Testing at 40% Power

The inspector interviewed personnel and reviewed records associated with rod drop testing at 40% power. The following sequence of events along with comments was developed.

10/25/77 - Pretest meeting notification

11/26/77 - Pretest checklist completed
Checklist items include:
- Procedure review complete and approved
- Procedure available
- Pretest deficiency list prepared

- Pretest deficiencies resolved per Administrative Directive 1801.04, Resolution of Test Deficiencies

11/27/77 - TP 0800.29, Dropped Control Rod Test, run first time.

Procedure Phase I Prerequisite 6.2.7 states that the axial power shaping rods will be positioned to establish a near axial imbalance of near zero. Actual imbalance was on the order of - 10% at the start of the test.

(Phase II of test not performed on November 27, 1977)

Procedure Step 7.1.1 states to obtain data specified by the Core Power Distribution Procedure, TP 0800.11, Section 7.0. No record was found of Enclosure 1, Prerequisite and Procedure Signoff, for this step. This step was verified as completed.

Procedure Step 7.1.8 states to repeat Step 7.1.1. Again the Enclosure 1 data was not found for this step. This step was verified as completed.

Procedure Step 7.1.9 states to use Enclosure 1 to compare quadrant power tilt manual calculations with those generated by the computer. Enclosure 1 for this test was not found. This step was verified as completed.

Procedure Step 7.1.19 states to calculate minimum DNBR and the maximum LHR using a copy of Enclosure 2. A copy of Enclosure 2 was not found. This step was verified as completed.

The following is an entry in the chronological test log at 1400 hours: "Reviewing the data, we have found that the KW/ft criteria was not met. The problem appears to be in the initial rod position which resulted in approximately 71% WD position of 6/7 when 5-7 was at 0% WD. Ideally, the 6/7 position would have 78% (100% FP insertion limit), but due to small rod worth errors, it was not. The additional 6% on 6/7 will probably be sufficient to modify the flux distribution to meet the KW/ft criteria. The test will be rerun (only the 5-7 rod at 0% WD portion) with an initial rod position of approximately 72% on 6/7 which should put 6/7 at 78% WD when 5-7 is at 0% WD."

Administrative Procedure AD 1801.04, Resolution of Test Deficiencies, defines deficiencies at "A deviation from an authorized requirement document in a component or system identified prior to a test, during a test, or during the review of test results that, were it to remain uncorrected, could adversely affect design and safe operation of the nuclear power plant at any time throughout the expected lifetime of the plant.

The extrapolated value of MLHR to 100% power yielded a value of 20.5 KW/ft. This was in excess of the procedure acceptance criteria of 20.19 KW/ft and the Technical Specifications safety limit basis of 20.4 KW/ft.

Section 7.1 of Administrative Procedure 1801.04 states that if during the analysis of the test data and the review of the test results it is determined that the acceptance criteria were not met, the deficiency shall be documented on Enclosure 1. Enclosure 1 is entitled "Deficiency Report." Not filing a Deficiency Report per AD 1801.04 is considered to be an item of noncompliance with Technical Specification 6.8.1.c.

Not notifying the NRC per the requirements of Technical Specification 6.9.1.8.i after the extrapolated value of MLHR exceeded 20.4 KW/ft is considered to be an unresolved item.

12/9/77 - Phase I of TP 0800.29 was rerun. When the test was performed, the test leader obtained the shift foreman's permission to run the test. The test leader checked off selected steps of the procedure to be performed as follows:

Steps 7.1.1, 7.1.2, 7.1.6, 7.1.7, 7.1.8, 7.1.10, 7.1.11, 7.1.16, 7.1.17, 7.1.18, and 6.1.20.

The steps performed were not verified and dated. Section 6.2, Phase I, Prerequisites, were not verified and dated. Not even a temporary procedure change accompanied the performance of the test to address the procedure modification. Performing the test without an adequately reviewed and approved procedure is an apparent item of noncompliance with Technical Specification 6.8.2.

Again, the test results failed the acceptance criteria in that the maximum linear heat rate extrapolated to 100% power was 21.1 KW/ft.

Again, there was no notification of the NRC per Technical Specification 6.9.1.8.i.

12/17/77- Test Deficiency Report filed by test leader.

Test Deficiency Report states "Extrapolated values of MLHR exceeded fuel melt limit when extrapolated to 100% FP. Values acceptable if extrapolated to trip setpoint of 75% plateau (85% FP)."

The recommended action was to request the reactor vendor to review extrapolation techniques to eliminate unnecessary conservatisms.

The responsible section head did not sign the Deficiency Report until February 17, 1978.

The Deficiency Report was not signed off as noted by the plant superintendent as of the date of the inspection.

On December 15, 1977, the test program manager requested vendor review and comments by issuing a Request for Review and Comments (No. 186). The request states that the enclosed test documentation includes no test deficiencies. A note at the bottom of the request states, however, "This is a preliminary review only. The complete package for review will be forwarded following resolution of test deficiency." On December 16, 1977, the vendor noted in their comments that the extrapolation of linear heat rate to 100% full power does not meet the acceptance criteria. However, an extrapolation to the next overpower trip setpoint (85% of full power) will meet the acceptance criterion and does not represent a safety concern for testing at the 75% plateau.

The vendor stated that they were presently evaluating conservatism in the extrapolation and would provide the resolution to this test deficiency prior to finishing the 75% testing. Until such resolution was provided, the test deficiency was a restraint to increasing the overpower trip setpoint above 85%.

Section II of AD 18091.04 states that the test program manager will maintain a log of the status of all test deficiencies. As of the date of the inspection, the deficiency associated with MLHR had not been logged by the test program manager.

On January 20, 1978, the vendor sent memo SOM No. 335 to TECo personnel which addressed revised hand calculations for Fq, $F_{\Delta H}$ and LHR. Salient points in the memo are as follows:

1. A radial local peak of 1.066 can be used based on our improved core models. (SOM 283 dated May 23, 1977, had described a radial local peak of 1.10)

2. The calculation of LHR should use the densification spike factor for the axial level where the peak occurs and not the factor for the 9 foot level.

Licensee personnel reviewed SOM 335 and requested additional information which was furnished in SOM 336 dated January 31, 197?. This memo explained "The hand calculation of LHR uses conservative factors which add a total of 28% correction to the calculation. Two of these factors (peak to average segment power = 1.04 and the radial local peak - 1.066) total 10.9% and are picked to conservatively to cover any power distribution.

The online computer curve/surface fit routines calculate these factors for the specific power distribution present, and hence, generally calculate numbers less than or equal to the hand calculation numbers.

On the first dropped rod test, the online computer calculated 3.8% as the combined factor of these two items; on the second test the computer calculated 2.4%.' The vendor concluded that the 10.9% factor could be replaced with the aforementioned values to calculate MLHR. The resulting calculation yielded a MLHR of 18.84 KW/ft for the test performed on November 27, 1977, and 19.10 KW/ft for the test performed on December 9, 1977.

SOM 336 also states future calculations of LHR should continued to use the conservative factors listed SOM 335, and if any further limits are exceeded, a detailed analysis of that power distribution will also be required.

7. Review of Quadrant Power Tilting During Rod Drop Testing

Review of online computer calculated tilts at the dropped rod 0% withdrawn condition on November 27, 1977, revealed the following:

Quadrant	WX	XY	YZ	ZW
Incore	13.504	12.474	-9.6816	-16.297
Out-of-Core	1.889	10.233	6.7886	-18.912

Tilts observed at the 50% withdrawn condition on November 27, 1977, were:

Quadrant	WX	XY	YZ	ZW
Incore	8.6494	7.589	-6.2598	-9.9785
Out-of-Core	.5981	6.2744	4.5303	-11.404

A review of the incore versus out-of-core values for tilt reveal significant differences in quadrants WX and YZ. The reason for these differences will be examined in a future inspection. It was also noted that out-of-core channel 8 was reading approximately 10% lower in power than the actual power level. These matters are considered unresolved.

8. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertian whether they are acceptable items, items of noncompliance or deviations. Unresolved items are identified in Paragraphs 4, 5, 6, and 7.

9. Exit Interviews

The inspector met with licensee representatives (denoted in Paragraph 1) on December 8, 1977, to summarized the findings of the inspection. The following items were discussed:

a. Review of the November 29, 1977, event with regards to natural circulation capability. The inspector requested that the test be conducted as per the procedures. (Paragraph 2)

b. Review of the December 4, 1977, safety groups rod drop. (Paragraph 3)

c. Review of reactivity coefficient at power determination. (Paragraph 4)

d. Review of incore system data. (Paragraph 5)

The following commitments were made by the licensee:

a. Faulty instrumentation associated with reactor coolant system pressure monitoring will be investigated and repaired if necessary.

b. An analysis will be provided to determine the minimum pressurizer level attained during the November 29, 1977, event.

c. That an analysis of the November 29, 1977, event with regards to natural circulations capabilities will be forwarded to NRR for review. This analysis will include a detailed description of the conditions surrounding the event.

d. That further monitoring of the rod control system would be explained in the licensee event report concerning the December 4, 1977, event.

On March 8, 1978, an additional exit interview was held with the following item discussed:

The performance of rod drop testing at the 40% power plateau.

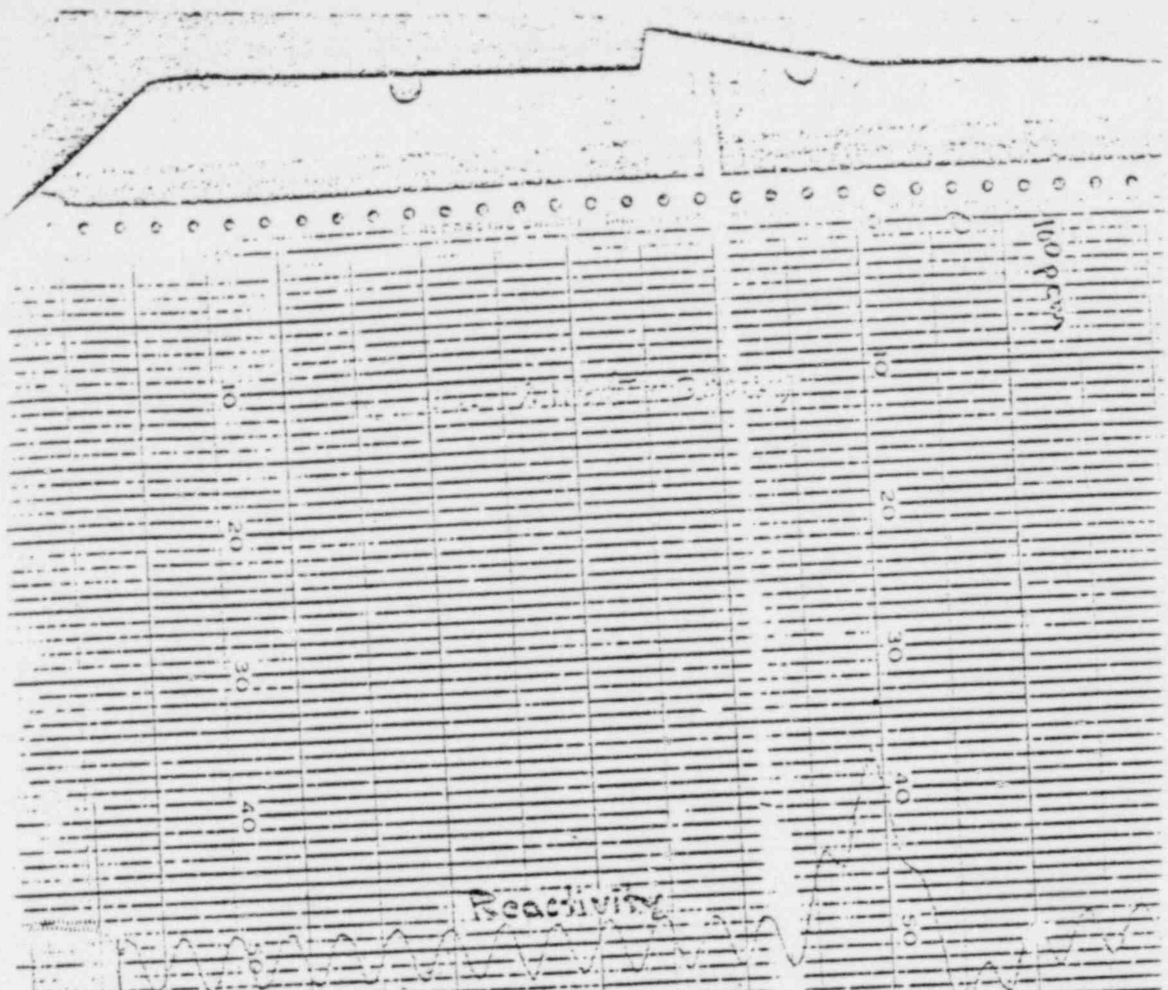
a. Lack of notification of NRC regarding MLHR limits. (Paragraph 6)

b. Lack of filing a Deficiency Report after acceptance criteria was exceeded. (Paragraph 6)

c. Lack of proper review and approval of procedure used during testing which took place on December 9, 1977. (Paragraph 6)

In reply to the item concerning the notification of the NRC, the licensee stated they felt that the axial imbalance experienced during the test represented an overly conservative condition when compared to conditions that would be experienced at 100% power. With regard to filing a Deficiency Report after the first test, the licensee agreed that a mistake was made. The licensee also concurred that management controls over the test run on December 9, 1977, were not as normally exercised and that more emphasis on management controls would be more for exercised for further testing.

Attachment:
Reactivity Chart


100 pcm
Reactivity
Grp 6+7 Position

ENCLOSURE 2

NUREG 0020
VOL. 2 NO. 5
MAY 1978

OPERATING UNITS STATUS REPORT

DATA AS OF 4-30-78

LICENSED OPERATING REACT

DATA FOR DECISIONS

- Department Of Energy
- Nuclear Regulatory Commission

ERRATA SHEETS FOR CORRECTIONS TO HIGHLIGHTS SECTION – MARCH, 1978 DATA (NUREG-0020, VOL. 2, NO. 4, APRIL, 1978)

DAVIS-BESSE 1

NRC POWER RESTRICTIONS: NONE

FACILITY DATA

Description

Location (state/county) (nearest population center)	Ohio/Ottawa 21 miles E of Toledo
Electric Reliability Council	CAPCO
Type of Reactor	PWR
Power Level (MWt)	2772
Design Electrical Rating (MWE Net)	906
Date of Initial Criticality	September 10 1977
Date of Commercial Operation	November 20, 1977
Condenser Cooling Method	Cooling Tower
Condenser Cooling Water Source	Lake Erie

Utility & Contractor Information

Licensee	Toledo Edison Co.
Corporate Address	Edison Plaza, 300 Madison Avenue, Toledo, Ohio 43652
Corporate Contact	J. S. Grant, V.P. Energy Supply (419) 259-5232
Architect/Engineer	Bechtel
Nuclear Steam Supply System	B&W
Constructor	Bechtel

Information

IE Region responsible	III
IE Branch Chief	G. Fiorelli
IE Senior Inspector	R. C. Knop
IE Principal Inspector	T. N. Tambling
Licensing Project Manager	L. Engle
Docket Number	50 346
License Number/Date of Issue	NPF 3, 4/22/77
Public Document Room	IDA Rupp Public Library, 601 Liberty Street, Morris, Illinois 60451

INSPECTION STATUS

ENFORCEMENT STATUS

CONTRARY TO TECHNICAL SPECIFICATION 6.8, PROCEDURES WERE NOT FOLLOWED. (7836 INFRACTION)

2. OTHER SIGNIFICANT ITEMS

A- SYSTEMS AND COMPONENT PROBLEMS:

* MAIN CONDENSER TUBES WILL BE STAKED DURING APRIL 7, 1978, OUTAGE TO ELIMINATE A VIBRATION PROBLEM. (78-0[illegible])

B- FACILITY ITEMS(PLANS AND PROCEDURES):

NONE.

C- MANAGERIAL ITEMS:

NONE.

LAST IE SITE INSPECTION DATE: DECEMBER 6-8, 1977; MARCH 6-10 AND 21-23, 1978

* INSPECTION REPORT NO: 78-06 AND 78-07

3. SUMMARY

INSPECTION SUMMARY

* INSPECTION ON DECEMBER 6-8, 1977 AND MARCH 6-8, (78-06): ROUTINE, UNANNOUNCED INSPECTION OF STARTUP TESTING, NATURAL CIRCULATION PERFORMANCE, AND FOLLOWUP ASSOCIATED WITH ROD DROP INCIDENT WHICH OCCURRED ON DECEMBER 4, 1977. THE INSPECTION INVOLVED 35 INSPECTOR HOURS ONSITE BY ONE NRC INSPECTOR. OF THE THREE AREAS INSPECTED, NO ITEMS OF NONCOMPLIANCE WERE IDENTIFIED IN TWO AREAS. ONE ITEM OF NONCOMPLIANCE WAS IDENTIFIED IN REGARD TO STARTUP TESTING (FAILURE TO FOLLOW PROCEDURES).

* INSPECTION ON MARCH 8-10 AND 21-23, (78-07): ROUTINE, UNANNOUNCED INSPECTION OF MAINTENANCE ACTIVITIES, FOLLOWUP ON CIRCULARS, PART 21 REPORT AND OTHER OPEN ITEMS. THE INSPECTION INVOLVED 49 INSPECTOR HOURS ONSITE BY ONE NRC INSPECTOR. NO ITEMS OF NONCOMPLIANCE OR DEVIATIONS WERE IDENTIFIED.

PLANT STATUS

* LICENSEE INITIATED THREE PUMP OPERATION EARLY APRIL PER RECOMMENDATION OF B&W PENDING RESOLUTION OF BURNABLE POISON ROD PROBLEM DISCOVERED AT CRYSTAL RIVER. PLANNED APRIL OUTAGE POSTPONED UNTIL APRIL 28, 1978, TO INCORPORATE ANY NECESSARY CORRECTIVE ACTION ON THE BURNABLE POISON RODS.

REPORTS RECEIVED FROM LICENSEE

NUMBER	DATE OF EVENT	DATE OF REPORT	TYPE OF REPORT	SUBJECT	PUBLIC ANNOUNCEMENT (Press release date or notify wired)
78-025	03/14/78	03/30/78	30 DAY REPORT	UNIDENTIFIED RCS LEAKAGE GREATER THAN 1 GPM.	NO
	04/14/78	04/17/78	PART 21 REPORT	UNQUALIFIED SCOTCHFIL AND SCOTCH TAPE 33 PLUS	NO
78-026	03/01/78	04/03/78	30 DAY REPORT	POST ACCIDENT RAD MONITOR RE 5029 FAILURE.	NO
78-027	03/16/78	04/12/78	30 DAY REPORT	FAILURE OF AF 3870 AFP 1-1 TO SG 1-1 STOP VALVE TO OPEN.	NO
78-0[illegible]	03/19/78	04/13/78	30 DAY REPORT	SFACS CHANNEL 1, SG 1-1 LEVEL INDICATOR INOPERABLE.	NO
78-029	04/05/78	04/13/78	14 DAY REPORT	BURNABLE POISON RODS.	NO
78-030	03/22/78	04/17/78	30 DAY REPORT	CONTAINMENT RAD MONITORS INOPERABLE.	NO
78-031	03/25/78	04/19/78	30 DAY REPORT	CONTROL ROOM VENTILATION AIR INTAKE CHLORIDE DETECTOR CHANNEL CHECK NOT RECORDED.	NO
78-032	03/28/78	04/19/78	30 DAY REPORT	SFAS CHANNEL 3 INADVERTENTLY PLACED IN TEST TRIP BYPASS.	NO
78-033	03/25/78	04/20/78	30 DAY REPORT	STEAM GENERATOR 1-2 LEVEL LIMIT EXCEEDED.	NO
78-034	03/26/78	04/21/78	30 DAY REPORT	API FOR CONTROL ROD 17 INOPERABLE.	NO

REVIEWED BY OMPA LOEB: M.R. Beebe DATE: 05/30/78

REVIEWED BY NRR DOR: L.B. Engle DATE: 05/31/78

POOR ORIGINAL

ENCLOSURE 3

Babcock & Wilcox

Power Generation Group
P.O. Box 1260, Lynchburg, Va.
Telephone (804) 384-5111

February 2, 1979
TMI-79-16

Mr. J. F. Hilbish
Manager, Licensing
Metropolitan Edison Company
Post Office Box 542
Reading, PA 19603

Subject: Three Mile Island Nuclear Station
Loss of Pressurizer Level Indication

Reference: NRC Letter, J. E. Foster to J. H. Taylor, dated 1/31/79

Dear Mr. Hilbish:

B&W has received the attached request for information concerning the loss of pressurizer level indication at B&W plants from the NRC Region III office. The Region III office is requesting this information based on their feeling that a loss of pressurizer level indication violates Criterion 13 - Instrumentation and Control, which states, "Instrumentation shall be provided to monitor variables and systems over their anticipated range for normal operations, for anticipated operational occurrences, and for accident conditions as appropriate to ensure adequate safety......"

Because of the tight schedule of their request, we would appreciate your prompt response to this request. If you choose to supply the requested information for your plant(s), it would be desirable for the information to be in our hands by February 8, 1979, so we can compile the information and develop the proper strategy.

Present plans call for a strategy meeting on Tuesday, February 13, 1979, in Lynchburg to discuss the concern for utilities that plan to attend the February 14, 1979, meeting.

Please contact us by February 8 if you plan to attend and indicate whether you will investigate past occurrences at your plant.

Very truly yours,

Joel T. Kanin
Service Manager

JTC/mb
Attachment
cc: R. M. Klingaman — E. L. Lawyer
D. F. Miller — J. L. Seelinger
J. D. Logan — G. P. Montgomery
L. C. Rogers
J. L. Smith

The Babcock & Wilcox Company / Established 1867

POOR ORIGINAL

Mr. C. E. Yoder [illegible] January 31, 1979

This information will be of assistance to me during my investigation. If you have any questions or comments concerning this request, please feel free to contact me at (312)858-2660.

Sincerely,

James E. Foster
Investigation Specialist

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION [illegible]
[illegible] ROOSEVELT ROAD
[illegible]

FEB 1 1979

January 31, 1979

Mr. J. H. Taylor
Manager of Licensing
Babcock and Wilcox
P. O. Box 1260
Lynchburg, VA 24505

J. H. Taylor
FEB 2 1979

Dear Sir:

As discussed with Mr. Ray Lukon of your office on January 31, 1979, I am performing an investigation regarding the evaluation of loss of pressurizer level indication at the Davis-Besse facility.

As a part of this investigation, I inquired as to whether there had been any similar events at B&W plants previous to the Davis-Besse event. Mr. Lukon advised that B&W policy does not allow discussion of such information without notification of the respective customer(s) involved, and asked that we send a written request. To fully accommodate this policy, we have re-scheduled our visit to your Lynchburg facility for February 16, 1979, so that notification of your customer(s) of my inquiry can be accomplished.

The information I request to be made available is as follows:

1. What previous experiences of loss of pressurizer level have occurred?
2. The name of the involved utility for those events.
3. The facility where the event(s) were experienced.
4. The dates of occurrence.
5. Whether the NRC was informed of the event.
6. What evaluation of the event was performed.

ENCLOSURE 4

METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603 TELEPHONE 215 – 929-3601

February 8, 1979
GQL 0200

Mr. Joel T. Janis
Service Manager
Babcock & Wilcox
P.O. Box 1260
Lynchburg, Virginia 24505

Dear Mr. Janis:

Three Mile Island Nuclear Station, Unit 2 (TMI-2)
Loss of Pressurizer Level Indication

In response to your letter of February 2, 1979 concerning loss of pressurizer level indication, the following answers to the questions referenced in the NRC letter of January 31, 1979 are provided:

1. Two occurrences have taken place following reactor trips which resulted in loss of pressurizer level indication.

2. Metropolitan Edison Company

3. Three Mile Island, Unit 2

4. a. April 23, 1978

   b. November 7, 1978

5. Yes – a. Inspection Report 78-17, dated May 31, 1978
   LER 78-033/1T, dated May 8, 1978
   Special Report, dated July 24, 1978

   b. Inspection Report 78-23, dated November 30, 1978
   Special Report 78-63/99X, dated January 30, 1979

6. Following each of these two events an evaluation was made to determine the effect on the Reactor Coolant System.

   a. In the April 23, 1978 event, although the pressurizer level indication had gone below zero, evaluations demonstrate that the core remained covered throughout the transient.

POOR ORIGINAL

b. In the November 7, 1978 event, although the pressurizer level indication had gone below zero, a volume of 840 gallons of water remained in the pressurizer. The core remained covered throughout the transient.

No events concerning loss of pressurizer level indication have occurred at Three Mile Island Unit 1 during operation.

As currently scheduled, I will attend the strategy meeting on Tuesday, February 13, 1979 at Lynchburg.

Sincerely,

for J. F. Hilbish
Supervisor-Generation Licensing

JFH:LWH:tas

bcc: R. M. Klingaman
G. P. Miller
J. B. Logan
L. C. Rogers
S. L. Smith
L. L. Lawyer
J. L. Seelinger
C. R. Montgomery
J. G. Herbein

File: 62.0006.0003 (B&W)
63.2627.0000

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ENCLOSURE 5

Operating Plant Services Bulletin
Nuclear Services Publication
Babcock & Wilcox

112.60

Volume 2 Number 48

December [illegible], 1977

OCONEE I

On 11/25/77, NRC approved a new set of technical specifications which allowed operation at 100% full power with all rods out. Power was raised to 100% and has remained at 100% since then. Power tilt is 2.0%.

OCONEE II

Power level was slowly increased to 70% full power on 11/29/77 when a stator cooling water problem forced a power reduction to 25%. The unit was returned to 70% full power on 11/30/77.

After revisions to the air ejector leak rate calculation method, the B OTSG leak rate was determined to be 0.2 gpm which is consistent with chemistry samples. The leak rate seems to hold constant if the power level is increased slowly. On 12/1/77, a 2 gpm gasket leak developed at the pressurizer lower level tap isolation valve and the unit was shut down to make repairs.

OCONEE III

The unit went critical at [illegible] on [illegible]. Physics tests are in progress. Breaker closing is predicted for 12/5/77.

TMI-1

Unit operated at 100% full power during the report period.

ANO-1

The plant was shut down all week for replacement of the reactor building cooling fan. Also during the outage, two RC pump seals were replaced as a preventive maintenance item. The remaining two pump seals will be replaced during the refueling outage. Tubes were plugged on the high pressure heaters and the reheaters to regain the loss of efficiency experienced since they were taken out of service last June. The plant is scheduled to be placed back on line on 12/2/77.

RANCHO SECO NO. 1

The unit operated at 100% full power during the report period.

A turbine casing flange leak has developed and SMUD plans to reduce power to [illegible] and take the turbine off-line to retorque the turbine casing studs. It is estimated that the turbine will be off-line about 6-8 hours.

CRYSTAL RIVER III

Unit operated at or near 100% full power during the report period except for the weekly scheduled condenser tube cleaning.

POOR ORIGINAL

DAVIS-BESSE 1

The unit was undergoing physics testing at 40% full power until tripped by the RPS on 11/30/77. Due to an operator error, all offsite power was lost. No damage occurred, however, the plant will be down until malfunctions in the diesel generator controls are cleared.

INCORE DETECTION ASSEMBLIES

TSB Criteria for replacement of failed incore assemblies is in the process of being forwarded to all B&W operating plants.

Operating Plant Service Bulletin

Nuclear Services Publication

Volume 2 Number 49

December 9, 1977

112.60

OSS
EPK
JNF
JTM

OCONEE I

The unit operated at 100% full power all week. Power tilt is 2.5%. A generator ground has developed and power will be reduced to 15% to allow generator shutdown 12/9/77.

OCONEE II

A valve gasket leak at the pressurizer lower level tap was repaired. The secondary system activity limits prevented startup until 12/7/77. The unit returned to 50% full power on 12/9/77. The OTSG leak is being evaluated as power is being increased at a rate of 1% every eight hours.

OCONEE III

The unit was placed on line at 0450 on 12/4/77. The breaker to breaker outage time was 43 days, 8 hours.

During physics tests, a power tilt was observed. A failure to couple an axial power shaping rod was determined to be the cause of this tilt. The unit was shutdown to couple the APSR and should be back on line 12/10/77.

ANO-1

At about 0100 on 12/3/77 during RC system heatup, RC pump "C" upper seal failed requiring cooldown and replacement. While down, the fourth pump seal was also replaced. All four seals have now been rebuilt. This work exercising a RB sump valve, both the limit switch and torque switch failed on the motor operator which further delayed return to power. Criticality was achieved at 1300 on 12/8/77. After some physics tests, the generator was placed back on the line at 2100 hours on 12/8/77. The unit is presently at 70% full power in the power escalation phase.

TMI-1

Unit operated at 100% full power all week.

RANCHO SECO NO. 1

The unit was reduced to 15% full power and the turbine taken off line at 0700 hours on 12/3/77. The casing studs in the area of the casing flange steam leak were retorqued and the turbine was back on line at 1900 hours on 12/3/77. The unit was held at 85% full power to perform turbine governor valve testing requested by the turbine vendor. During the test, one of the valves stuck in the closed position. The valve was repaired and unit returned to 100% full power at 1750 hours on 12/5/77. The unit operated at 100% full power the remainder of the week.

CRYSTAL RIVER III

Unit operated at or near 100% full power during the report period except for the weekly scheduled condenser tube cleaning and a runback to 15% at the beginning of the report period due to an oscillation problem in the turbine governor valve control system.

DAVIS-BESSE I

Following the trip on 11/30/77, the unit returned to 15% full power on 12/4/77, when two groups of safety rods dropped into the core. The ICS maintained the reactor power level and power output by withdrawing groups 6 and 7. The unit was shutdown after 37 minutes in this configuration because of Tech Spec requirements and to investigate the cause of the drop. Without being able to determine the reason for the dropped rods, the unit was returned to 40% full power on 12/6/77 to complete the testing at this plateau. Transient and trip testing is being delayed somewhat because of the need for power created by the current cold weather.

DOE (FORMERLY ERDA) VIDEO TAPES

For your information, since so many of you have asked, we have attached procurement information on the availability of the DOE refueling outage video tapes.

ENCLOSURE 6

Enclosure

UNITED STATES
NUCLEAR REGULATORY C[illegible]
WASHINGTON, D. C. 20555

March 29, 1979

BOARD NOTIFICATION

Re:	Davis Besse	Docket Nos. 50-500, 50-501
	Erie	Docket Nos. STN 50-580, STN 50-581
	Greene County	Docket No. 50-549
	Midland 1 & 2	Docket No. 50-329 OL, 50-330 OL
	Pebble Springs	Docket Nos. 50-514, 50-515
	Three Mile Island 2	Docket No. 50-320

Ladies and Gentlemen:

Enclosed for the information of the Boards is a recent memorandum relating to certain concerns raised by a reactor inspector in Region III concerning the Davis Besse and Midland units. We are informing the Boards with respect to Davis Besse 2 and 3 and Midland 1 and 2. We are also providing information to the Boards in connection with Erie, Greene County, Pebble Springs, and Three Mile Island 2 since those facilities have similar Babcock & Wilcox reactor units.

Sincerely,

Joseph F. Scinto
Deputy Director, Hearing Division

Enclosure
As Stated

Distribution: (see attached list)

POOR ORIGINAL

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7905160163

Distribution:

Copies of a "Board Notification" letter dated March 29, 1979, signed by Joseph F. Scinto have been served on the following persons. Those whose addresses are at the U.S. Nuclear Regulatory Commission have been served by the NRC internal mail system and others have been served by deposit in the U.S. Mail. One copy has been served on each person even though his or her name appears on more than one service list. In addition to copies served on Atomic Safety and Licensing Board and Atomic Safety and Licensing Appeal Board members identified on the service list, 5 copies of the cover letter for each captioned proceeding and 5 copies in total of the attachment have been provided to the Atomic Safety and Licensing Board Panel, and 1 copy of both cover letter and attachment has been provided to the Atomic Safety and Licensing Appeal Board Panel.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

March 6, 1979

MEMORANDUM FOR: Edward S. Christenbury, Hearing Division Director and Chief Counsel, CELD

FROM: D. B. Vassallo, Assistant Director for Light Water Reactors, Division of Project Management, NRR

SUBJECT: BOARD NOTIFICATION - REACTOR INSPECTOR CONCERNS REGARDING B&W PLANTS (BN-79-10)

The enclosed memorandum from I&E provides information originated by a Reactor Inspector as Board Notification material. Although I&E concluded that the information was not relevant and material the originator still believes that Boards should be informed.

Since we have not yet received I&E's written discussion and evaluation of these matters we have not reviewed the material in any detail. Regardless, however, in accordance with established procedures the information should be provided to appropriate Boards based on the originator's concerns.

The originator recommends that the Davis Besse 2 & 3 and Midland 1 & 2 Boards be informed.

In neither case is the SER Supplement issued but we have no objection to providing the information. In addition, since the concerns appear to apply to B&W plants, we recommend that you also provide the information to the Erie, Greene County, Pebble Springs and TMI-2 Boards.

When we receive the I&E written evaluations we will review them to determine whether additional review should be provided by DSS. In any event, we will follow this up with additional information for the Boards in the near future.

D. Vassallo

D. B. Vassallo, Assistant Director
for Light Water Reactors
Division of Project Management

Enclosure:
As stated

cc: See attached sheet

POOR ORIGINAL

dup

7905160185

cc: H. Denton
E. Case
D. Eisenhut
J. Davis
R. Boyd
V. Stello
R. DeYoung
L. Nichols
B. Grimes
J. Stolz
R. Baer
O. Parr
S. Varga
IE (7)
E. Jordan
D. Thompson

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAR 01 1979

MEMORANDUM FOR: Domenic B. Vassallo, Assistant Director for Light Water Reactors, NRR

FROM: Dudley Thompson, Executive Officer for Operations Support, IE

SUBJECT: INFORMATION FOR BOARD NOTIFICATION - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2

The enclosed information is being forwarded for Board Notification. Your contact on this matter for any additional information is E. L. Jordan, ext. 28180.

Please note that the 2/28/79 cover memorandum, Moseley to Thompson, states that the originator, after being informed of IE Headquarters evaluation, still believes the information should be sent forward to the boards.

We request to be informed of your disposition on this matter.

Dudley Thompson

Dudley Thompson
Executive Officer for
Operations Support, IE

Enclosures:
1. Memo NCMoseley to DThompson dtd 2/28/79
2. Memo JSCreswell to JFStreeter dtd 1/8/79 w/enclosures

cc: N. C. Moseley, ROI w/o encls
E. L. Jordan, ROI w/o encls
J. F. Streeter, RII w/o encls
J. S. Creswell, RII w/o encls
G. C. Gower, XCOS w/encls
IE Files w/encls

POOR ORIGINAL

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FEB 2 8 1979

MEMORANDUM FOR: ~~Dudley~~ Thompson, Executive Officer for Operations Support, IE

FROM: Norman C. Moseley, Director, Division of Reactor Operations Inspection, IE

SUBJECT: NOTIFICATION OF LICENSING BOARDS (AITS F30468H2)

Enclosed are six items sent in by Region III for forwarding to sitting Licensing Boards for cases involving Babcock and Wilcox as the Nuclear Steam System Supplier. Our preliminary evaluation indicates these items do not appear to be new issues or to put a different light on the issues and therefore, in our opinion, do not meet the intended criteria for Board notification.

The originator was informed, via telephone, of this determination on February 27, 1979. His position was that our evaluation did not provide any information that he did not already have and his concern was whether or not these items had been considered and resolved on a generic basis for all B&W plants. Because of this he still believed the items should be sent to the Licensing Boards. IE Manual Chapter 1530 requires that if, after a negative determination, the originator continues to believe that the information should be submitted to the Board(s), the information will be submitted. We therefore request the enclosed items be sent to the appropriate Licensing Boards.

We will provide a written discussion and evaluation of each item within seven (7) days of the date of this memorandum.

for Norman C. Moseley
Director
Division of Reactor
Operations Inspection, IE

Enclosure:
Memorandum Creswell to Streeter
dated January 8, 1979

cc w/o encl:
S. E. Bryan
E. L. Jordan
D. Kirkpatrick
J. C. Stone
G. C. Gower
R. F. Heishman, RIII

POOR ORIGINAL

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NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

January 8, 1979

Docket No. 50-500/501
50-329/330

MEMORANDUM FOR: J. F. Streeter, Chief, Nuclear Support Section 1

FROM: J. S. Creswell, Reactor Inspector

SUBJECT: CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2

During the course of my inspections at Davis-Besse, certain issues have come to my attention which I am submitting for consideration for forwarding to the Atomic Safety and Licensing Board which has proceedings pending for the aforementioned facilities. This submittal is made pursuant to Regional Procedure 1530A (November 16, 1978), step 3 and information supplied to me per step 1. The issues for consideration are:

1. During a recent inspection at Davis-Besse Unit 1 information has been attained which indicates that at certain conditions of reactor coolant viscosity (as a function of temperature) core lifting may occur. The licensee informed the inspector that this issue involves other B&W facilities. The Davis-Besse FSAR states in Section 4.4.2.7:

   > The hydraulic force on the fuel assembly receiving the most flow is shown as a function of system flow in Figure 4-39. Additional forces acting on the fuel assembly are the assembly weight and a hold down spring force, which resulted in a net downward force at all times during normal station operation.

   The licensee states that there is a 500°F interlock for the starting of the fourth reactor coolant pump. However, no Technical Specification requires that the pump be started at or above this temperature. A concern regarding this matter would be if assemblies moved upward into a position such that control rod movement would be hindered.

2. Inspection Report 50-346/78-06, paragraph 4, reported reactivity - power oscillations in the Davis-Besse core. These oscillations have also occurred at Oconee and are attributed to steam generator level oscillations. B&W report BAW-10027 states in A9.2:

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The OTSG laboratory model test results indicated that periodic oscillations in steam pressure, steam flow, and steam generator primary outlet temperatures could occur under certain conditions.

It was shown that the oscillations were of the type associated with the relationships between feedwater heating chamber pressure drop and tube nest pressure drop, which are eliminated or reduced to levels of no consequence (no feedback to reactor system) by adjustment of the tube nest inlet resistance. As a result of the tests, an adjustable orifice has been installed in the downcomer section of the steam generators to provide for adjustment of the tube nest inlet resistance and to provide the means for elimination of oscillations if they should develop during the operating lifetime of the generators. The initial orifice setting is chosen conservatively to minimize the need for further adjustment during the startup test program.

We also note that the effect on the incore detector system for monitoring core parameters during the oscillations is not clear.

3. Inspection and Enforcement Report 50-346/78-06 documented that pressurizer level had gone offscale for approximately five minutes during the November 29, 1977 loss of offsite power event. There are some indications that other B&W plants may have problems maintaining pressurizer level indications during transients. In addition, under certain conditions such as loss of feedwater at 100% power with the reactor coolant pumps running the pressurizer may void completely. A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1. Because of pressurizer level maintenance problems the sizing of the pressurizer may require further review.

Also noted during the event was the fact that Tcold went offscale (less than 520°F). In addition, it was noted that the makeup flow monitoring is limited to less than 160 gpm and that makeup flow may be substantially greater than this value. This information should be examined in light of the requirements of GDC 13.

4. A memo from B&W regarding control rod drive system trip breaker maintenance is attached as Enclosure 2. This memo should be evaluated in terms of shutdown margin maintenance and ATWS considerations particularly in light of large positive moderator coefficients allowable with B&W facilities.

POOR ORIGINAL

5. Inspection and Enforcement Report 50-346/78-17, paragraph 6 refers to inspection findings regarding the capability of the incore detector system to determine worst case thermal conditions. The reactor can be operated per the Technical Specifications with the center incore string out of service. If the peak power location is in the center of the core (this has been the case at Davis-Besse), factors are not applied to conservatively monitor values such as F_Q and F delta H.

6. Enclosure 3 describes an event that occurred at a B&W facility which resulted in a severe thermal transient and extreme difficulty in controlling the plant. The aforementioned facilities should be reviewed in light of this information for possible safety implications.

J. S. Creswell
Reactor Inspector

Enclosures: As stated

cc w/o enclosures:
G. Fiorelli
R. C. Knop
T. N. Tambling

TOLEDO EDISON

LOWELL E. ROE
Vice President
Facilities Development
(419) 259-5242

Docket No. 50-346

License No. NPF-3

Serial No. 4?5

December 22, 1978

Director of Nuclear Reactor Regulation
Attention: Mr. Robert W. Reid, Chief
Operating Reactors Branch No. 4
Division of Operating Reactors
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Reid:

In response to the December 20, 1978 telephone conversation between your Mr. Guy Vissing and our Mr. E. C. Novak, and the December 20, 1978 telephone conversation between NRC Region III personnel (C. Fiorelli, R. Knop, T. Tambling and J. Streeter) and our Mr. E. C. Novak, attached is an additional safety evaluation supporting continued operation of Davis-Besse Nuclear Power Station Unit 1. This additional safety evaluation supplements the analysis we provided to you by our letter dated December 11, 1978, Serial No. 47?. The attached safety evaluation analyzes the transient resulting from the operator not controlling steam generator level at 35 inches in accordance with current operating procedures.

Yours very truly,

Lowell E. Roe

LER:GRD

Enclosure

bj e/7

POOR ORIGINAL

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[illegible]
December 11, 1978

Additional Safety Evaluation
of Transient Resulting from
Inability of Operator to Control
Steam Generator Level at 35 Inches

I. INTRODUCTION

The Davis-Besse Unit 1 Steam and Feedwater Line Rupture Control System (SFRCS) design objectives are to prevent the release of high energy steam, to automatically start auxiliary feedwater (AFW), and to provide adequate AFW, via essential steam generator level control, to remove decay heat during anticipated and design basis events when AFW is required. Table 1 correlates the station variables and accident conditions for which AFW actuation is required. For all actuation signals, the SFRCS initiates and controls AFW addition automatically to maintain a 120" level (96" indicated on the startup range instrumentation) in the steam generators.

The recent natural circulation test at Davis-Besse 1 (TP800.04) demonstrated that a 35-inch (indicated) steam generator level of AFW provides adequate natural circulation for decay heat removal.

The auto essential SG level control setpoint of 120-inches (96-inch-indicated) is thus in excess of minimum SG level requirements.

Operating procedures requiring manual control of steam generator level at 35-inches on the startup range level indicators following non-LOCA events were developed and used at Davis-Besse Unit 1 pending installation of permanent design changes to the SFRCS. Margin in maintenance of indicated pressurizer level and assurance of adequate natural circulation capability will exist through operator intervention during conditions where AFW is required.

Inability of the operator to comply with the present operating procedures will possibly result in a momentary loss of pressurizer level and/or level indication under certain conditions, but will not produce consequences which are non-reversible or detrimental to safe operation of Davis-Besse Unit 1.

II. DISCUSSION

The following section is divided into three segments: Relationship with Events Presented in the Davis-Besse Unit 1 FSAR, Loss of Offsite Power, and Loss of Feedwater.

A. Relationship with events presented in the FSAR

Addition of auxiliary feedwater at rates considerably greater than the decay heat generation rate will result in overcooling of the reactor coolant, contraction and a reduction of pressurizer level. This sequence of events is typical of several transients presented in the FSAR which have been submitted to the NRC and approved as a part of the licensing process. Overcooling transients can be caused by a variety of circumstances, failures, combinations of operating equipment, and improper operator interactions. From a practical viewpoint each single discoverable possible transient cannot be analyzed and presented as a part of the FSAR analysis, but a broad variety of transients have been selected. This specific transient fits within that broad category. Each of the FSAR transients has been demonstrated to produce acceptable results.

Overcooling transients resulting from a variety of causes are described in Section 15.2.10 "Excessive Heat Removal due to Feedwater Malfunctions". This section describes a transient resulting from excessive main feedwater addition, which is similar to the specific transient of increased level addition by auxiliary feedwater. Further information is presented in response to questions 15.2.15 and 15.2.16.

The steam line break (see FSAR sections 15.4.4, 15.4.8, 15.4.1) is the most severe overcooling transient in that the reactor coolant system is decreased 50°F in average core temperature over a 30 second time period.

This is compared with the cooldown in question, which takes a much longer time to achieve a similar temperature drop and system conditions. During the steam line break, RC system pressure is reduced from 2200 psia to about 900 psi as system temperature is driven toward equilibrium with the unaffected (pressurized) steam generator attaining saturation temperature of about 530°F. The pressurizer is near empty at about 20 seconds and thereafter loses its influence on the system, thus permitting the upper elevations of the reactor coolant loop to approach saturation as cooldown continues toward 530°F. High pressure injection (HPI) pumps are actuated on low RC pressure such that pressurizer level will be restored. As shown in Figures 15.4.4-1 and 15.4.4-2 of the Davis-Besse Unit 1 FSAR, the rapid cooldown of RCS after reactor trip is limited by the pressure maintained in the pressurized steam generator in much the same fashion as anticipated for events such as the event of concern. As the RCS approaches saturation, core cooling is not impeded. Minimum DNBR>1.3 occurs just before reactor trip and subsequently increases with substantial margin throughout the remainder of the cooldown.

The close relationship of the auxiliary feedwater level increase as an overcooling transient with these similar overcooling transients allows us to draw the conclusion that no unreviewed safety question exists. To show a comparison to the detailed analyses reported in the FSAR, we have performed conservative bounding analyses of two representative cases.

B. <u>Loss of Feedwater and Loss of Offsite Power</u>

We have analyzed two transients resulting from auxiliary feedwater addition and establishment of SG level above the operating procedure 35" limit. The two transients examined are a loss of offsite power (reactor coolant pumps stop, makeup stops, main feedwater stops) and a loss of feedwater (reactor coolant pumps continue, makeup continues).

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Of these two transients the loss of feedwater results in the greater volumetric coolant contraction, because the forced coolant flow (RC Pumps operating) causes a faster rate of heat rejection to the steam generator.

1. Loss of Offsite Power

Preliminary calculations for a reactor trip following a loss of offsite power show that the pressurizer loses indication but does not empty. The assumptions used to derive this result included full runout auxiliary feedwater flow (~2400 gpm) resulting in a fill time to 120" of about 4 minutes. No net mass change to the primary coolant (no makeup, no letdown) was considered, even though the makeup controls would respond to decreasing pressurizer level by increasing the net input to above 200 gpm. At the termination of the transient the pressurizer level is slightly above the outlet into the surge line. Reactor coolant pressure reaches about 1600 psi and high pressure injection may be automatically initiated.

Although the net makeup was not considered, it would in fact cause the pressurizer to refill to the normal level. At the same time compression of the steam would cause a partial repressurization of the system ensuring that the coolant remains subcooled. This transient presents no safety concerns.

2. Loss of Feedwater

This transient has a greater reactor coolant contraction than the loss of offsite power case, resulting in emptying of the pressurizer. Consequently it will be described in greater detail.

A brief summary of the events is:

• Reactor trip	Time = 0
• Makeup control valve opens wide admitting full makeup to reactor coolant system	Time = 0^+
• AFW initiated	Time $\approx$ 40 sec
• Pressurizer empties; RC system pressure slightly greater than 1600 psi	Time $\approx$ 2 min
• HPI initiated by SFAS; makeup isolated	Time $\approx$ 2^+ min
• Steam generator level = 10 ft; voids exist in reactor coolant	Time $\approx$ 4 min
• HPI inflow replaces volume occupied by voids; pressurizer level begins to be restored	Time $\approx$ 7-8 min

The major concerns that evolve from this transient are the disposition of the steam voids and the approach to DNB. Both of the concerns are ameliorated by the reactor coolant pumps.

Steam voids will not collect in reactor coolant piping and no flow blockage will occur because of dispersal and mixing by the forced flow. DNB acceptance criterion limit will be met because the [illegible] output of the core is at the decay heat level and all reactor pumps are operating, maintaining core heat removal. We conclude that no safety problem exists.

TABLE 1: STEAM AND FEEDWATER LINE RUPTURE CONTROL SYSTEM (SFRCS)ACTUATION PARAMETERS

Actuation Parameter Station Variables	Setpoint	Accident
1. Low Steam Line Pressure	$<$ 591.6 psig[1,2]	Steam Line Break Feedwater Line Break
2. Low SG Level	$\leq$ 17 inches[1]	Loss of F/W
3. SG Pressure Minus Main Feedwater Line Pressure	$>$ 197.6 psi[1]	FWLB, LOMFW
4. Loss of All RC Pumps[3]		Loss of Off-Site Power

NOTES:

1. When actuated, SFRCS closes both main steam isolation valves, closes both main FW control and stop valves, initiates AFW and controls AFW to maintain a 120 inch level in the SGs.

2. Alignment of AFW to a pressurized SG is provided for steam and feedwater line breaks.

3. AFW initiation but steam and feedwater line isolation does not occur.

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[illegible]

Introduction:

The following bounding analysis conservatively predicts the events occurring within the primary reactor coolant system and reactor following a loss of main feedwater from 100% power for the Davis-Besse Unit 1. Auxiliary feedwater control has been assumed at 10 feet within both steam generators.

Results:

Because of the conservative, bounding, nature of this calculation, the overcooling of the primary system due to auxiliary feedwater injection causes a contraction of coolant volume sufficient to create steam within the primary system. The steam is shown to be uniformly distributed within the RCS and the void fraction is 4%. The reactor coolant pumps maintain full capability. The DNB ratio is shown to exceed 2.0 and no return to criticality potential exists. Thus, during the course of the incident, no core problems develop. Further, following the time of maximum contraction, the system recovers to full pressure, pressurizer function is regained and the reactor coolant returns to a subcooled water configuration without operator action.

Analysis:

The following assumptions have been made to assure the bounding nature of the results:

Reactor Power:

100% until boiling stops in the steam generators; 0% after that time. This assumption is conservative as core heat would compensate for the cooling caused by the auxiliary feedwater.

Initial Coolant Inventories Water:

RCS = 11290 ft^3

Pressurizer = 864 ft^3

These assumptions are nominal operating values.

Initial Temperatures:

The whole system is taken to be at $T_{average} = 582^{\circ}F$.

This assumption is a reasonable average.

Initial System Mass: ~ 500,000 lbm

The mass is figured from the temperature and volumes above.

Makeup System:

No credit is taken for additional makeup flow which will occur as the pressurizer loses level. (In all likelihood, the makeup system will contribute approximately 200 ft^3 extra liquid volume).

Local Power (kw/ft): 18.4 kw/ft

This value is taken as the maximum allowed by Technical Specifications.

Secondary Side Volume At 10 Foot Level

711 ft^3 per generator, actual volume.

Auxiliary Feedwater Flow:

166.5 ft^3/min. per generator actual value.

Auxiliary Feedwater Enthalpy:

8 Btu/lbm lower bound for maximum cooling.

With the initiating event, loss of main feedwater, the reactor coolant system pressure will start to rise. Reactor trip will occur on high RCS pressure. Following trip, the RCS pressure will fall because core power has been reduced and boiling of residual main feedwater or auxiliary feedwater is occurring in the steam generators. These events are almost identical to those which occur in a main feed line break and are analyzed in detail in Section 15.2.8 of the FSAR.

In short order, the system will return to its initial configuration but, because the auxiliary feedwater heat absorption rate exceeds the decay heat generation rate, the RCS continues to depressurize. During this phase, residual main feedwater and injected auxiliary feedwater will be boiled and vented through the steam generator safety relief valves. The primary system average temperature will fall to the saturation temperature of water at the safety valve set pressure. At this time, primary and secondary conditions are expected to be approximately as follows:

	Primary	Secondary
Pressure	1800 psia	980 psia
Temperature	542 F	542 F
Mass	503344 lbm	0 lbm
Liquid Volume in Press.	400 ft^3	N.A.
Time into Transient	$\sim$ 2 min.	$\sim$ 2 min.

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It is conservative to assume complete cooling of the secondary side water and complete equilibrium between primary and secondary sides, as these assumptions lead to the maximum follow on injection of auxiliary feedwater and therefore, maximum contraction. RCS pressure is held up by the steam bubble in the pressurizer.

The time has been estimated by calculating the necessary energy loss by the primary system from its initial conditions, the mass of auxiliary feedwater required to remove this energy and then dividing by the auxiliary feedwater flow rate.

$$\text{time} \simeq \frac{(586 - 542)\ 503344}{(1194-8)\ \ 383\ \ 62} \simeq 54 \text{ sec.}$$

Six seconds was used to estimate the initial pressurization portion of the transient.

In performing the remainder of the evaluation 10 feet of cooled (40 F) auxiliary feedwater is placed in each steam generator and the thermal equilibrium condition calculated. Because after a 10 foot level is obtained this auxiliary feedwater flow stops, this condition represents the maximum contraction possible. The state variables resulting are:

	Primary	Secondary
Pressure	560 psia	560 psia
Temperature	478 F	478 F
Enthalpy of Water	462 Btu/lbm	462 Btu/lbm
Specific Volume	.020 ft^3/lbm	.020 ft^3/lbm

From the specific volume, the primary liquid volume can be calculated:

$Vol = MV_f = 10052\ ft^3$

As 10052 is smaller than the RCS minus pressurizer volume, the remaining volume must be filled with steam.

$V_{st} = 10426 - 10552 = 374\ ft^3 \approx 400\ ft^3$

400 ft^3 corresponds to a system void fraction of 3.8% $\simeq$ 4%, and as will be shown later, is of no consequence as far as core heating or system performance is concerned. This steam volume is larger than actually expected for two reasons: 1) some temperature difference would always exist between the primary and secondary systems, and 2) the effect of core decay heat has been ignored. Both of these would increase the primary side liquid temperature, thus increasing its volume and reducing the steam volume.

Following this state of maximum contraction, no further heat is removed from the RCS via the secondary side until the RCS rises in temperature due to decay heating; this will expand the liquid volume, compress the steam and repressurize the RCS. As no mass can be lost from the secondary

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[illegible] the first [illegible] stage will end at a primary system pressure, temperature, and liquid volume of [illegible] psia, [illegible] F, 10832 ft³. Subtracting 10426 from 10832 shows that about 400 ft³ of fluid has been forced back into the pressurizer. Pressurizer function would then be restored (if not directly, then, by either the makeup or HPI system), the RCS subcooled and the transient ended.

Several questions exist about the transient:

I. How is the 400 ft³ dispersed within the primary system and can that volume collect in one location? From the auxiliary feedwater flow rate, over 4 minutes are required to fill the generators. As the pressurizer has 400 ft³ in it at 980 psia and the RCS has 400 ft³ in it at maximum contraction, approximately 2 minutes are used to eject steam from the pressurizer to the RCS. Because this steam will be superheated when it enters the RCS it will first desuperheat and then condense at a rate governed by its expanding pressure compared to the contraction of the liquid coolant. In the time of 2 minutes the reactor coolant will have made about 8 complete circles of the primary system and the steam can be considered well mixed. As the flow velocity in the RCS will remain normal, about 25 ft/sec, steam water separation will tend not to occur. Some limited steam accumulation may occur in the upper head of the reactor vessel as in that specific location of the RCS, velocity is low.

II. How well will the pumps work? Experiments performed on steam carry over capability show that for void fractions up to 10% no loss of pump capability is observed. This is documented in Figure 5-47 of BAW-10104, "B&W's ECCS Evaluation Report With Specific Application to 177 FA Class Plants With Lower Loop Arrangement." Actually pump capability increases for the first 3% of void introduced into the system.

III. Will any return to power be encountered because of the low RCS temperature? A return to power can occur for a non-borated core at 490F. This temperature includes the assumption of the most reactive rod stuck out of the core; if that rod were taken as inserted the critical temperature would fall to at or below 400F. Although no credit was taken for HPI in calculating the RC steam volume below 1600 psia, the HPI will be injecting borated water and, therefore, preventing any return to power condition. If the primary system were to stabilize at 1600 psia and thus prevent the HPI from providing boron the RCS temperature would be at least 511F and, therefore, no return to power would be expected.

IV. Will DNB be encountered in the core? The maximum contraction condition is again:

P = 560 psia
T = 479F
a = 4%,

[illegible] at [illegible] 5 [illegible] very early within 10 seconds of [illegible] feedwater [illegible]. At this time, the decay heat rate is less than 3.2% using ANS + 20% (the LOCA evaluation curve). As low pressure and high void and high power are conservative bounds a DNB evaluation was performed at:

P = 500 psia
T = corresponding saturated value
[illegible] = 8%
power = 10%
W = full volumetric flow.

The resultant DNBR was >15 in the hottest channel with maximum design conditions assumed and well within acceptable values.

V. Will any steam remain trapped in the primary system? Some may be trapped for a short period of time in the upper head of the reactor vessel but this will be of no consequence and will eventually be condensed by thermal conduction through the interfacing water.

Conclusion

The maximum contraction of the RCS water has been calculated taking no credit for mitigating systems (makeup flow, HPI) and no credit for decay heating. No adverse consequences of the transient have been shown and, therefore, this transient poses no concerns to the safe operation of the plant.

IV. CONCLUSIONS

For SFRCS actuation and fill of the steam generators to the auto-essential level control point of 120" without operator action:

- No unreviewed safety question exists
- The loss of offsite power transient will not cause the pressurizer to drain although a loss of pressurizer indicated level will occur.
- The loss of feedwater transient may result in pressurize emptying, however acceptance criteria for DNB will be met. Steam bubbles which exist in the reactor coolant for a short time will be collapsed by HPI injection. Pressurizer refilling by HPI will occur.
- No return to power will result in the long term.

P.O. Box 1260, Lynchburg, Va. 24505
Telephone (804) 384-5111

June 12, 1979

SOM #382 620-0014
12B-3 T3.3.1
SIP #14/289

Mr. T. D. Murray, Station Superintendent
Davis-Besse Nuclear Power Station
5501 North State Route #2
Oak Harbor, Ohio 43449

Subject: CRDCS Trip Breaker Maintenance

Dear Terry:

In the past, some of our plants have experienced problems with CRDCS Trip Breakers. The problems have been traced to lack of preventive maintenance. B&W suggests that a planned, carefully executed, maintenance program be established using the maintenance program outlined in the Diamond Power CRDC System Vendor Manual. Particular attention should be directed to proper cycling, cleaning, and lubrication of the breakers.

B&W further recommends that this program be scheduled at a minimum frequency of every refueling cycle and more frequently for plants during startup, when the equipment is subject to adverse environmental conditions.

Our concern is that if proper maintenance is not accomplished, additional failures will occur resulting in an NRC demand for diverse qualified trip breakers. Also, we need to prevent all failures we can to reduce the number of lost capacity days.

If we can be of further assistance, please advise.

Yours truly,

F. R. Faist
Site Operations Manager

FRF:IDG:mlf
cc: W. H. Spangler
R. C. Luken
R. L. Pittman
D. A. Lee
J. S. Grant, TECo
E. C. Novak, TECo
C. R. Domeck, TECo
J. G. Evans, TECo
B. R. Beyer, TECo
J. D. Lenardson, TECo
R. E. Blanchong, TECo
J. C. Buck, TECo

Babcock & Wilcox

Power Generation Group

P.O. Box 1260, Lynchburg, Va. 24505

Telephone: (804) 384-5111

August 9, 1978

[illegible]

[illegible]

SIP [illegible]

Mr. T. D. Murray, Station Superintendent
Davis-Besse Nuclear Power Station
5501 North State Route #2
Oak Harbor, Ohio 43449

Subject: SMUD Rapid Cooldown Transient

Dear Terry:

On March 20, 1978, Rancho Seco experienced a severe thermal transient initiated by the loss of electrical power to a substantial portion of the Non-Nuclear Instrumentation (NNI). The loss of power directly caused the loss of Control Room indication of many plant parameters, the loss of input of these parameters to the plant computer, and erroneous input signals (mid-range, zero, or otherwise incorrect) to the Integrated Control System (ICS).

The plant response was not the usual transient in that the ICS responded to the erroneous input signals rather than actual plant conditions, and resulted in a Reactor Protection System (RPS) trip on high pressure. Subsequent to the Reactor Trip, the erroneous signals to the ICS contributed to the rapid cooldown of the RCS. Plant operators had extreme difficulty in determining the true status of some of the plant parameters and in controlling the plant because of the erroneous indications in the Control Room.

An investigation of the events following this loss of power points out a need for a close look at operator training and emergency operating procedures for any loss of NNI power (or portion thereof). The following recommendations are made to assist your staff in a review of training and procedures to assure proper operator action for events of this nature.

1. Operators should be trained to recognize a loss of power to all or a majority of their NNI (e.g. indicators fail to mid-range, automatic or manual transfer to alternate instrument strings brings no response). The loss of power is emphasized here rather than the failure of any one instrument or control signal which are adequately covered in current simulator training courses.

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2. Given that the operator can determine that electrical power has been lost to all or part of the NNI, he should know the location of the power supply breakers, and have a procedure available to quickly regain power.

3. If the fault cannot be cleared (i.e. the breakers to the power supplies reopen), the operator should have a list of alternate instrumentation available to him, and he should be thoroughly trained in its use. Examples are:

   a. ESFAS panels
   b. RPS panels
   c. ECI (Essential Controls and Instrumentation)
   d. SRCI (Safety Related Controls and Instrumentation)
   e. Remote shutdown panels
   f. Local gages
   g. Plant computer

4. Recognizing that no procedure can cover all possible combinations of NNI failures, the operator's response should be keyed to certain variables. If the operator realizes that he has an instrumentation problem (as opposed to a LOCA or steam line break, for example), he can limit the transient by controlling a few critical variables:

   a. Pressurizer Level (via HPI or normal Makeup Pumps)
   b. RCS pressure (via Pressurizer heaters, spray, E/M relief valves, etc.)
   c. Steam Generator level (via feed flow, feedwater valves, etc.)
   d. Steam Generator pressure (via turbine bypass system)

   The pressurizer level and RCS pressure assure that the Reactor Coolant System is filled; the Steam Generator level and pressure assure adequate decay heat removal.

Attachments 1 and 2 are provided to give a brief description of the events following this loss of NNI power at Rancho Seco. As can be seen by this transient, prompt precise operator action and the ability to recognize a loss of NNI power are critical factors in limiting the severity of a transient such as this.

If you have any questions or comments, please advise.

Yours truly,

Ivan D. Green
Site Operations Manager

IDG:TFB:mlf
encl.
cc: See attached sheet.

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[illegible]

(Revision 1, 5/25/79)

EVENT

[illegible]:08 - Lost NNI power supply cabinets [illegible]

- This caused a loss of valid signals to the ICS. BTU limits ran back feedwater, resulting in a partial loss of feedwater (actual Rx power was 72%).

- Probable opening of "B" turbine bypass valves to the condenser (timing uncertain).

[illegible]:44 - Reactor trip on high pressure, turbine trip on interlock.

- Pressurizer code relief setting was known to be low (approximately 2225 psig). The electromatic relief was isolated due to previous leakage problems. The data indicates primary pressure went ≈2400 psig => code relief valve lifted.

- ICS closes main control and start-up feed valves and drive main feed pumps to minimum speed following trip.

- Decay heat and RC pumps energy removal accomplished through generators by inventory boil off and the addition of main feedwater.

[illegible]:15 - Pressurizer code relief valve reseats at approximately 2100 psig.

- Operator starts HPI pump "B".

[illegible]:22 - Operator stops HPI pump "B".

[illegible] - OTSG "B" pressure reaches 435 psig set-point of Steam Line Failure Logic.

- OTSG "B" goes dry.

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4:?? - RC pressure ≈1900 psi

7:16 - SFAS actuation at 1600 psig

This starts HPI, LPI and initiates emergency feed. The emergency FW pump is started and the bypass emergency FW valves are opened to full open position. The system makes no automatic attempt to control steam generator water level.

?0 - RC pressure at 1475 psig. It starts to recover from this point due to HPI. T_{ave} = 523°F.

?3:56 - "A" HPI pump secured.

46:09 - LPI secured.

47 - "A" HPI initiated. From this point on, the operator started and stopped HPI pumps as necessary to maintain pressurizer level.

50 - Steam Line Failure Logic closes ICS-controlled start-up feed valves to each OTSG when the corresponding OTSG pressure falls below 435 psig.

51:25 - Secured RCP-D (T_{ave} ≈435°F)
This reduced #RCP's to three

57:27 - OTSG "A" water level - 399.7"

Speculate that ≈2 ft. of tubes are not flooded (at top) due to steam line arrangement.

?:00:00 - Hourly computer log print-out
Steam temp. 380°F (OTSG "B")
Steam pressure 171 psig (OTSG "B")

Assuming $T_{ave} = T_{sat} \Rightarrow T_{ave} = 380°F$

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- Power restored to NNI cabinets 5,6,17

$T_{ave} = 285^{\circ}F$

RCS Pressure ≈2000 psig

Both OTSG full level ranges pegged high

Operator begins to reduce RC pressure using pressurizer spray.

ICS closes turbine bypass valves to condenser.

Operator stops emergency FW flow.

Operator stops main FW pumps.

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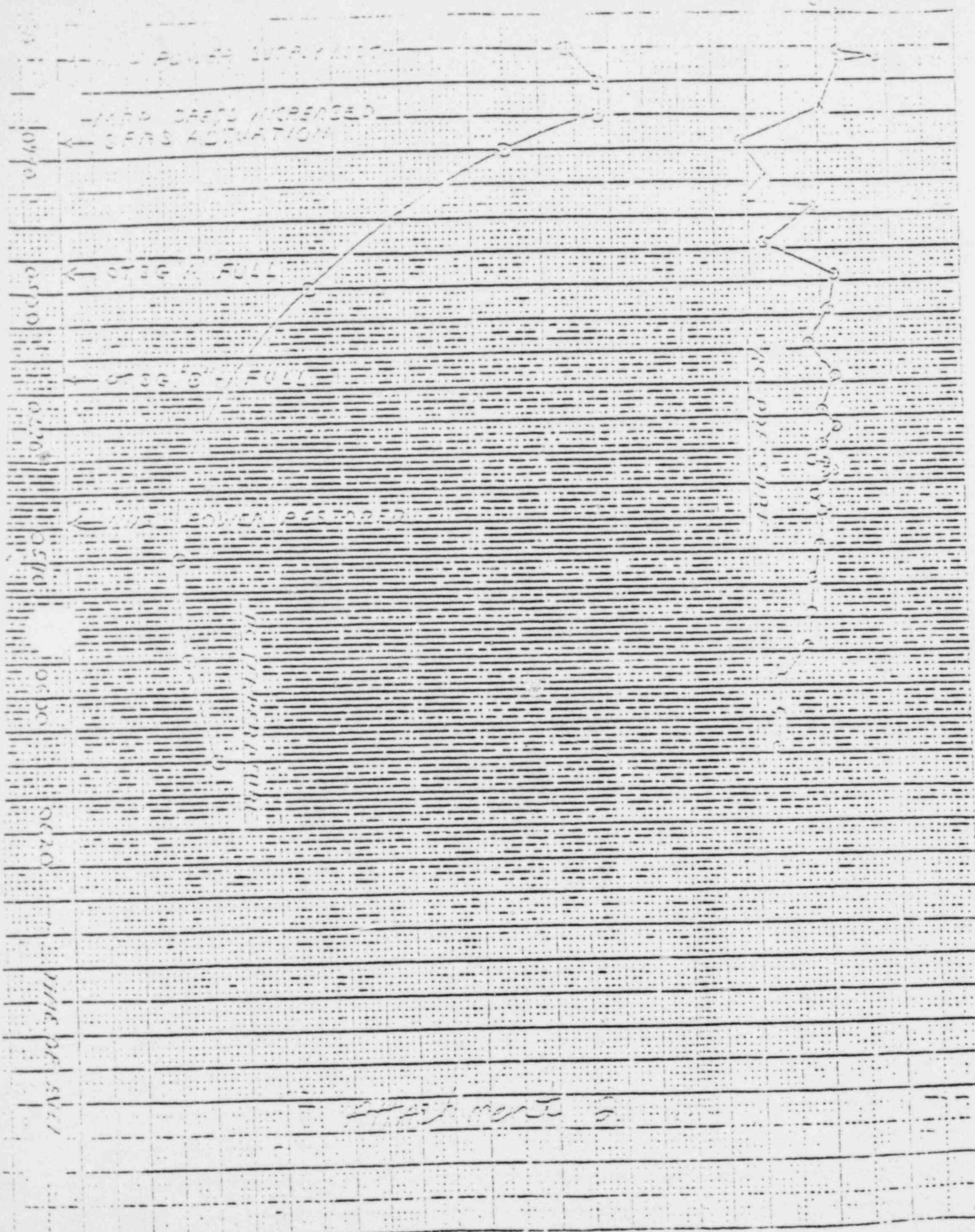
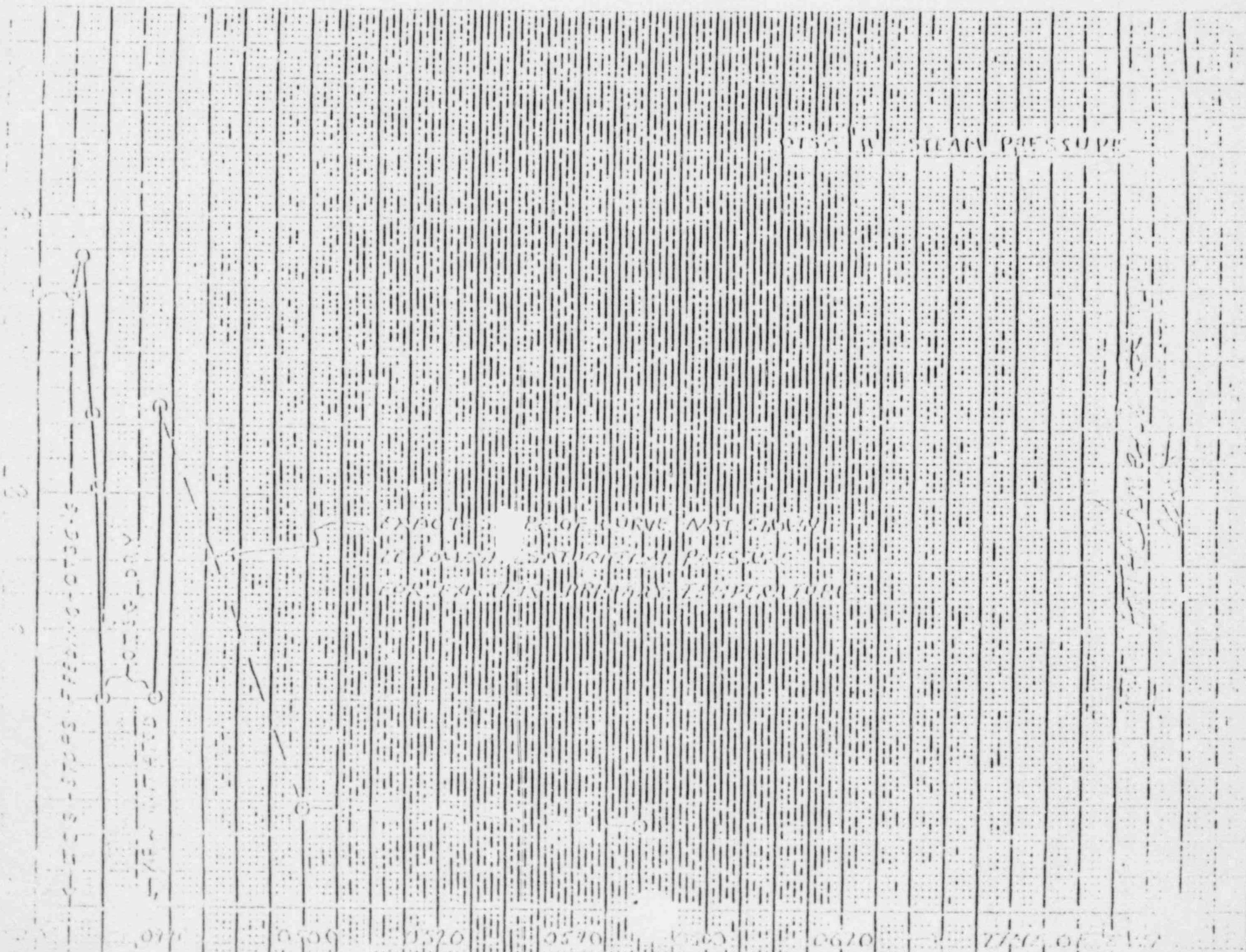


POOR ORIGINAL

46 1470


ICS STOPS FEEDING OTSG'S
OTSG DRY
AFW INITIATED
STEAM PRESSURE
TIME OF DAY

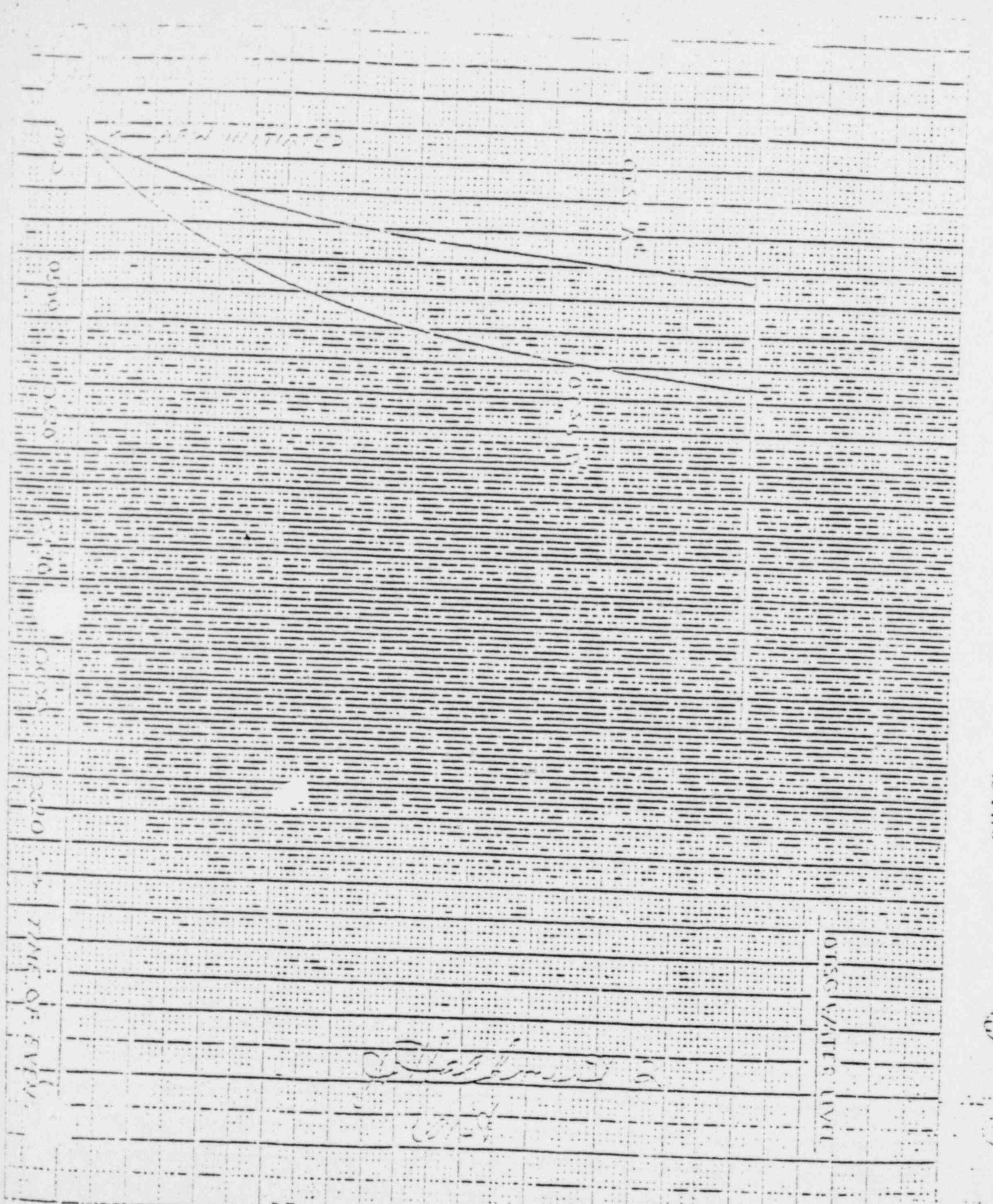
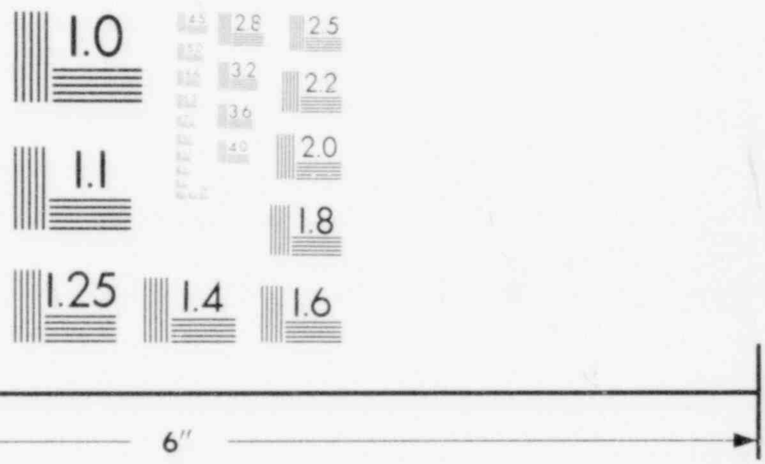


IMAGE EVALUATION
TEST TARGET (MT-3)



MICROCOPY RESOLUTION TEST CHART

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAR 29 1979

MEMORANDUM FOR: Domenic B. Vassallo, Assisant Director for Light Water Reactors, NRR

FROM: Dudley Thompson, XOOS

SUBJECT: INFORMATION FOR BOARD NOTIFICATION - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2
REFERENCES: 1. Memo: Thompson to Vassallo dtd 3/1/79
2. Memo: Thompson to Vassallo dtd 3/12/79

As noted in the above referenced submittals additional information in the form of staff discussion and evaluation would be forthcoming on the captioned board notification. Enclosed is the additional information for submittal to the appropriate Boards.

Dudley Thompson, Executive Officer
for Operations Support
Office of Inspection and Enforcement

Enclosures:
1. Memo: Moseley to Thompson dtd 3/28/79 w/encls
2. Memo: Moseley to Thompson dtd 3/29/79

cc: N. C. Moseley, IE, w/o encl
S. E. Bryan, IE, w/o encl
J. F. Streeter, RIII, w/encl
J. S. Creswell, RIII, w/encl
G. C. Gower, IE, w/encl
IE Files w/encl

CONTACT: G. C. Gower, IE
49-27246

POOR ORIGINAL

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

March 29, 1979

MEMORANDUM FOR: Dudley Thompson, Executive Officer for Operations Support, IE

FROM: Norman C. Moseley, Director, Division of Reactor Operations Inspection, IE

SUBJECT: NOTIFICATION OF LICENSING BOARDS

In light of the transient experienced at Three Mile Island on March 28, 1979, we will review our preliminary evaluation of Item 3 contained in my March 28, 1979 memorandum to you. It is possible that the additional information will cause our assessment to change.

Norman C. Moseley

Norman C. Moseley
Director
Division of Reactor
Operations Inspection, IE

cc: S. E. Bryan
E. L. Jordan
R. F. Heishman, RIII
J. C. Stone
D. C. Kirkpatrick
G. C. Gower
V. D. Thomas

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAR 28 1979

MEMORANDUM FOR: Dudley Thompson, Executive Officer for Operations Support, IE

FROM: Norman C. Moseley, Director, Division of Reactor Operations Inspection, IE

SUBJECT: NOTIFICATION OF LICENSING BOARDS

On February 23, 1979, six items concerning Babcock and Wilcox designed nuclear plants were sent to you for forwarding to the appropriate licensing boards. At that time only a preliminary evaluation had been done. We have completed our evaluation of each of the items and that information is enclosed. This additional information should be forwarded to the licensing boards.

Norman C. Moseley

Norman C. Moseley
Director
Division of Reactor
Operations Inspection, IE

Enclosure:
Evaluations of Concerns

cc: S. E. Bryan
E. L. Jordan
R. F. Heishman, RIII
J. C. Stone
D. Kirkpatrick
~~G. C. Gower~~
V. D. Thomas

CONTACT: J. C. Stone
(x28019)

EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

I. During a recent inspection at Davis-Besse Unit 1 information has been attained which indicates that at certain conditions of reactor coolant viscosity (as a function of temperature) core lifting may occur. The licensee informed the inspector that this issue involves other B&W facilities. The Davis-Besse FSAR states in Section 4.4.2.7:

> The hydraulic force on the fuel assembly receiving the most flow is shown as a function of system flow in Figure 4-39. Additional forces acting on the fuel assembly are the assembly weight and a hold down spring force, which resulted in a net downward force at all times during normal station operation.

The licensee states that there is a 500°F interlock for the starting of the fourth reactor coolant pump. However, no Technical Specification requires that the pump be started at or above this temperature. A concern regarding this matter would be if assemblies moved upward into a position such that control rod movement would be hindered.

DISCUSSION AND EVALUATION

The potential for core lifting in B&W plants is a concern which has been previously reviewed by NRR. The concern was first raised in connection with the Oconee 2 and 3 reactors, where the primary coolant flow rates were found to be in excess of the design flow rates. For example, the Unit 2 flow rate was found to be 111.5% of the design flow rate. Since this was very near the predicted core lift flow rate of 111.9%, an analysis was done by B&W to determine what effect core lifting would have on the previous safety analysis for these plants. This analysis (dated May 2, 1975) indicated that the potential for core lifting did not result in an unreviewed safety question. A subsequent review of this B&W analysis by NRR also concluded that an unsafe condition did not exist (letter from R. A. Purple to Duke Power, dated 9/24/75). It should be noted that the potential vertical displacement of the core is limited to a very small distance by the upper core support structure. Core lifting at power would result in a slight reduction in reactivity since the rising fuel would tend to engage the withdrawn control rods to a slightly greater extent than it would in the bottomed condition. The amount of this change in reactivity is, of course, available for reinsertion should the fuel settle back to its original position. The potential reactivity increase caused by the settling of the 16 centrally located control rod assembly elements (assumed to have been subject to lifting in the Oconee 2 reactor) was calculated to be 0.1% $\Delta K/K$. This value is insufficient to have much effect on the accident and transient safety analyses.

POOR ORIGINAL

An additional concern was the potential for damage to the fuel assembly end fittings which might be caused by fretting due to repetitive fuel movement. Consequently, Duke Power was requested by NRR to make certain examinations of the Oconee 2 fuel during the first refueling to confirm that fuel element motion was not occurring. The results of this examination (letter from W. O. Parker to R. C. Rusche dated 7/21/76) showed that no fuel lifting or other type of motion had occurred during the first cycle of operation.

After the core lift concern was identified, B&W developed newer types of fuel holddown springs which provide more margin against core lifting than the previous springs did. It is our understanding that the newer types of springs have been installed in all B&W reactors.

For these reasons, we believe that there is presently little likelihood that core lifting will occur during normal power operation. At lower temperatures, there is an increased flow induced lifting force on the fuel due to the higher viscosity of the reactor coolant. Consequently, we view the restriction against 4 pump operation below 500°F as a prudent precaution against fuel fretting. However, since the potential for core lifting has little safety significance and because critical operation below 500°F is not permitted, we have no basis to recommend including this restriction in the Technical Specifications.

POOR ORIGINAL

EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

2. Inspection Report 50-346/78-06, paragraph 4, reported reactivity - power oscillations in the Davis-Besse core. These oscillations have also occurred at Oconee and are attributed to steam generator level oscillations. B&W report BAW-10027 states in A9.2:

> The OTSG laboratory model test results indicated that periodic oscillations in steam pressure, steam flow, and steam generator primary outlet temperatures could occur under certain conditions.
>
> It was shown that the oscillations were of the type associated with the relationships between feedwater heating chamber pressure drop and tube nest pressure drop, which are eliminated or reduced to levels of no consequence (no feedback to reactor system) by adjustment of the tube nest inlet resistance. As a result of the tests, an adjustable orifice has been installed in the downcomer section of the steam generators to provide for adjustment of the tube nest inlet resistance and to provide the means for elimination of oscillations if they should develop during the operating lifetime of the generators. The initial orifice setting is chosen conservatively to minimize the need for further adjustment during the startup test program.

We also note that the effect on the incore detector system for monitoring core parameters during the oscillations is not clear.

DISCUSSION AND EVALUATION

Power Oscillations of the order of 1.5% of full power have been observed at all of the Oconee plants and are considered normal. In 1977 the power oscillations experienced by the Oconee 3 reactor increased to a maximum of 7.5% of full power. At that time the problem was reviewed by NRR with the conclusion that there was no significant safety consideration at that value (Note to B. C. Buckley from S. D. MacKay, dated January 27, 1978). It should be noted that the 7.5% power oscillations cause about a 1°F oscillation in core average temperature due to the short period of the oscillations. The important core safety parameters, which are, the departure from nucleate boiling ratio and the average maximum linear heat generation rate are affected very little by oscillations of this amplitude. The primary cause of the power oscillations is believed to be a fluctuation of the secondary water level in the steam generators. This can be minimized by increasing the flow resistance in the downcomer region of the steam generators. The corrective effort at Oconee 3 was complicated by the fact that the orifice plate provided for this purpose could not be fully closed.

However, the oscillations at other B&W plants have been kept to about 1.5% of full power by appropriate adjustment of the downcomer flow resistance. For these reasons, the power oscillations at B&W plants are not considered to be a significant safety concern.

[illegible] EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

3. Inspection and Enforcement Report [illegible] documented that pressurizer level had gone offscale for approximately five minutes during the November 29, 1977 loss of offsite power event. There are some indications that other B&W plants may have problems maintaining pressurizer level indications during transients. In addition, under certain conditions such as loss of feedwater at 100% power with the reactor coolant pumps running the pressurizer may void completely. A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1. Because of pressurizer level maintenance problems the sizing of the pressurizer may require further review.

Also noted during the event was the fact that Tcold went offscale (less than 520°F). In addition, it was noted that the makeup flow monitoring is limited to less than 160 gpm and that makeup flow may be substantially greater than this value. This information should be examined in light of the requirements of GDC 13.

DISCUSSION AND EVALUATION

The event at Davis Besse which resulted in loss of pressurizer level indication has been reviewed by NRR and the conclusion was reached that no unreviewed safety question existed.

The pressurizer, together with the reactor coolant makeup system, is designed to maintain the primary system pressure and water level within their operational limits only during normal operating conditions. Cooldown transients, such as loss of offsite power and loss of feedwater, sometimes result in primary pressure and volume changes that are beyond the a ility of this system to control. The analyses of and experience w th such transients show, however, that they can be sustained witho. compromising the safety of the reactor. The principal concern caused b such transients is that they might cause voiding in the primary coolant system that would lead to loss of ability to adequately cool the reactor core. The safety evaluation of the loss of offsite power transient shows that, though level indication is lost, some water remains in the pressurizer and the pressure does not decrease below about 1600 psi. In order for voiding to occur, the pressure must decrease below the saturation pressure corresponding to the system temperature. 1600 psi is the saturation pressure corresponding to 605°F, which is also the maximum allowable core outlet temperature. Voiding in the primary system (excepting the pressurizer) is precluded in this case, since pressure does not decrease to saturation.

The safety analysis for more severe cooldown transients, such as the loss of feedwater event, indicates that the water volume could decrease to less than the system volume exclusive of the pressurizer. During such an event, the emptying of the pressurizer would be followed by a pressure reduction below the saturation point and the formation of small voids throughout much of the primary system. This would not result in the loss of core cooling because the voids would be dispersed over a large volume and forced flow would prevent them from coalescing sufficiently to prevent core cooling. The high pressure coolant injection pumps are started automatically when the primary pressure decreases below 1600 psi. Therefore, any pressure reduction which is sufficient to allow voiding will also result in water injection which will rapidly restore the primary water to normal levels.

For these reasons, we believe that the inability of the pressurizer and normal coolant makeup system to control some transients does not provide a basis for requiring more capacity in these systems.

General Design Criterion 13 of Appendix A to 10 CFR 50 requires instrumentation to monitor variables over their anticipated ranges for "anticipated operational occurrences". Such occurrences are specifically defined to include loss of all offsite power. The fact that T cold goes off scale at 520°F is not considered to be a deviation from this requirement because this indicator is backed up by wide range temperature indication that extends to a low limit of 50°F. Neither do we consider the makeup flow monitoring to deviate since the amount of makeup flow in excess of 160 gpm does not appear to be a significant factor in the course of these occurrences.

The loss of pressurizer water level indication could be considered to deviate from GDC 13, because this level indication provides the principal means of determining the primary coolant inventory. However, provision of a level indication that would cover all anticipated occurrences may not be practical. As discussed above, the loss of feedwater event can lead to a momentary condition wherein no meaningful level exists, because the entire primary system contains a steam water mixture.

It should be noted that the introduction to Appendix A (last paragraph) recognizes that fulfillment of some of the criteria may not always be appropriate. This introduction also states that departures from the Criteria must be identified and justified. The discussion of GDC 13 in the Davis Besse FSAR lists the water level instrumentation, but does not mention the possibility of loss of water level indication during transients. This apparent omission in the safety analysis will be subjected to further review.

ENCL. 2 FROM MEMORANDUM ENTITLED "REPORTING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

4. A memo from B&W regarding control rod drive system trip breaker maintenance is attached to Enclosure 2. This memo should be evaluated in terms of shutdown margin maintenance and ATWS considerations particularly in light of large positive moderator coefficients allowable with B&W facilities.

DISCUSSION AND EVALUATION

Our investigation of the above circuit breaker problems has revealed that eight failures of reactor scram circuit breakers to trip during test have been reported from Babcock & Wilcox (B&W) type operating facilities since 1975. In each case, the faulty circuit breaker was identified as a GE type AK-2 series (i.e., AK-2A-15, 24, or 50). The causes for failure were attributed to either binding within the linkage mechanism of the undervoltage trip device (UV) and trip shaft assembly or an out-of-adjustment condition in the same linkage mechanism. B&W and GE determined that the binding and the out-of-adjustment conditions resulted from inadequate preventive maintenance programs at the affected operating facilities.

In addition to the breaker problems experienced at the B&W facilities, three circuit breakers of the aforementioned GE type failed in similar fashion at the Oyster Creek operating facility on November 26, 30, and December 2, 1978. As in each case above, cleaning and relubricating of the UV/trip shaft assembly within the circuit breaker was required to correct the problem. It is significant to note that during the November 30, 1978 event, both redundant service water pump circuit breakers failed to trip as required during the loss of off-site power test. These failures in turn created a potential overload condition on the emergency busses during the sequential bus loading by each diesel generator.

However, both diesel generators successfully picked up their required bus loads without experiencing a unit shutdown from an overload condition. With respect to the generic implications and safety significance of this issue, both B&W and GE are in the process of issuing alert letters to their customers. These letters are scheduled for issuance by late March and will describe the causes for failure and provide recommendations to resolve the problem.

Based on our study findings and on information obtained in discussions about the breaker problem with the knowledgeable people from B&W, GE and Region II, we plan to issue an IE Circular covering the matter. The thrust of the Circular will be directed toward the need for adequate preventive maintenance programs at all operating facilities. Specific recommendations from GE to resolve the above breaker problem will also be mentioned in the Circular.

EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

5. Inspection and Enforcement Report 50-346/78-17, paragraph 6 refers to inspection findings regarding the capability of the incore detector system to determine worst case thermal conditions. The reactor can be operated per the Technical Specifications with the center incore string out of service. If the peak power locations is in the center of the core (this has been the case at Davis-Besse) factor are not applied to conservatively monitor values such as F_Q and . delta H.

DISCUSSION AND EVALUATION

We do not believe that there is a valid basis for requiring the center string of incore detectors to be always operable in B&W reactors.

The power distributions for various plant conditions, throughout the fuel cycle, are calculated prior to the operation of the reactor. The power distribution is verified at the beginning of operation, and periodically thereafter, by comparison with the available incore detectors. The power in fuel assemblies that lack detectors (including those with failed detectors) is derived by using the known power distribution to determine the power ratios between such an assembly and nearby assemblies that have detectors. These ratios can then be multiplied by the power in the measured assemblies to derive the power level in any specific unmeasured assembly. The central assembly is not fundamentally different than any other assembly in this respect. Although this assembly is the highest powered assembly in the Davis Besse reactor at the beginning of the fuel cycle, this is not the case at all reactors. Nor does the central assembly have the highest power, in the Davis Besse reactor, at the end of the first fuel cycle. Since there is some variation between the calculated power distributions and the actual ones, an appropriate margin is assumed for this variation in establishing the allowable power peaking factors.

Fixed incore detectors must function in an extremely harsh environment and are subject to high failure rates. In order to ensure that an adequate number will survive the fuel cycle, many more detectors are installed than are necessary for the power distributions determinations. To require the central string to be always operable would likely result in unnecessary power restrictions. Neither the standard Technical Specifications (STS) for B&W plants nor the STS for CE plants (which also have fixed incore detectors) require the central detectors to be operable.

POOR ORIGINAL

EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER

6. Enclosure 3 describes an event that occurred at a B&W facility which resulted in a severe thermal transient and extreme difficulty in controlling the plant. The aforementioned facilities should be reviewed in light of this information for possible safety implications.

DISCUSSIO[illegible] EVALUATION

Following the cooldown transient at Rancho Seco, NRR evaluated the event and concluded that no structural damage had occurred to the primary coolant system which would preclude future operation of Rancho Seco. However, in their safety evaluations they concluded that positive steps should be taken to preclude similar transients and that the generic implications of this event should be reviewed. In addition, IE initiated a Transfer of Lead Responsibility, Serial No. IE-ROI 78-04, dated April 25, 1978, recommending that:

1. NRR perform a generic review of the non-nuclear instrumentation power supplies for other B&W units, if design changes to the non-nuclear instrumentation (NNI) power supplies are required at Rancho Seco.

2. NRR evaluate the susceptibility of B&W plants to other initiating events or failures which could cause similar significant cooldown transients.

This event is currently being evaluated by NRR.

ENCLOSURE 7

TOLEDO EDISON

October 7, 1977

L77-312

FILE: RR.2 (NP-32-77-16)

Docket No. 50-346
License No. NPF-3

Mr. James G. Keppler
Regional Director, Region III
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Dear Mr. Keppler:

Reportable Occurrence NP-32-77-16
Davis-Besse Nuclear Power Station Unit 1
Date of Occurrence: September 24, 1977

Enclosed find three copies of Licensee Event Report NP-32-77-16 with a supplemental information sheet, which is being submitted in accordance with Technical Specification 6.9 to provide 14 day written notification of the subject occurrence.

Yours truly,

J Evans/[illegible]

Jack Evans
Station Superintendent
Davis-Besse Nuclear Power Station

JGE/JRL/ljk

Enclosures

cc: Dr. Ernst Volgenau, Director
Office of Inspection and Enforcement
Encl: 40 copies Licensee Event Report
40 copies Supplemental Information Sheet

Mr. William G. McDonald, Director
Office of Management
Information and Program Control
Encl: 3 copies Licensee Event Report
3 copies Supplemental Information Sheet
2 copies Telecopied Report

bcc: L. E. Roe
J. S. Grant
E. C. Novak
J. H. Barker
J. D. Lenardson
P. P. Anas
Dr. Ralph E. Lapp
Mr. Charles M. Rice
Edison Electric Institute
Company Nuclear Review Board Members

NRC FORM 366

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT

EXHIBIT A

CONTROL BLOCK: (PLEASE PRINT OR TYPE ALL REQUIRED INFORMATION)

LICENSEE CODE: O H D B S 1 — LICENSE NUMBER: 0 0 - 0 0 0 N P F - 0 3 — LICENSE TYPE: 4 1 1 1 1

CON'T REPORT SOURCE: L — DOCKET NUMBER: 0 5 0 - 0 3 4 6 — EVENT DATE: 0 9 2 4 7 7 — REPORT DATE: 1 0 0 7 7 7

EVENT DESCRIPTION AND PROBABLE CONSEQUENCES

Half trip of the Steam and Feedwater Rupture Control System (SFRCS) causing a rise in Reactor Coolant System (RCS) temperature and pressure. This resulted in the pressurizer power relief valve to open and this valve failed to close, causing a reduction in RCS pressure. Limiting Conditions For Operation were exceeded for five Technical Specifications, 3.4.1, 3.4.5, 3.4.6.2, 3.6.1.4 and 3.7.1.2. (NP-32-77-16)

SYSTEM CODE: I E — CAUSE CODE: X — CAUSE SUBCODE: Z — COMPONENT CODE: I N S T R U — COMP. SUBCODE: X — VALVE SUBCODE: Z

LER/RO REPORT NUMBER: EVENT YEAR 7 7 — SEQUENTIAL REPORT NO. 0 1 6 / OCCURRENCE CODE 0 1 — REPORT TYPE T — REVISION NO. 0

ACTION TAKEN: X — FUTURE ACTION: X — EFFECT ON PLANT: A — SHUTDOWN METHOD: B — 0 0 6 0 — ATTACHMENT SUBMITTED: Y — NPRD-4 FORM SUB.: N — PRIME COMP. SUPPLIER: N — COMPONENT MANUFACTURER: C 5 6 0

CAUSE DESCRIPTION AND CORRECTIVE ACTIONS

The cause of the occurrence was a half trip condition from SFRCS Channel 2, which caused valve FWSP7A to close. The cause of this half trip has not been positively determined although extensive investigation has revealed loose connections at terminal boards (possible cause).

FACILITY STATUS: D — % POWER: 0 0 9 — OTHER STATUS: NA — METHOD OF DISCOVERY: A — DISCOVERY DESCRIPTION: Operator Observation

ACTIVITY CONTENT — RELEASED OF RELEASE: Z — Z — AMOUNT OF ACTIVITY: NA — LOCATION OF RELEASE: NA

PERSONNEL EXPOSURES — NUMBER: 0 0 0 — TYPE: Z — DESCRIPTION: NA

PERSONNEL INJURIES — NUMBER: 0 0 0 — DESCRIPTION: NA

LOSS OF OR DAMAGE TO FACILITY — TYPE: D — DESCRIPTION: Duct work bent, metal reflective insulation damaged

PUBLICITY — ISSUED: Y — DESCRIPTION: 09/25/77 - Press Release

NAME OF PREPARER: Larry C. Stalter — PHONE: 419-259-5661

DVR #137-1

TOLEDO EDISON COMPANY
DAVIS-BESSE UNIT ONE NUCLEAR POWER STATION
SUPPLEMENTAL INFORMATION FOR LER NP-32-77-16

DATE OF EVENT: September 24, 1977

FACILITY: Davis-Besse Unit 1

IDENTIFICATION OF OCCURRENCE: Half trip of the Steam and Feedwater Rupture Control System (SFRCS) causing a rise in Reactor Coolant System (RCS) temperature and pressure resulting in the pressurizer power relief valve to open, and this valve failed to close.

Conditions Prior to Occurrence: The plant was in Mode 1, with Power (MWT) = 263, and Load (MWE) = 0.

Description of Occurrence: At 2134 hours on Saturday, September 24, 1977, a "half trip" of the SFRCS was initiated by an as yet unknown cause. This initiated the closure of the Startup Feedwater Valve FWSP7A, which supplies water to the No. 2 Steam Generator (SG-2).

The reduction of water level in SG-2 resulted in a corresponding rise in RCS temperature and pressure. When the RCS pressure reached 2255 psig, the Pressurizer Power Relief Valve lifted nine times, then stuck open. The discharge from the Power Relief Valve goes to the Pressurizer Quench Tank and with the Power Relief Valve in the stuck open position, the Pressurizer Quench Tank Rupture Disc ruptured, and the escaping steam caused increase in Containment pressure.

The Reactor Operator observed the pressurizer level rising to above 290 inches, and he manually tripped the reactor. The system was now in a cooldown and depressurization cycle. Within six minutes, the pressure had reached the saturation pressure for the corresponding temperature and steam began to form within the RCS causing an insurge of water into the pressurizer. Pressurizer level went to its maximum (320 inches).

At approximately 2155 hours, the operators determined that the Power Relief Valve had stuck open, and they isolated it by closing the block valve. This action terminated the RCS depressurization, and recovery of RCS pressure and subsequent cooldown to Mode 5, Cold Shutdown followed.

The LIMITING CONDITIONS FOR OPERATION were exceeded for five Technical Specifications:

1. 3.4.1 Reactor Coolant Loops - Two Reactor Coolant Pumps were tripped during the incident to limit further heatup. The required action for Modes 3, 4 and 5 was met in that either a Reactor Coolant Pump (RCP) was in operation, or one Decay Heat Removal Pump was in operation at all times.

2. 3.4.5 Steam Generators - The level in both steam generators went below 18 inches.

3. 3.4.6.2 Operational Leakage - During the incident, there was a pressure boundary leakage and greater than 1 GPM unidentified leakage.

4. 3.6.1.4 Containment Systems Internal Pressure - The containment pressure exceeded the 25 inches W.G. allowable.

5. 3.7.1.2 Auxiliary Feedwater System - Auxiliary Feedwater Pump 1-2 failed to attain full speed upon receiving initial start signal.

NOTE: The ACTION items for the above specifications were met in that the unit was in Hot Standby within 6 hours and Cold Shutdown within the next 30 hours.

Designation of Apparent Cause of Occurrence: The apparent cause of this occurrence was determined to be a half trip condition from SFRCS Channel 2 causing valve FWSP7A to close. The cause of the half trip was not positively determined although extensive investigation has revealed several loose connections at terminal boards which could have been the cause.

Analysis of Occurrence: There was no danger to the health and safety of the public or to station personnel. It was determined that the Steam Generator No. 2 was boiled dry during this incident. Babcock and Wilcox has reviewed the transients on the primary system and has determined that these transients are within the design transients allowance for the primary system.

Investigation into the failure of the power relief valve revealed that the close relay was missing from its control circuit. This relay provides a seal in circuit which holds the Power Relief Valve open until the RCS pressure drops to 2205 psig. With the relay missing the Power Relief Valve closed when the RCS pressure dropped below 2255 psig and re-opened when pressure rose above 2255 psig. Thus, the valve cycled nine times in rapid succession causing failure of the pilot valve stem, resulting in the Power Relief Valve to remain open.

The No. 2 Auxiliary Feedwater Pump did not go to full speed due to binding in the turbine governor.

All other systems functioned as designed.

Corrective Action: Since there was no positive determination of the cause of the half trip in the SFRCS, this system will be monitored during the next power escalation to detect any spurious signals. Plans are also being developed to add additional annunciator alarm windows from the SFRCS and to seal in any alarm condition.

The Power Relief Valve was repaired and returned to service. The missing relay was replaced. Testing of the Power Relief Valve will be completed prior to Mode 2.

The binding in the Auxiliary Feed Pump Governor was identified and the governors were returned to the factory for modifications to prevent binding. Post modification testing will be completed on the Auxiliary Feed Pumps prior to Mode 2.

Failure Data: One previous occurrence of a half trip initiation of the SFRCS occurred.

ENCLOSURE 8

TOLEDO EDISON

L77-380

FILE: RR.2 (NP-32-77-16)

November 14, 1977

Docket No. 50-346
License No. NPF-3

Mr. James G. Keppler
Regional Director, Region III
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Dear Mr. Keppler:

Supplement to Reportable Occurrence NP-32-77-16
Davis-Besse Nuclear Power Station Unit 1
Date of Occurrence: September 24, 1977

Enclosed find three copies of Licensee Event Report NP-32-77-16 Supplement, which is being submitted in accordance with Technical Specification 6.9 to provide additional information of the subject occurrence.

Please note this report also satisfies the special 90 day report requirement of Technical Specification 6.9.2 for the Emergency Core Cooling Actuation on September 24, 1977.

Yours truly,

Terry D Murray

Terry D. Murray
Station Superintendent
Davis-Besse Nuclear Power Station

TDM/JRL/ljk

Enclosures

cc: Dr. Ernst Volgenau, Director
Office of Inspection and Enforcement
Encl: 40 copies Supplement

Mr. William G. McDonald, Director
Office of Management
Information and Program Control
Encl: 3 copies Supplement

bcc: L. E. Roe
J. S. Grant
E. C. Novak
J. E. Barker
J. D. Lenardson
P. P. Anas
Dr. Ralph E. Lapp
Mr. Charles M. Rice
Mr. Warren E. Nyer
Edison Electric Institute
Company Nuclear Review Board Memb-

1. SUMMARY

On September 24, 1977, a series of events occurred at the Davis-Besse Unit 1 which resulted in depressurization of the primary system from a normal operating pressure of 2150 psi to 900 psi in approximately 8 minutes, and the release of approximately 11,000 gallons of water in the form of steam within the containment through the pressurizer quench tank rupture disc.

On the afternoon of Saturday, September 24, 1977, the main turbine was shut down to repair a leak in a pressure sensing connection on a steam line from the turbine governing valves to the turbine inlet. The reactor was being held critical at approximately 9% thermal power.

At 2134 hours, a spurious half trip occurred in the Steam Feedwater Rupture Control System (SFRCS). This caused the startup feedwater valve on the No. 2 steam generator (which is the normal feed path at this power level) to close. Closure of this valve resulted in a low No. 2 steam generator level, which then resulted in a normal full trip of the SFRCS for this condition and initiation of the SFRCS. SFRCS initiation closes both main steam isolation valves and initiates feedwater flow to both steam generators from their individual steam-driven auxiliary feedpumps.

The half trip and resulting full trip of the SFRCS caused a reduction in heat removal from the primary system and a corresponding temperature/pressure rise in the primary system. The pressure rise in the primary system caused the pressurizer power relief valve to lift. This valve then rapidly oscillated closed-to-open approximately nine times and remained in the full open position.

The temperature rise in the primary system caused an increase in the pressurizer level, and the operator manually tripped the reactor on high pressurizer level approximately two minutes after the half trip on the SFRCS occurred.

The pressurizer power relief valve, in the full open position, rapidly reduced the primary system pressure, and a Safety Features Actuation System (SFAS) trip occurred at the 1600 psi setpoint of the primary system. The power relief valve discharge goes to the pressurizer quench tank, which became overloaded and overpressurized, and approximately 4½ minutes after reactor trip the rupture disc in this tank relieved due to overpressure, venting the steam into the containment. Approximately 20 minutes after reactor trip, the operators diagnosed the reason for the primary system depressurization as being the power relief valve, and from the control room closed the motorized block valve ahead of the power relief valve, terminating the loss of primary coolant into the containment.

Subsequent operator action using makeup pumps and high pressure injection pumps stabilized the primary system pressure and pressurizer level and a controlled shutdown to cold shutdown conditions followed.

The major physical damage from the incident was to the reflective metal insulation on the lower part of the No. 2 steam generator, which received the jet of steam coming from the pressurizer quench tank. A ventilating duct in the area of the quench tank was dimpled and required straightening. Twenty-three panels of reflective metal insulation required replacement. Entry into the containment was made at 0550 Sunday, September 25, 1977, for cleanup operations.

Another event occurred in the course of this incident that did not contribute materially to the above events, but did result in the No. 2 steam generator going dry. This was the failure of the No. 2 auxiliary feedpump to come up to full speed following the SFRCS trip. This feedpump came up to approximately 2600 rpm and stayed at this level with no flow to the steam generator until approximately 12 minutes after reactor trip, when the operators placed its control in manual and brought it up to full speed (commencing feedwater flow to the steam generator).

The depressurization of the primary system resulted in steam formation in the primary system, but evaluation has shown there was no appreciable boiling in the core. The pressure/temperature transients in the primary system components including the steam generator, reactor coolant pumps and fuel were severe, but analysis and subsequent pump testing has shown that these transients are within the design allowables and that no detrimental effects are to be expected on the primary system, pumps or fuel.

System/component maloperation or failure occurred in three areas: SFRCS (half-trip initiation), pressurizer power relief valve (oscillation and failing in the open position) and auxiliary feedpump (failure to come up to full speed). The causes of these maloperation/failures have been investigated and corrective action taken to prevent recurrence. Additional system/equipment modifications have been completed or initiated, and additional training has been initiated to strengthen the systems intelligence available to the operators and facilitate operator action.

At no time during the sequence of events was there any jeopardy to the health and safety of the public or plant operators, and there was no release of radioactivity to the environment. Activity levels within the containment at no time impeded containment access.

All safety systems performed their design functions in the proper manner. Operator action was timely and proper throughout the sequence of events.

2. EVENT DESCRIPTION

At the time this incident occurred, the reactimeter data logging system was in service which recorded at high speed a number of system parameters that would not have been available on such a time base through normal station instrumentation and records. This information, together with the computer alarm logging, has permitted a very detailed plotting of the transient conditions in the primary and secondary systems keyed to the system, component and operator actions. This data is plotted on four Figures in Exhibit B. Figure 1 is an 11-minute plot of primary system parameters from one (1) minute prior to event initiation (SFRCS half trip). Figure 2 is a 130-minute plot of three primary system parameters. Figures 3 and 4 are 95-minute plots of pressure and temperature for steam generators No. 1 and No. 2 respectively.

The event started at time 21:34:20 (T = 0) on September 24, 1977. The plant was in Mode 1 with Power (MWT) = 263. The turbine had been shutdown earlier in the evening to repair a leak in the main steam line at an instrument connection between the turbine stop valves and the high pressure turbine. At this time a half trip of the Steam and Feedwater Rupture Control System (SFRCS) was initiated by an unknown cause. The trip closed the startup feedwater valve to No. 2 steam generator and stopped all feedwater to this generator (at this low power level the main feedwater block valve is closed, isolating the main feedwater control valve). The low level alarm was reached in No. 2 steam generator at T = 24 sec. Before the operator could identify and correct the problem, this low level in No. 2 steam generator correctly produced a full trip of the SFRCS. This trip closed the main steam isolation valves and feedwater isolation valves in both steam generators (T = 58 sec.). SFRCS initiation also started both auxiliary feedwater pumps. The number one pump performed as intended, however, number two auxiliary feedwater pump only came up to 2600 rpm, insufficient to feed its steam generator (No. 2).

The loss of feedwater, first to one and then both steam generators, caused an increase in reactor coolant temperature, which resulted in an increase in pressurizer level and reactor coolant system pressure. At 2255 PSIG the pressurizer electromatic relief valve received an open signal. During the next 40 seconds, it received open and close signals, cycled close-to-open nine times and then remained open. This provided a continuous vent path from the pressurizer to the quench tank. When pressurizer level rose to 290", the operator manually tripped the reactor (T = 1 min. 47 sec.). Energy escaping through the electromatic relief valve and main steam relief valves caused a rapid cooldown and depressurization of the reactor coolant system. Reactor coolant system pressure dropped to 1600 PSIG (T = 2 min. 51 sec.) initiating the Safety Features Actuation System (SFAS). This started the high pressure injection pumps and closed certain containment isolation valves.

With the electromatic relief valve still open, the quench tank rupture disc ruptured (T = 6 min.), relieving steam into the containment.

When the reactor coolant system pressure decayed to approximately 1500 psig full high pressure injection flow was established and started to raise pressurizer level. At T = 6 min. 14 sec. the operator stopped the high pressure injection pumps. (The operators had been heavily involved before this time in regaining seal injection flow to the reactor coolant pumps which had been stopped by the SFAS actuation. By T = 5 min. 20 sec. the appropriate SFAS signals had been overridden and normal flows restored to the seals of the pumps). Reactor coolant system pressure continued to decrease until saturation pressure was reached and steam began to form in the reactor coolant system (approximately T = 8 min). This caused an insurge of water into the pressurizer and the pressurizer level went off scale at 320 inches. During this level increase the operator, seeing average reactor coolant system temperature and pressurizer level increasing, stopped one reactor coolant pump in each loop (T = 9 min.) to reduce the heat input into the reactor coolant system.

Due to decreasing pressure in No. 2 steam generator, the SFRCS system gave a low pressure block permit signal at T = 14 min. 13 sec. This alerted the operator to the low level and feed condition of No. 2 steam generator. He blocked the low pressure trip (T = 15 min. 18 sec.), took manual control of the speed of No. 2 auxiliary feedwater pump, which commenced full feedwater flow to No. 2 steam generator (T = 16 min.). The operator saw the rapid addition of cold feedwater into No. 2 steam generator was dropping the reactor coolant system temperature and reduced the feedwater addition to this generator.

At approximately T = 21 min., it was determined that the power relief valve was remaining open and the block valve was closed, isolating the power relief valve on the pressurizer and stopping the venting of the reactor coolant system to the quench tank. At T = 31 min., pressurizer level came back on scale. At T = 41 min. the operator started a second makeup pump to try and stop the pressurizer level decrease. This additional cold water started the reactor coolant system on a slow decreasing temperature transient. At T = 43 min., pressurizer level reached the low level interlock and cut off the pressurizer heaters. At T = 49 min. the operator started a high pressure injection pump to try and stop the decreasing pressurizer level.

The level and pressure in No. 2 steam generator again decreased to the point where the SFRCS gave a low pressure block permit signal. The operator again blocked the trip and, through manual speed control of its auxiliary feedwater pump, restored level and pressure in No. 2 steam generator (T = 51 min.)

With pressurizer level well on its way to recovering, the operator stopped the high pressure injection pump (T = 53 min. 24 sec.). At T = 57 min. he restored reactor coolant makeup flow to normal. This stopped the slow decreasing reactor coolant temperature transient which started at T = 41 min. All plant parameters were now fully under control and the plant was brought to a steady state condition, and a normal plant cooldown started.

3. SYSTEM-EQUIPMENT MALFUNCTION

A. General

There were three systems/components where maloperation or failure occurred during the event. These are:

1. Steam Feedwater Rupture Control System - SFRCS (half-trip initiation)

2. Power Relief Valve (oscillation and failing in the open position)

3. Auxiliary Feedpump (failure to come up to full speed)

The SFRCS is a safety system designed to provide feedwater to the steam generator/s for removal of decay heat from the primary system under a variety of hypothesized plant operating conditions.

These hypothesized conditions include loss of normal feedwater flow, steam line breaks and feedwater line breaks. The components of this system include sensing systems, logic and initiation systems, main steam isolation valves, steam turbine-driven auxiliary feedwater pumps, feedwater isolation valves, auxiliary steam and feedwater supply valves and cross connect valves. A description of this system is contained in Exhibit C of this report.

A half trip of the SFRCS initiated this event by closing the startup feedwater valve to the No. 2 steam generator, which resulted in a full trip due to low steam generator level. This spurious or inadvertent half trip, and possible reasons for it occurring, are discussed in more detail below.

The pressurizer power relief valve is a 2½" pilot-actuated relief valve connected to the top of the pressurizer with a motor-operated isolation or block valve located in the line immediately ahead of the relief valve. The purpose of this power relief valve is to provide a means of relieving pressurizer pressure without requiring operation of the spring-loaded ASME Code relief valves.

During this event, the power-operated relief valve opened, oscillated closed-to-open and then failed to close and remained in the open position. Operator action from the control room closed the isolation valve ahead of the power relief valve about 20 minutes after reactor trip.

The reasons for the oscillations and the failure of the power relief valve to close are discussed in more detail below.

The steam turbine-driven auxiliary feedwater pumps are a part of the SFRCS. Upon initiation of the SFRCS, the auxiliary steam supply valve to the feedwater pump turbine opened as called for. The No. 2 auxiliary feedwater pump turbine came up to 2600 rpm and remained at this speed rather than continuing up to 3600 rpm, which is the design speed. Operator action at 14 minutes after reactor trip brought this pump up to design speed by placing the control (in the control room) in manual. Failure of this pump to come up to speed did not materially contribute to this event, but did result in the No. 2 steam generator boiling dry, which added to the transient condition in the primary system.

The reasons for this feedwater pump turbine to come up to speed are discussed in detail below.

B. SFRCS

The initiating event was a Steam and Feedwater Rupture Control System (SFRCS) Channel 2 momentary one-half trip from an unknown cause that went back to normal before the station computer could record the source. This one-half trip caused the following events:

1. The startup feedwater control valve (SP7A) on steam generator No. 2 closed. This caused a loss of feedwater incident on steam generator No. 2.

2. A one-half trip on Channel 2 sealed in on both main steam line isolation valves (MSIV). This one-half trip deenergized at least one solenoid valve on each MSIV, and resulted in a "Mn Stm Iso 1 (2) Trbl" alarm on the station computer for both MSIV's.

   This momentary one-half trip could have been caused by a spurious contact opening or a loose connection in a wire in a SFRCS input signal from a steam generator low pressure switch, a steam generator low level bistable or a main feedwater high pressure differential switch. The momentary one-half trip could also have been caused by trouble internal to the SFRCS cabinets. All possible causes were investigated. As a result of this investigation, it was determined that an input buffer card had failed.

C. Auxiliary Feedpump Turbine Governor

The auxiliary feedpump No. 2 failed to accelerate to the normal speed of 3600 rpm. The steam isolation valve opened properly and the pump came up to about 2600 rpm. The governor, a Woodward Type PG-PL with a speed changer motor driving the manual speed setting knob, was calling for a higher speed (the speed changer motor was turning in the "increase" direction). As required, the governor was left in accordance with procedures with the speed adjustment at the "full speed" position when the pump was shutdown. When the pump was called on to auto-start, with steam generator level below setpoint, the speed changer motor continued to drive, through a slip clutch, in the "increase" direction. However, the speed setting mechanism was already at its mechanical high speed stop applying a binding torque to the "T" bar, a portion of the "feed back" linkage, not allowing it to drop down and allow the piston rod to move down in the increase speed direction. The undesired binding in the feedback linkage gave the governor a false signal that the turbine was at the desired speed. Once the torque was removed, by operator remote manual action, from the "T" bar, the "T" bar dropped down and the auxiliary feed pump turbine proceeded to the high speed stop (3600 rpm).

D. Pressurizer Power Relief Valve

When the reactor coolant system pressure reached the setpoint for the power relief valve, 2255 psig, the valve opened properly. However, there is a seal-in relay which then keeps the valve open until pressure is reduced to a lower "reset" pressure (2205 psig). This seal-in relay that controls the closing of the valve was missing from the circuit. Without the relay, the valve reclosed as soon as pressure decreased below the "open" setpoint. The result was open-close cycles as pressure went above and below the "open" setpoint pressure instead of one or two longer blows to relieve the high pressure down to the "reset" pressure.

After approximately nine open-close cycles the power relief valve remained in the open position. When the valve was disassembled it was found that the pilot valve was stuck in the open position causing the main valve to stay open. The pilot valve was stuck in the open position due to unknown foreign material binding the stem in the guide area of the pilot valve nozzle.

4. SYSTEM TRANSIENTS AND ANALYSIS

A. Transients

During this rapid depressurization event (see section 2 above and Exhibit B, Figures 7-1 through 7-4), the reactor coolant system pressure dropped from about 2300 psig to about 930 psig in 7½ minutes and gradually recovered to 1800 psig in two hours (see Figure 4-1). During this 7½ minutes the reactor coolant outlet temperature dropped at varying rates from about 580 F to about 533 F. Approximately 30 minutes after this initial temperature change, a second slower and smaller temperature change from 540 F to 505 F occurred over a 21-minute period. Following this second temperature decrease, the temperature gradually increased over a 2-hour period to 528 F. The reactor coolant inlet temperature changes and durations were similar to those of the reactor coolant outlet temperature (see Figure 4-2).

The secondary side pressure in steam generator No. 1 reached a maximum of 1050 psig and decreased to about 860 psig within 15 minutes (see Figure 4-3). The secondary side pressure in steam generator No. 2 reached a maximum of [illegible]30 psig, decreased to 610 psig in 14 minutes, and returned to 860 psig in 2 minutes. Twenty minutes later the pressure in steam generator No. 2 again decreased to 610 psig and gradually recovered over a 2-hour period (see Figure 4-4).

B. Analysis of the Reactor Coolant System

B&W has completed its evaluation of the September 24 transients and has found no harmful short or long-term effects on the reactor coolant system components. For this evaluation it was conservatively assumed that the total temperature decrease occurred at the initial rate. This results in a 49° F decrease in the reactor coolant outlet temperature over a 6-minute period.

The design specification for Davis-Besse Unit 1 required the evaluation of 40 cycles of a rapid depressurization event, which included a decrease in the reactor coolant pressure from 2200 psig to 800 psig, a change in the reactor coolant system average temperature from 563 F to 500 F in 15. minutes, and a decrease in secondary system pressure from 1050 psig to 640 psig.

The major difference between the actual transient and the design transient is the rate of the temperature change in the reactor coolant system. The actual rate of temperature change was twice the rate of the design transient, but the total temperature change was only 78% of that of the design transient. The net result is that the fatigue usage of this one rapid depressurization is about the same as that predicted for one cycle of the design transient.

As a more direct comparison, the ansient event identified was analyzed for the reactor vessel shell and compared to the design transient. The results were that the range in thermal radial gradient stress for the actual transient was 5400 psi, and the range of thermal radial gradient stress for the design transient was 6600 psi. This comparison would be representative of other thicknesses throughout the reactor coolant system pressure boundary.

The conclusions of the analysis are:

(1) Stresses in the pressure boundary did not exceed those already calculated on a design basis. This is verified by the actual pressure not exceeding 2500 psig and the thermal transient being less severe than a combination of design transients for a rapid depressurization and a reactor trip.

(2) Fatigue life of the reactor coolant components is not affected if one cycle of the reactor trip design transient and two cycles of a rapid depressurization design transient are considered to be used for this transient. Two cycles of the rapid depressurization transient are necessary because the HPI system was actuated twice during the event and two cycles are necessary to reflect the thermal transient in the high pressure injection nozzle.

The effect of the entire event on the fatigue life of the steam generators can be accounted for by using one cycle of the design transient for rapid depressurization and one cycle of the design transient for loss of feedwater to one generator.

(3) The effect of the change in water level on the pressurizer has a very minor effect on the pressurizer shell stresses. The pressurizer has been previously analyzed for the thermal effect of water-steam interface, and the change of level does not affect that analysis.

(4) No significant thermal shock should occur to the heaters, because the heaters were deactivated due to a low water level sensor and not reactivated until the level recovered.

(5) No dynamic effects were caused by the rapid pressure decrease. No specific analysis was done, but a dynamic response of the shells would require a large pressure change in the order of milliseconds, and the actual change was on the scale of minutes.

The reduced feedwater flow to steam generator No. 2 was not sufficient to maintain a water level during the first five minutes of the event and this steam generator boiled dry. The primary concern with a dry generator is the tube to shell temperature difference. In this event a water level was established before the system cooldown was started, and acceptable tube to shell temperature differences were maintained. This condition is similar to the loss of feedwater design transient, followed by restart of a dry pressurized generator using the auxiliary feedwater system.

The burst rupture disc on the pressurizer quench tank resulted in a stream of steam and water impinging on steam generator No. 2. This stream removed a section of insulation 10' high and 20' wide from the lower shell of the generator and impinged directly on the generator shell. The temperature of the impinging water was assumed to be 212° F. A conservative evaluation of the rapid temperature change in this local region of the vessel shell was performed. The results of this evaluation indicate that this one event used less than 1% of the total fatigue life of the vessel. The predicted fatigue usage factor for the 40-year design life of the vessel in this area was less than 0.10. This jet impingement did not significantly reduce the fatigue life of the steam generator.

The reactor coolant pumps (RCP) experienced the following conditions during the September 24 transient.

All four RC pumps were subjected to the following:

0:00	Reactor trip
1:10	SFAS trip
1:12	Seal return valves shut for 1:16
1:13	Seal injection valves shut for 1:52 All four pumps operated for 1:15 with no seal injection and no seal return flow during the RCS de-pressurization
2:28	Seal return valves open
3:05	Seal injection valves open
6:00	Steam formation Pressure oscillating near P_{SAT} for 30 to 45 minutes
36:07	Total seal injection flow low alarm

Pump 1-1:

7:04	Pump tripped
7:43	Shaft stopped
36:07	About one minute of low seal injection flow (near 2 gpm) Flow imbalance starved seal injection
36:30	Seal return valve shut
1:12:55	Standpipe level high
1:17:07	Standpipe level normal

Pump 2-2:

4:20	High vibration
7:04	Pump tripped
36:07	Lost seal injection for about one minute
36:22	Seal return valve shut for about 40 seconds

Checkout of the reactor coolant pumps was initiated to assess whether maintenance and/or repair was required as a result of the transient.

Operational checks were required to demonstrate that no significant damage had occurred to the pump bearings, shaft and seals. The first series of tests were performed in Mode 5 due to operational restrictions. Later operational checks were performed in Mode 3. Each pump was to be operated individually for a duration not to exceed ten (10) minutes, providing all defined parameters remained within established limits.

The operational sequence was as follows:

1. Lift pumps were started and pump shafts rotated by hand. Torque values were not to exceed 200 ft-lbs. A stethoscope was provided to detect any unusual mechanical noises in seal housing area. (This was satisfactorily completed on 10/3/77).

2. Mode 5 testing at 225 psig.

   2.1 Instrumentation Required:

   a. Upper and lower cavity pressures - all four pumps.

   b. Both horizontal vibration probes - all four pumps.

   c. System pressure or suction pressure.

   d. Vertical probe on 2-2 pump.

   e. Standpipe leakage was collected and measured during the test.

   2.2 Computer Data -

   Printout NSS special summary trend for running RCP every 15 seconds.

   2.3 The following limits were not to be exceeded:

   a. Shaft vibration - 15 mils peak to peak.

b. Total standpipe leakage (upper seal leakage) plus seal return should not exceed 0.6 gpm. If, during the test this limit is exceeded, the possibility exists of an open seal. In no case will total seal leakage be allowed to exceed 1.5 gpm. If this limit is exceeded, maintenance will be required before further pump operation.

c. All other normal plant limits and precautions prevail.

2.4 Sequence of Operation:

a. Secure standpipe flush.

b. Establish seal injection in accordance with plant operating procedure.

c. Measure and record standpipe leakage and return flow. Confirm that total leakage limits are not exceeded.

d. Assure communication between control room and personnel stationed at RCP standpipe leakage drain line.

e. Countdown from 10 to 0

Start strip chart recorders at high speed;
Start Reactor Coolant Pump 2-2 in accordance with plant operating procedure.
After approximately 11 sec., reduce strip chart speed.

f. Run pump for two (2) minutes unless any above limits are exceeded.

g. Data assessment by B&W and Byron-Jackson representatives.

h. Following assessment of data, pump may be run for an additional five (5) minutes to allow for venting procedure requirements.

i. Follow above sequence on 2-1, 1-2 and 1-1.

j. Assessment of this data will determine whether any maintenance is required before high pressure operation is allowed.

3. Similar tests were repeated with system pressure at greater than 1300 psig before a final determination on the condition of the pumps was made.

All four reactor coolant pumps were run on 10/5/77 with the following results:

RCP 2-2 10/5/77 Run (2 min.):

Steam pressure 225 psig
2nd Seal cavity pressure 165 psig
3rd Seal cavity pressure 123.9 psig
Horizontal vibration 5 - 7.5 mils
Vertical vibration .25 mils

3rd Seal leakage plus seal return flow < .4gpm

After the 2-minute run, the pump was run for 10 minutes for system venting. About 30 seconds before the pump was shutdown, there was a step increase in vertical vibration to 2.5 mils. The pump was run again on 10/6/77 for 10 minutes to check out this phenemenon. The vertical vibration was again .25 mils until about 5 seconds before shutdown, when it increased to 2.5 mils. To allow a longer run time, 2-1 and 2-2 pumps were run together for 10 minutes, then 2-2 was run alone for 10 minutes. The vertical vibration stayed at .25 mils for the entire run. This was monitored during pump runs during plant heat up. It should be noted that the step increase in vertical vibration was later assessed to be spurious instrument noise as a result of a loose connector on an instrument line. After the connector was tightened, vertical vibration remained less than .25 mils peak-to-peak amplitude.

RCP 2-1

Steam pressure 225 psig
2nd Seal cavity pressure 132 psig
3rd Seal cavity pressure 70 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow < .4 gpm

RCP 1-2

System pressure 225 psig
2nd Seal cavity pressure 40.29 psig
3rd Seal cavity pressure 81.3 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow < .4 gpm

RCP 1-1

System pressure 225 psig
2nd Seal cavity pressure 77.98 psig
3rd Seal cavity pressure 89.27 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow < .4 gpm

The apparent discrepancy on seal cavity pressures on 1-1 and 1-2 was checked on 10/6/77 by installing pressure gauges at the pressure transmitters. The gauges read as follows:

1-1:

2nd Seal Cavity Pressure	- 184 psig
3rd Seal Cavity Pressure	- 111 psig

1-2:

2nd Seal Cavity Pressure	- 184 psig
3rd Seal Cavity Pressure	- 112 psig

The readings indicate the seals are staging properly.

Based on the above performance, B&W saw no concern which would justify maintenance at the time.

By 10/13/77 all four reactor coolant pumps had been run at a system pressure greater than 1300 psig.

RC Pumps 2-1 and 2-2 have continued to run from the initial cold pump starts. Below is a typical line of data from each pump.

<u>RCP 2-1</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1034 psig
3rd Seal Cavity Pressure	- 500 psig
Horizontal Vibration	- 3 mils

<u>RCP 2-2</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1075 psig
3rd Seal Cavity Pressure	- 588 psig
Horizontal Vibration	- 3.5 mils

<u>RCP 1-1</u>

Steam Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1056 psig
3rd Seal Cavity Pressure	- 540 psig
Horizontal Vibration	- 4 mils

<u>RCP 1-2</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 920 psig
3rd Seal Cavity Pressure	- 520 psig
Horizontal Vibration	- 3 mils

Based on the above data, B&W felt that all four pumps were in good operating condition and require nothing more at this time than periodic monitoring.

B&W has reviewed the results of the operational checks and has concluded that no detectable damage has occurred to the pump components. B&W considers the reactor coolant pumps to be serviceable for sustained full operational conditions with no requirements for maintenance.

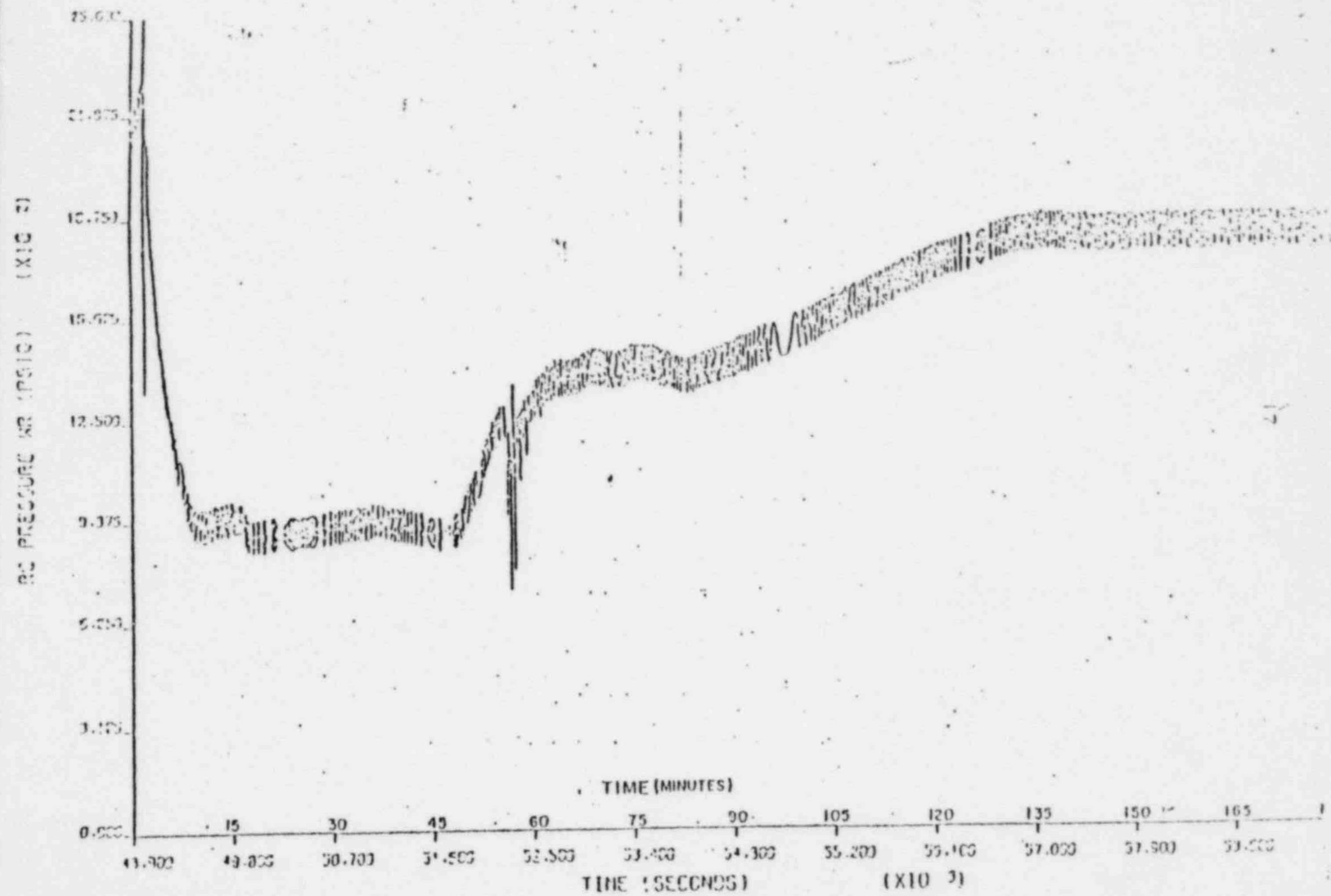
A more detailed analysis was completed to assess the core thermal conditions during the September 24 depressurization event at Davis-Besse Unit 1. Core conditions were analyzed to (1) determine if steam was produced in the core, (2) determine the maximum internal fuel rod pressure during the transient, and (3) determine if maximum lift force exceeded the limit.

Figure 4-5 shows transient thermal conditions as monitored by the reactimeter. The system pressure is measured at the pressure tap, which is approximately 65 feet above the top of the core. The RC pressure at the top of the core is approximately 50 psi higher than the measured pressure because of unrecoverable and elevation pressure losses. As shown in Figure 4-6, the predicted core coolant temperature is slightly higher than the minimum saturation temperature (based upon measured pressure); however, there is some uncertainty in both the measurement and the prediction. Therefore, it is possible that some vapor bubble formation (steam bubbles in water) could have occurred within the core. An examination of the reactimeter data (Figure 4-7) indicates that the RCS pressure level was near the saturation pressure for less than one hour and that during this time period the pressure oscillated with a variation of $\pm$ 50 psi. Therefore, the maximum time period during which the core could have been subjected to bubbly flow was less than one hour. If bubbles were formed during this period, the formation would be in the liquid as well as on the surface, as opposed to formation from a hot surface. With the temperatures, time duration, and type of formation, no significant effect on the components would be predicted.

Prior to the depressurization event the reactor had been operating at 15% power for approximately one week. Immediately prior to reactor trip the power level was 9% of rated power. The core burnup was 1 EFPD, therefore no significant fission gas production had occurred and none was released. During the 60-minute time period in which the indicated RCS pressure was estimated to vary from 900 to 1000 psia at the top of the core, the average coolant temperature was less than 540° F and no significant heat generation occurred in the fuel. An initial evaluation had predicted tensile stresses in the cladding based upon a maximum pressure differential across the cladding of 200 to 300 psi. This evaluation had been based upon a BOL TAFY analysis with an arbitrary safety factor added to ensure that actual conditions would be bounded by the prediction. A more recent analysis, again using TAFY, has resulted in a predicted maximum internal fuel rod pressure of 1000 psia. This analysis considered as-built fuel properties and hot, near zero power conditions at a coolant average temperature of 540° F. On the basis of this analysis it is concluded that the fuel rod cladding was not subjected to any significant level of tensile stress during the subject depressurization event.

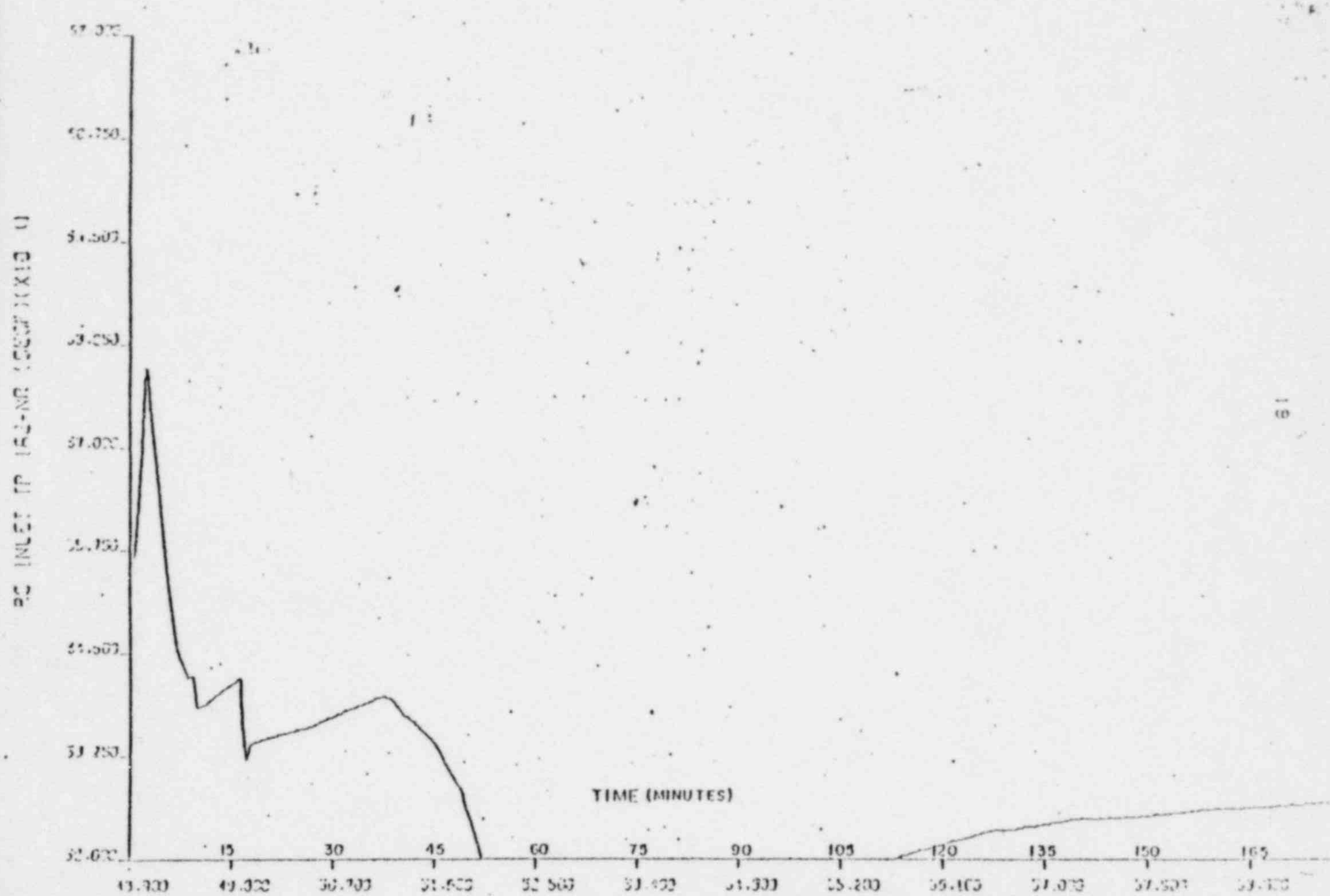
Because the cladding was not subjected to a large, long term tensile stress, no significant long term effects on the cladding resulted. The tensile stresses which could have occurred would have little effect on the cladding due to the small stress level and the short duration of the tensile stress.

Assuming a coolant temperature of 537 F and 150 X 10^6 lb/min system flow (per Figures 4-8 and 4-9), the net lift force will be less than 375 lb. The maximum allowable lift force is 472 lb. Therefore, we conclude that fuel assembly lift-off did not occur.



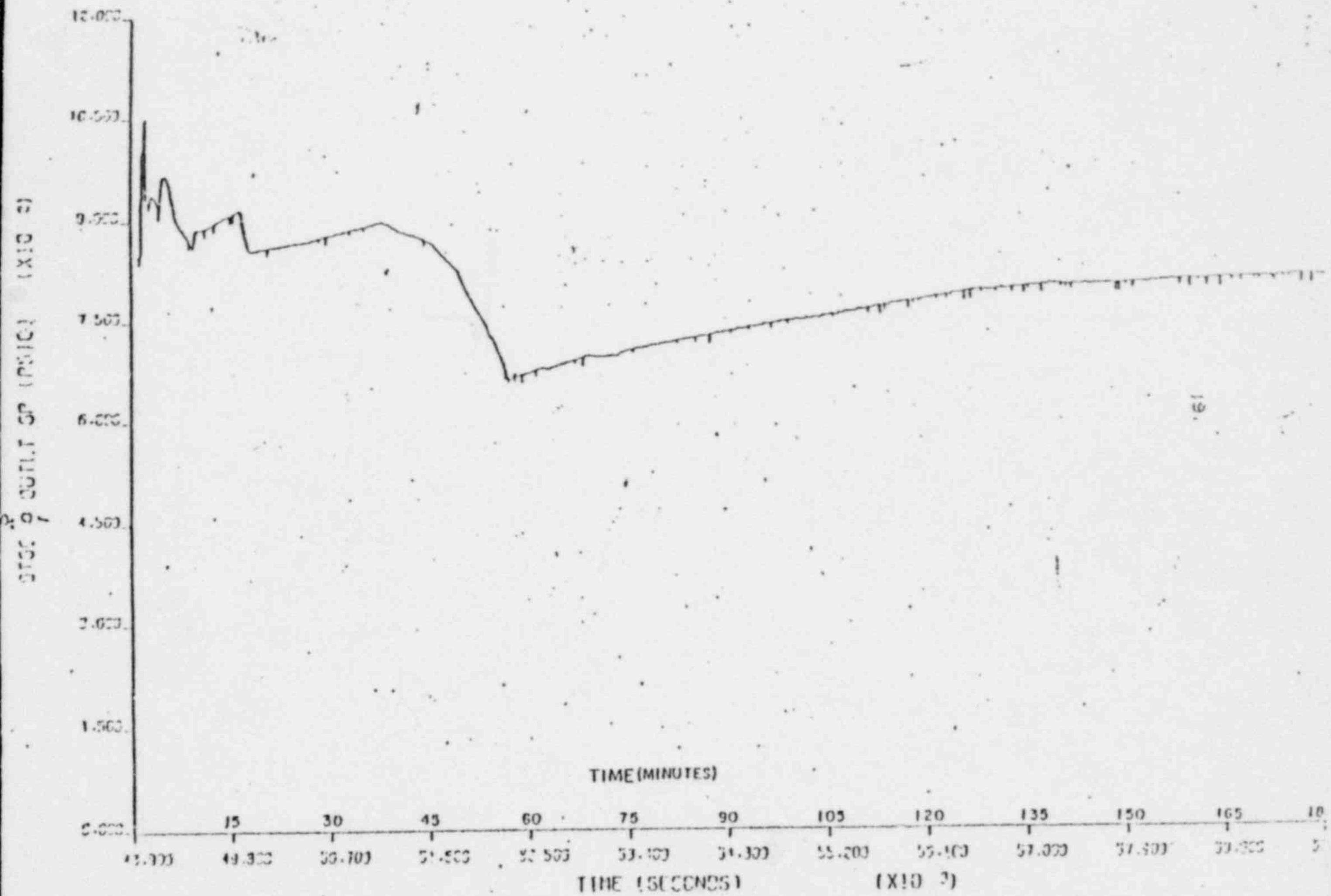
REACTIMETER PLOT TSN=71

FIGURE 4-1



REACTIMETER PLOT TSN=71

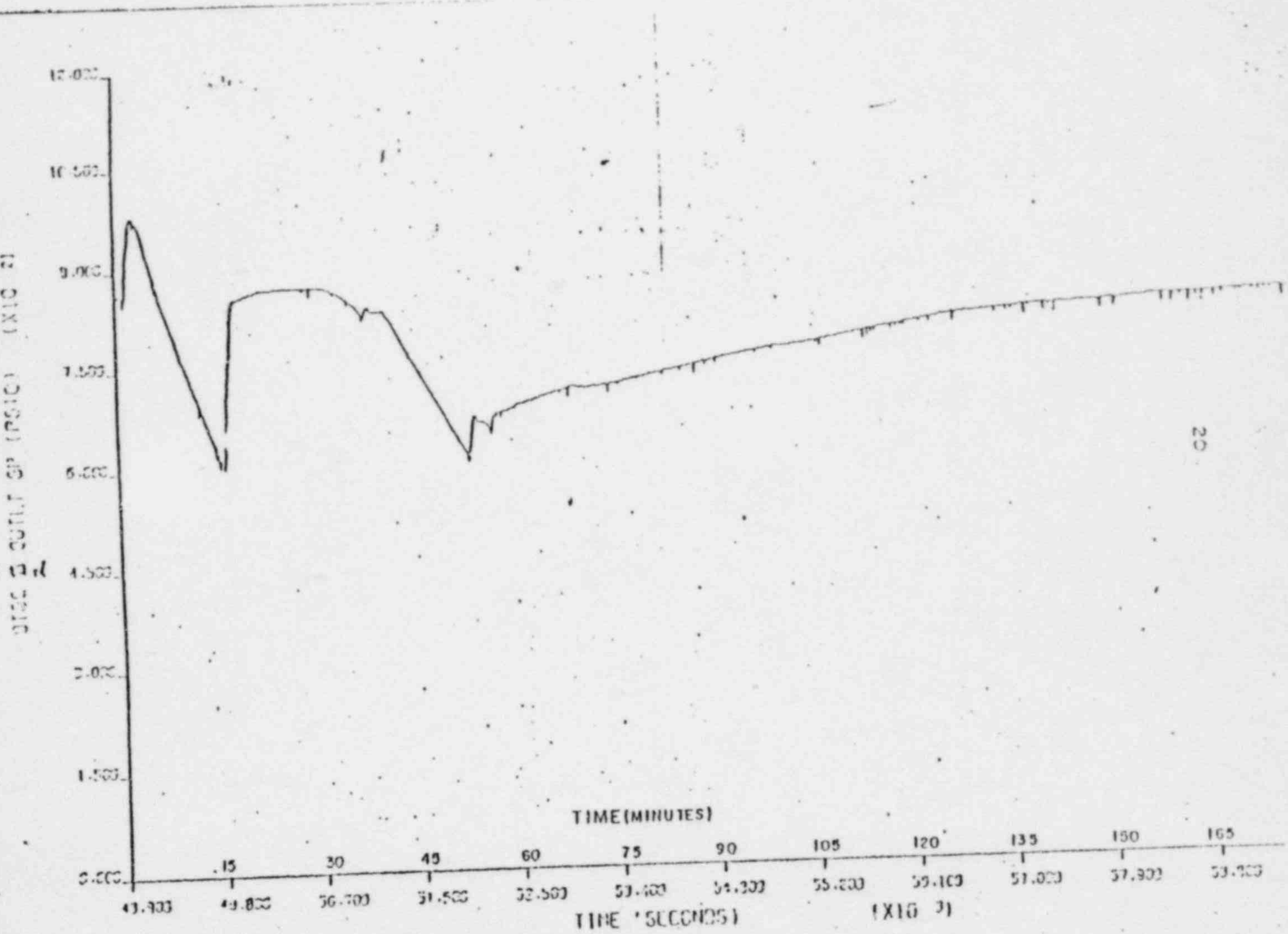
FIGURE 4-2



REACTIMETER PLOT TSN=71

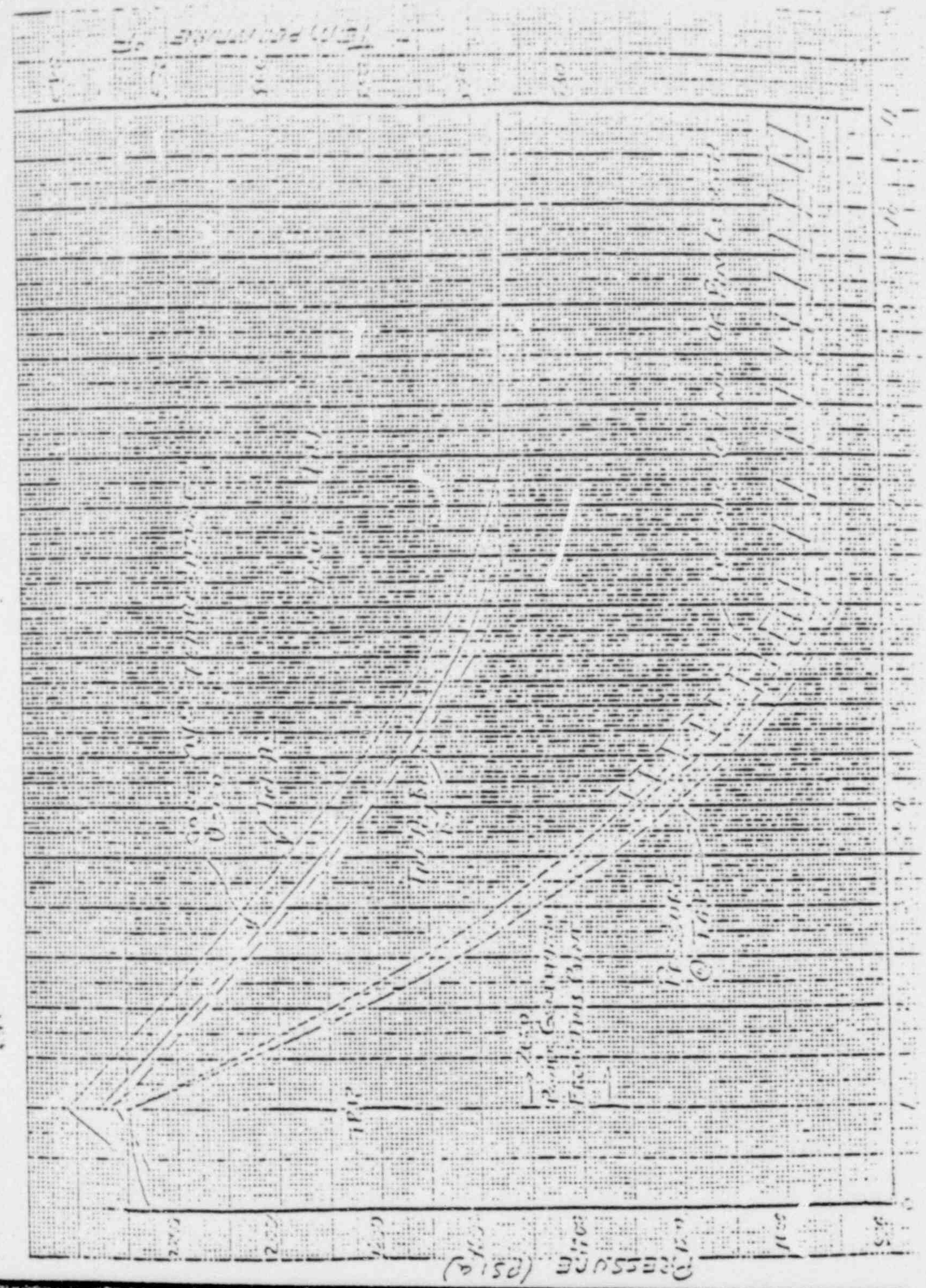
FIGURE 4-3

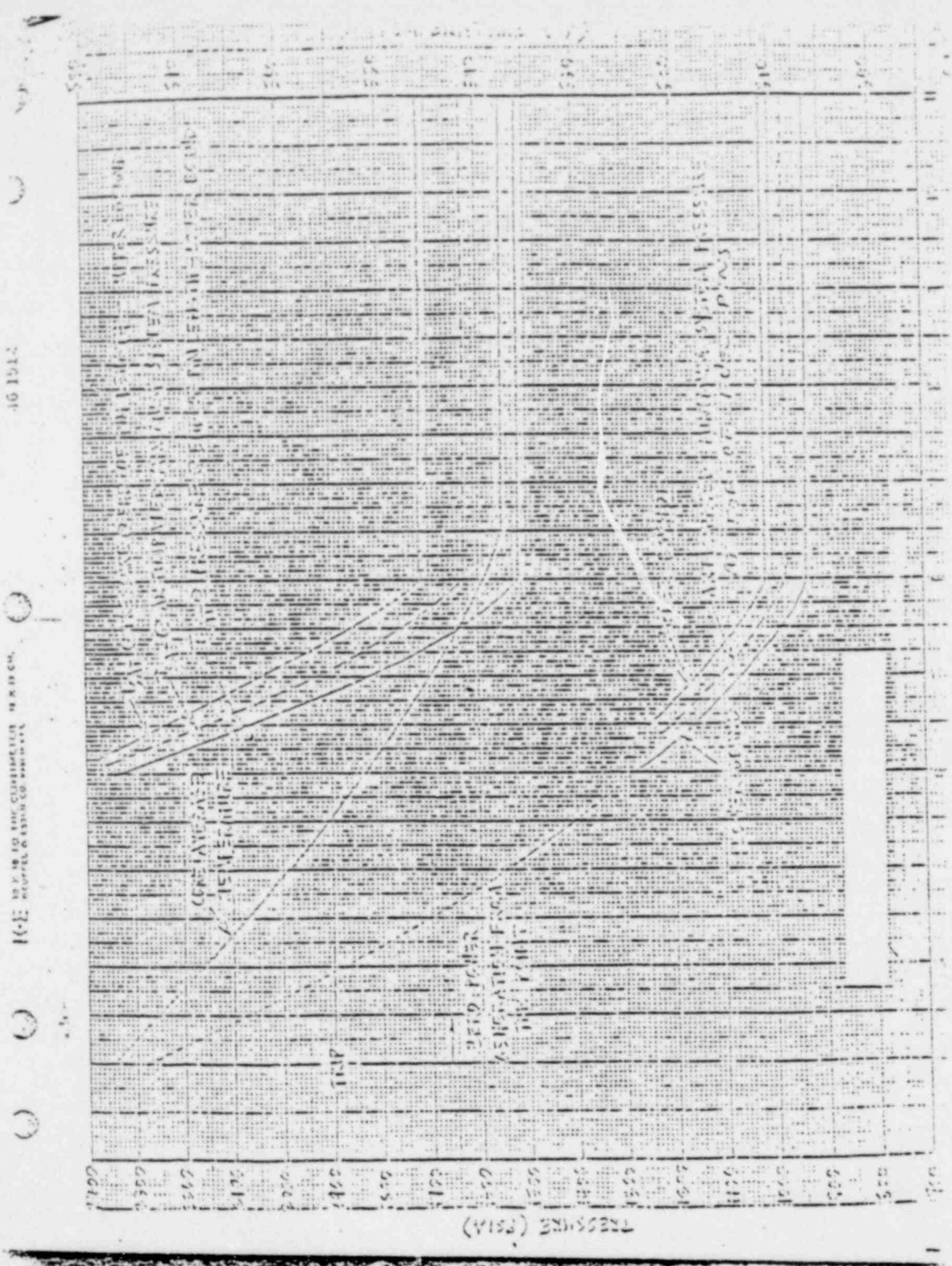
20

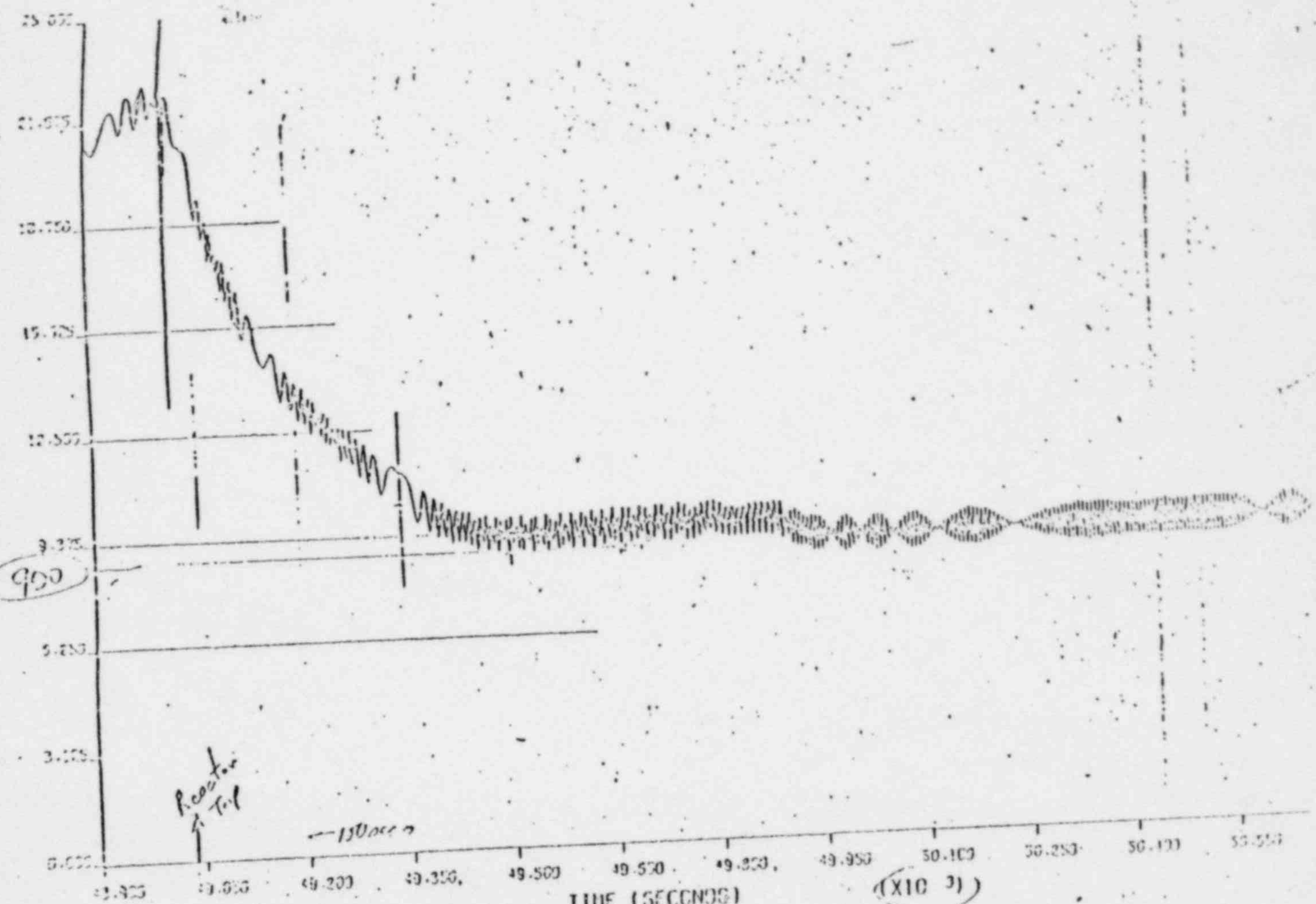


REACTIMETER PLOT TSN=71

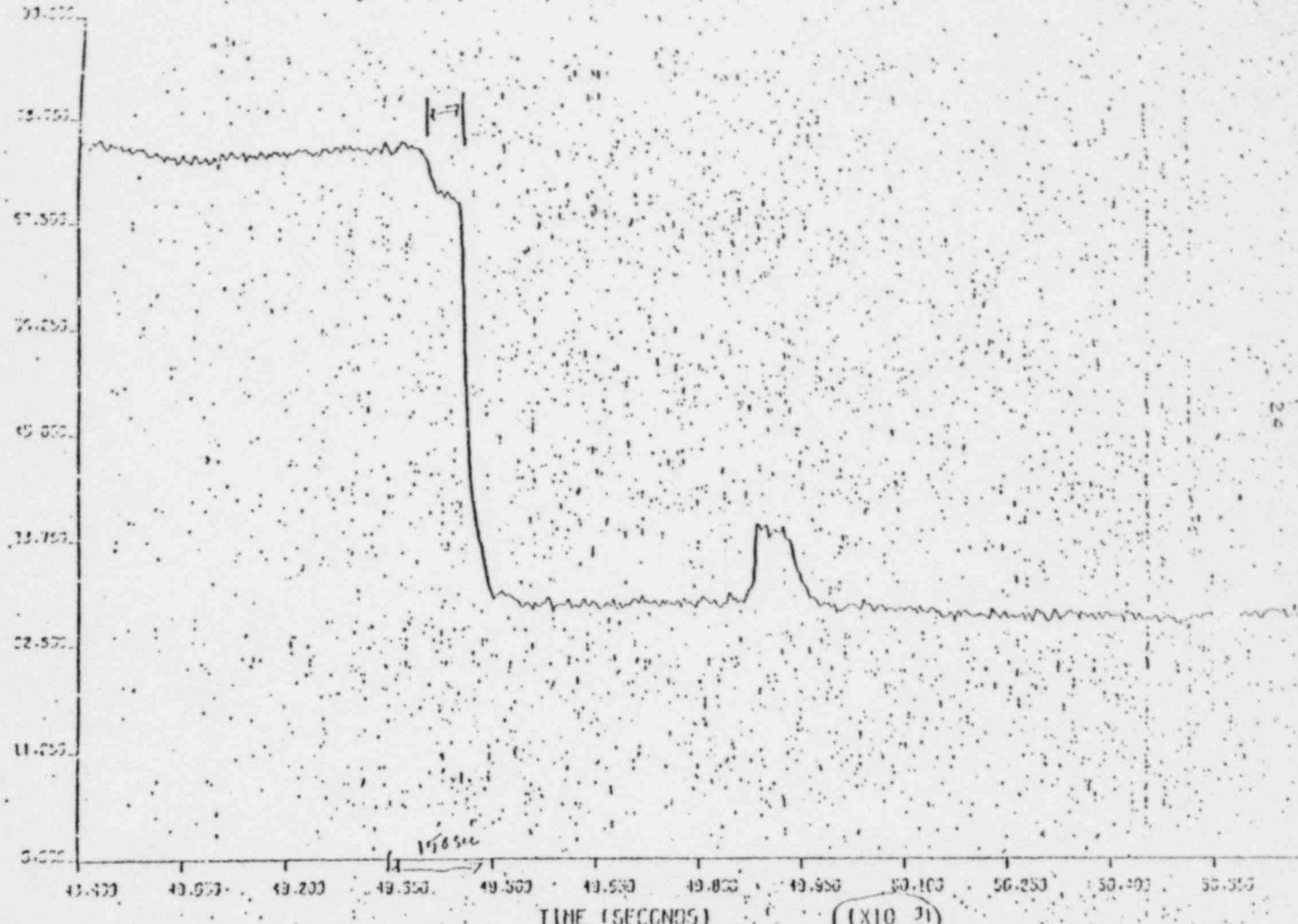
FIGURE 4-4





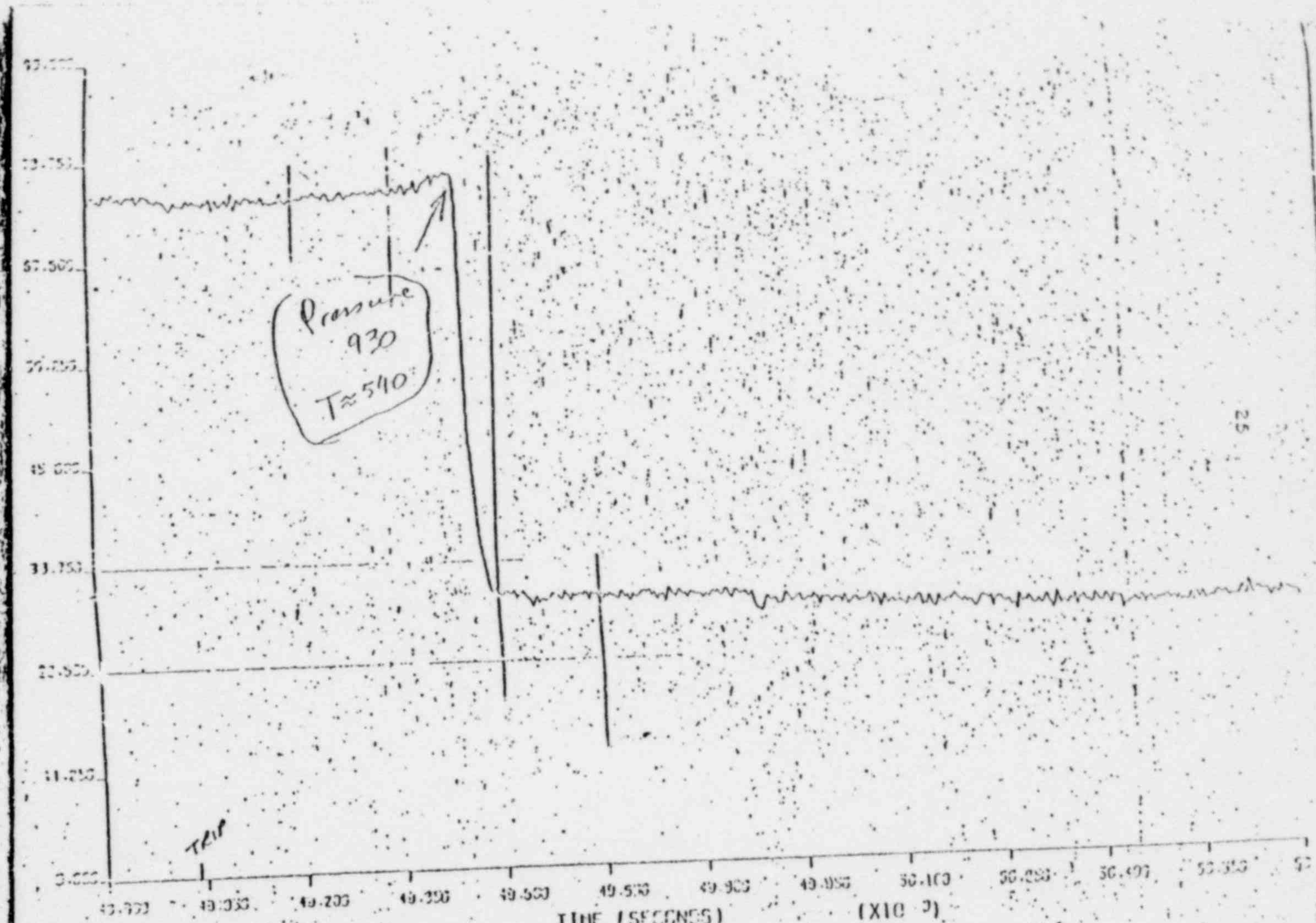


REACTIMETER PLOT TSN=71



REACTIMETER PLOT TSN=71

FIGURE 4-8



REACTIMETER PLOT TSN=71

FIGURE 4-9

5. EQUIPMENT DAMAGE, CLEANUP AND REPAIR

A. Entry and Cleanup

Prior to entering containment, air samples were collected at RE5030 (containment air monitor) for radioactive noble gases, particulates, iodines, and tritium; no airborne radioactive materials were detected. When containment was first entered at 0550 on September 25, 1977, to determine the levels of contamination, dirt was found on the walkways on elevation 565' and 585' in the east side of containment, and on 545' elevation the floor was completely covered with dirt which was washed down during the period when steam was being released from the quench tank and condensing on containment structures. The dirt was contaminated with activation products of Cr-51, W-187, Co-58, Zn-97, and Na-24 which were present in the reactor coolant system. Smears of the dirt indicated levels up to 40,000 dpm/100cm^2.

Decontamination was accomplished by shoveling gross amounts of dirt into drums, and vacuum sweeping the remainder. The level of contamination in walkways was reduced to meet clean area limits. Air samples collected during the decontamination work verified that contamination did not become airborne.

The outer surface of steam generator 1-2 was inspected in the region where the metal reflective insulation was blown off. Boric acid stains were observed on the outer surface of steam generator 1-2; however, these minute quantities do not present any concern since the temperature of these surfaces are on the order of 500° F.

B. Equipment Damage

The pressurizer quench tank rupture disc ruptured from high pressure in the quench tank. The steam from the pressurizer quench tank vent damaged metal reflective insulation on the lower part of No. 2 steam generator. A ventilating duct above the quench tank was bent, and a ventilation louver had to be replaced. Several pressurizer heater cables were dampened from the moisture, causing low insulation resistance, and had to be dried out. Four cables were also found shorted to ground, but it is not known if the failures were a direct result of the incident. Two light fixtures and a combustion detector sensor in the quench tank area were also damaged.

Twenty-three (23) panels of reflective insulation were deformed, loosened or detached from the lower exterior of the steam generator. The panels, fabricated from thin stainless steel sheets with air spaces between them, are approximately 36" x 30" x 4".

The panels are formed to the contour of the steam generator and attached to the exterior on a frame to support the weight. Buckles and clips fasten the panels together. Panels blown from the steam generator fell to the floor, piping and ventilation duct in the immediate vicinity. Some panels were repaired and reused; others had to be replaced. The damaged panels were intact but were bent.

C. Repairs

All damaged equipment was repaired or replaced. Instrumentation and equipment in the area was checked or tested for possible damage from the steam and water.

Twenty-three (23) panels of reflective insulation were replaced. The other affected panels were straightened, repositioned and reinstalled on the steam generator.

All essential and automatically-controlled pressurizer heaters were returned to service. The wet pressurizer heater cables were baked, heated or air dried to restore insulation resistance to vendor recommended values. Only two of the four cables shorted to ground were replaced with spares. The other two are on order.

A new rupture disc was installed on the pressurizer quench tank.

The deformed ventilation duct was straightened and a new louver was installed in the duct.

The damaged light fixture and combustion detector were replaced.

6. SYSTEMS/EQUIPMENT MODIFICATION AND TESTING

A. SFRCS

The Davis-Besse Instrument and Control (I&C) Group has tested logic channels 2 and 4 (channel 2) of the SFRCS, since it was indicated that the closure of SP7A (start-up feedwater valves) led to the sequence of events on 9/24/77. Logic channels 2 and 4 are the only SFRCS channels that actuate SP7A.

On 9/26/77, Maintenance Work Order (MWO) IC-622-77 was written to check the main steam line pressure switches PS 3687A through PS 3687H. A calibration check was completed on 9/27/77. All pressure switches actuated within ±2 psig of the 612 psig set-points. I&C personnel had nothing to report from the visual inspection.

On 9/27/77, MWO IC-636-77 was written to investigate the remaining inputs to the SFRCS. Pressure differential switches 2686C, 2686D, 2685A and 2685B were tested per ST 5031.14, Section 6.3. The setpoint of the pressure differential switches tested ranged from 176 psig to 187 psig, the setpoint being 177 ±20 psig.

The steam generator level inputs to the SFRCS were tested per ST 5031.14, Section 6.4. Again, logic channels 2 and 4 were tested. All bistables tripped at the desired setpoints. The desired trip setting is .509 ±.013 volts and the range of voltages for the bistables tested were from .5054 volts to .509 volts. In addition, the level transmitter calibration was checked per ST 5031.16. I&C tested for any non-linearities between transmitter input and output, especially at the lower ranges. LT-SP9A8, LT-SP9A9, LT-SP9B6, and LT-SP9B7 were well within the acceptable limits as specified by ST 5031.16 and no non-linearities were observed.

The inputs to the SFRCS from the loss of 4 reactor coolant pumps were not tested since this input actuates auxiliary feedwater only. This input does not affect the feedwater valves or main steam isolation valves.

In addition to testing all the input devices, I&C checked C5792. This is the cabinet for logic channels 2 and 4. All inputs and outputs were normal for existing plant conditions. I&C checked mechanical connections on the input and output buffers, and induced mechanical vibration on the input buffers, output buffers, main logic panels, and output relays without any system effect. The main logic panels were heated slightly with a heat lamp and slowly cooled to check for thermal variations, but this had no effect on the system.

On September 29, I&C completed their check of SFRCS terminations. The following are the results of that check:

1. Screws on TB37 (yellow & blue) were tightened 1/2 of a turn. This is an input to the Sorenson 15 volt logic supply for C5792.

2. In C5721 (Feedwater Panel) one loose screw was found on 21TB11 Terminal 17 (left side of TB). This screw required little movement to thoroughly tighten. This is a main steam pressure switch input to logic channel 2.

3. In C5721, 21TB27 had 3 loose screws. Terminal 17 (right side of Terminal Board) had to be tightened 1 full turn. This is a main steam pressure switch input to logic channel 3.

   Terminal 18 (right side of Terminal Board) had to be tightened 1/2 a turn. This is a pressure differential switch input to the SFRCS. Logic channel 3 Terminal 4 (left side of TB) had to be tightened slightly. This is a main steam pressure switch input to the SFRCS.

On September 30, HIS 4870 A and C were tightened to their mounting. These are stacked switches. The switch units themselves were secure, but the entire package was loose on the mounting. This switch unit being loose would probably not have affected system operation. Temporary jumpers were installed to prevent an inadvertent main steam isolation valve closure during SFRCS checkout.

On October 6, 1977, the Steam Generator level instrumentation was checked out. I&C was specifically looking for noise spikes that could have caused an erroneous trip. All analog inputs and outputs only had a 20 MV (typical) AC noise. DC signals appeared "clean".

On October 8, 1977, eight 6 channel chart recorders were patched into the system for continuous monitoring. The recorders were connected per the attached sheets. The system was then checked out for operability. Pressure differential and Steam Generator low level trips were tested. Since the SFRCS was blocked due to low steam pressure, pressure switch trips were initiated and the input to the logic was verified by a voltmeter reading. These pressure switch inputs will be further tested during the SFRCS monthly, ST 5031.14, Section 6.2, at a later date. Connecting the recorders has indicated no effect on system operability.

LOGIC CHANNEL 1 SFRCS TEST CONNECTIONS

INPUT	CONNECT COMMON TO BUFFER	CONNECT COMMON TO TEST POINT	CONNECT SIGNAL LEAD TO BUFFER	CONNECT SIGNAL LEAD TO TEST POINT	RECORDER	CHANNEL
PS3689A	1-1	TP4	1-1	TP5	9.1.48	1
PS3689B	2-1	TP2	1-1	TP7	9.1.48	2
PS3689C	2-2	TP2	1-1	TP9	9.1.46	9
PS3689D	1-2	TP4	1-2	TP5	9.1.48	4
PD2686A	1-3	TP4	1-3	TP7	9.1.48	5
PD2685C	2-3	TP2	1-3	TP9	9.1.48	6
LT SP9B6	1-4	TP4	1-4	TP5	9.1.46	7
LT SP9A6	2-4	TP2	1-4	TP7	9.1.46	8
15 V. Power Supply Output	1-5	TP2	1-5	TP10	9.1.48	3
P681	2-7	TP2	2-7	TP10	9.1.46	10
P671	2-6	TP2	2-7	TP16	9.1.46	11
LS86	1-6	TP2	1-6	TP10	9.1.49	12

LOGIC CHANNEL I SFRCS TEST CONNECTIONS

	Connect Common To		Connect Signal Lead To			
[illegible]	BUFFER	TEST POINT	BUFFER	TEST POINT	RECORDER	CHANNEL
[illegible]57A	1-1	TP4	1-1	TP5	9.1.44	1
[illegible]57B	2-1	TP2	1-1	TP7	9.1.44	2
[illegible]57C	2-2	TP2	1-1	TP9	9.1.41	9
[illegible]57D	1-2	TP4	1-2	TP5	9.1.44	4
[illegible]2683A	1-3	TP4	1-3	TP7	9.1.44	5
[illegible]2686C	2-3	TP2	1-3	TP9	9.1.44	6
[illegible] SP9B6	1-4	TP4	1-4	TP5	9.1.41	7
[illegible] SP9A6	2-4	TP2	1-4	TP7	9.1.41	8
[illegible] V. Power [illegible]pply Output	1-5	TP2	1-5	TP10	9.1.44	3
[illegible]80	2-7	TP2	2-7	TP10	9.1.41	10
[illegible]72	2-6	TP2	2-7	TP16	9.1.41	11
[illegible]96	1-6	TP2	1-6	TP10	9.1.41	12

LOGIC CHANNEL 3 SFRCS TEST CONNECTIONS

	CONNECT COMMON TO		CONNECT SIGNAL LEAD TO			
INPUT	BUFFER	TEST POINT	BUFFER	TEST POINT	RECORDER	CHANNEL
PS3689E	1-10	TP4	1-10	TP5	9.1.47	13
PS3689F	2-10	TP2	1-10	TP7	9.1.47	14
PS3689G	2-11	TP2	1-10	TP9	9.1.45	21
PS3689H	1-11	TP4	1-11	TP5	9.1.47	16
PDS2686B	1-12	TP4	1-12	TP7	9.1.47	17
PDS2685D	2-12	TP2	1-12	TP9	9.1.47	18
LT SP9B9	1-14	TP4	1-13	TP5	9.1.45	19
LT SP9A7	2-13	TP2	1-13	TP7	9.1.45	20
15 V. Power Supply Output	1-14	TP2	1-14	TP10	9.1.47	15
P681	2-16	TP2	2-16	TP10	9.1.45	22
P671	2-16	TP2	2-16	TP16	9.1.45	23
LS86	1-15	TP2	1=15	TP10	9.1.45	24

LOGIC CHANNEL 4 SFRCS TEST CONNECTIONS

	CONNECT COMMON TO		CONNECT SIGNAL LEAD TO			
[illegible]	BUFFER	TEST POINT	BUFFER	TEST POINT	RECORDER	CHANNEL
687E	1-10	TP4	1-10	TP5	9.1.43	13
687F	2-10	TP2	1-10	TP7	9.1.43	14
687G	2-11	TP2	1-10	TP9	060404	21
687H	1-11	TP4	1-11	TP5	9.1.43	16
2685B	1-12	TP4	1-12	TP7	9.1.43	17
S2686D	2-12	TP2	1-12	TP9	9.1.43	18
SP9B7	1-13	TP4	1-13	TP5	060404	19
SP9A9	2-13	TP2	1-13	TP7	060404	20
5 V. Power upply Output	1-14	TP2	1-14	TP10	9.1.43	15
680	2-16	TP2	2-16	TP10	060404	22
672	2-15	TP2	2-16	TP16	060404	23
296	1-15	TP2	1-15	TP10	060404	24

On 10/23/77, the SFRCS again tripped from a spurious signal. The Startup Feedwater Valve on steam generator No. 2 went closed. This ultimately resulted in a valid Steam Generator low level trip input to the SFRCS and the system functioned as intended.

This was the first spurious trip received since the chart recorders had been connected to the SFRCS. All information on the charts could be explained except for a problem on SFRCS logic Channel 4 computer alarm, P680. This particular channel on the recorder was intermittently failing, giving spurious trip indications. Of the 48 total chart recorder channels, this was the only one that had failed.

I&C Technicians "checked out" the bad recorder channel for operation. They found that the channel was sensitive to any mechanical vibration, it did respond to a given input, and that the pens were slightly misaligned. From all of the information gathered it was concluded that the indication on the bad recorder channel was an input from the SFRCS.

The logic point under question then was the computer point ("P680" Low Main Steam Pressure Trip). Examining other charts indicated no change in the input to SFRCS logic Channel 4. Thus it was concluded the problem was internal to the system. In examining the logic control diagram, it was determined 3 IC "chips", 2 input buffers and associated wiring could have caused the fault. I&C personnel replaced all of the above equipment, with the exception of the interconnecting wiring. The wiring and buffer connections were visually inspected, and no faults were observed. A functional logic test was performed and the system responded satisfactorily.

Power Engineering had contacted Consolidated Controls Corporation, the manufacturer, and their representative was on site the morning of 10/26/77. The manufacturer also recommended changing the same equipment that TECo I&C personnel had changed.

The manufacturer performed a response time check on both input buffers in question. The response time test showed no defects. TECo I&C personnel continued to monitor one of the two input buffers in a test set. Failure of one input buffer did occur on the test set, which indicates that this was the cause of the half trip.

The manufacturer's representative also took a look at the logic system with an oscilloscope. He was looking for any erratic, noisy points, but everything tested appeared to be trouble free. The two input buffers will remain with TECo for further test and evaluation, while the 3 IC chips were returned to the manufacturer for evaluation.

The manufacturer's representative on 10/27/77 compiled a list of additional points they want monitored. TECo I&C personnel are assisting to connect up the recorders.

After the 10/22/77 event, a study was also conducted to see if any single 120 VAC or 125 V DC fault induced voltage dip could have caused the one-half trip on both MSIV's and closed the SG-2 SU control valve. This study revealed that no single fault on these power supplies could have caused this problem.

The following changes have been made to the design of the SFRCS since the September 24, 1977 incident:

1. Annunciator windows have been added where computer alarms presently exist for:

    a. Steam Generator Level Half/Full Trip for both Channels 1 & 2

    b. Main Feedwater DP Half/Full Trip for both Channels 1 & 2

    c. Loss of 4 Reactor Coolant Pump Trip

2. A new annunciator and computer alarm has been added for a SFRCS Full Trip.

3. The resetting of all SFRCS related alarm will be delayed long enough to allow the computer to record the event.

These changes will be made as soon as possible.

B. Auxiliary Feedpump Turbine Governor

Before describing the modifications made to the auxiliary feedpump turbine (AFPT) governor, the governor action which resulted in the binding will be described. Figure 6-1 is a drawing of the Woodward Governor PG-PL speed setting mechanism, showing the governor in the bound up condition. The sequence of events creating this condition is as follows:

1. When the Bodine motor was at a minimum speed setting, the speed setting shaft nut was fully to the left. The link raised the collar, contacting the base speed setting nut, raising it and the "T"-bar to an idle condition. The pivot bearing would be contacting the floating lever.

2. Because the governor is not rotating, the speed setting servo remains in a fixed position at idle (as shown). It cannot move until oil pressure is available.

3. The thumbscrew is contacting the low speed stop pin.

4. As the Bodine speed setting motor is rotated toward high speed, the following events occur:

   4.1 The speed setting shaft nut moves towards the high speed stop pin.

   4.2 The link allows the collar to move downward.

   4.3 The collar moving downward, allows the base speed setting nut and "T"-bar assembly to move downward.

   4.4 The floating lever is fixed at the speed setting servo piston end.

   4.5 The low speed stop pin end of the link pushes down on the thumbscrew, which pushes down on the speed setting pilot valve until the dashpot land contacts the dashpot plug.

   4.6 Because the floating lever is now fixed on both ends it stops moving.

   4.7 The "T"-bar continues downward, following the collar. The pivot bearing leaves the floating lever. The "T"-bar continues downward until the retainer screw contacts the floating lever.

   4.8 The collar separates from the base speed setting nut and continues downward until the stop pin in the speed shaft contacts the stop pin in the speed setting shaft nut.

4.9 Because the Bodine motor continues to rotate the manual speed setting knob, slipping the clutch, a torque is placed on the speed setting shaft nut, link and colla This torque against the "T"-bar causes friction that locks the "T"-bar in place.

5. When the turbine is started, the speed setting servo piston moves downward with increasing oil flow, increasing the speed setting of the governor. When the floating level contacts the pivot bearing, the speed setting pilot valve begins to raise.

6. When the pilot valve control land covers the metering port, the speed setting servo piston stops moving.

7. Because the torque is still present on the speed setting shaft, the "T"-bar is bound up, and the governor is at 2200-2600 rpm.

8. When the Bodine speed setting motor is backed off from the stop, the "T"-bar falls down to its high speed stop, dropping the pivot bearing. The pilot valve moves downward, increasing oil flow to the speed setting servo until the high speed condition is reached.

9. Any changes in speed setting shaft position are now normally followed by the "T"-bar, pivot bearing, pilot valve, and speed setting servo piston.

When the AFPT governors arrived at the Woodward Governor Company factory, one of the governors was placed on the test stand. While observing the operation of the speed setting linkage, it became evident that a simple link from the speed setting pilot valve (plunger) to the floating lever would allow removal of the bellows coupling spring, low speed pin, "C" link and dashpot plug in the speed setting pilot valve sleeve (see Figure 2). This would allow the speed setting pilot valve to overtravel when the motor was set in a high speed condition with the speed setting servo at the minimum position (see Figure 6-3).

The required parts were manufactured, the unneeded parts removed and the governors were reassembled. The governors were tested at the Woodward factory and the tests confirmed that the modifications did remove all possibility of the undesired binding of the governors. Surveillance testing at the station has also confirmed that the auxiliary feedpump turbine governors function properly.

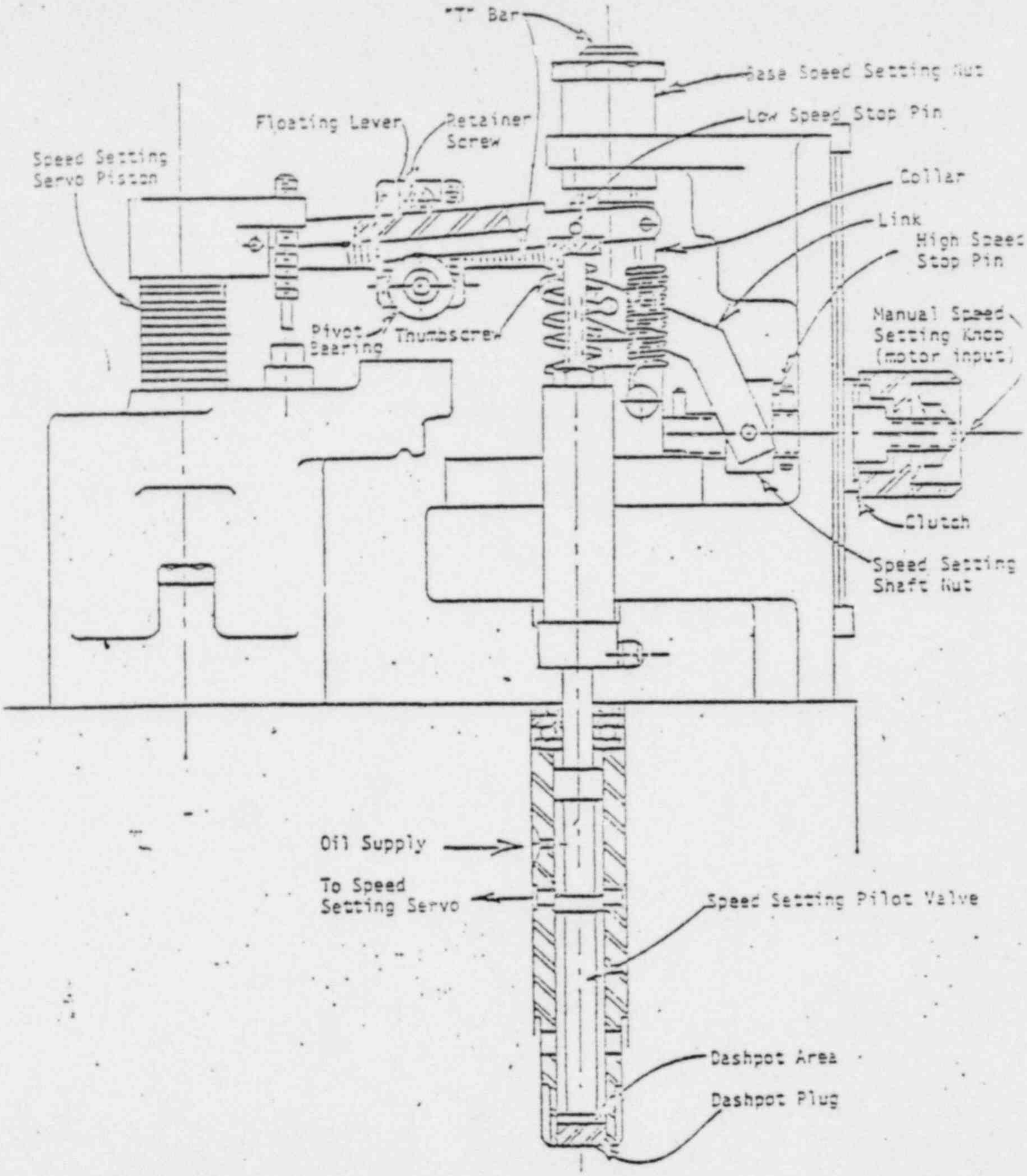

"T" Bar
Base Speed Setting Nut
Low Speed Stop Pin
Floating Lever
Retainer Screw
Speed Setting Servo Piston
Collar
Link
High Speed Stop Pin
Pivot Bearing
Thumbscrew
Manual Speed Setting Knob (motor input)
Clutch
Speed Setting Shaft Nut
Oil Supply
To Speed Setting Servo
Speed Setting Pilot Valve
Dashpot Area
Dashpot Plug

FIGURE 6-1

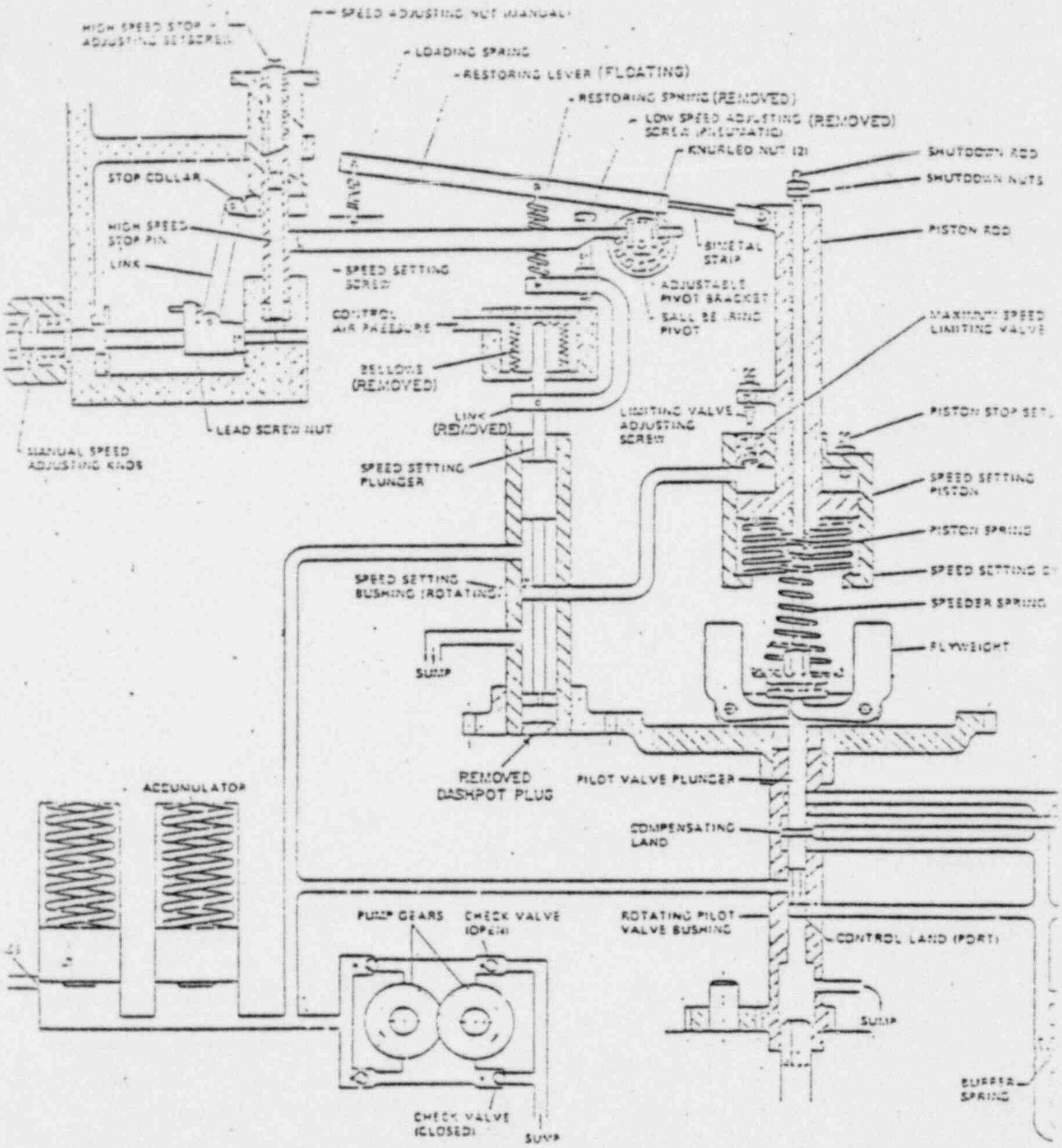

HIGH SPEED STOP ADJUSTING SETSCREW
SPEED ADJUSTING NUT (MANUAL)
LOADING SPRING
RESTORING LEVER (FLOATING)
RESTORING SPRING (REMOVED)
LOW SPEED ADJUSTING SCREW (PNEUMATIC) (REMOVED)
KNURLED NUT (2)
SHUTDOWN ROD
SHUTDOWN NUTS
STOP COLLAR
HIGH SPEED STOP PIN
LINK
SPEED SETTING SCREW
BIMETAL STRIP
PISTON ROD
ADJUSTABLE PIVOT BRACKET
BALL BEARING PIVOT
CONTROL AIR PRESSURE
MAXIMUM SPEED LIMITING VALVE
BELLOWS (REMOVED)
LEAD SCREW NUT
LINK (REMOVED)
LIMITING VALVE ADJUSTING SCREW
PISTON STOP SET
MANUAL SPEED ADJUSTING KNOB
SPEED SETTING PLUNGER
SPEED SETTING PISTON
PISTON SPRING
SPEED SETTING BUSHING (ROTATING)
SPEEDER SPRING
SUMP
FLYWEIGHT
REMOVED DASHPOT PLUG
PILOT VALVE PLUNGER
ACCUMULATOR
COMPENSATING LAND
PUMP GEARS
CHECK VALVE (OPEN)
ROTATING PILOT VALVE BUSHING
CONTROL LAND (PORT)
SUMP
BUFFER SPRING
CHECK VALVE (CLOSED)
SUMP

FIGURE 6-2

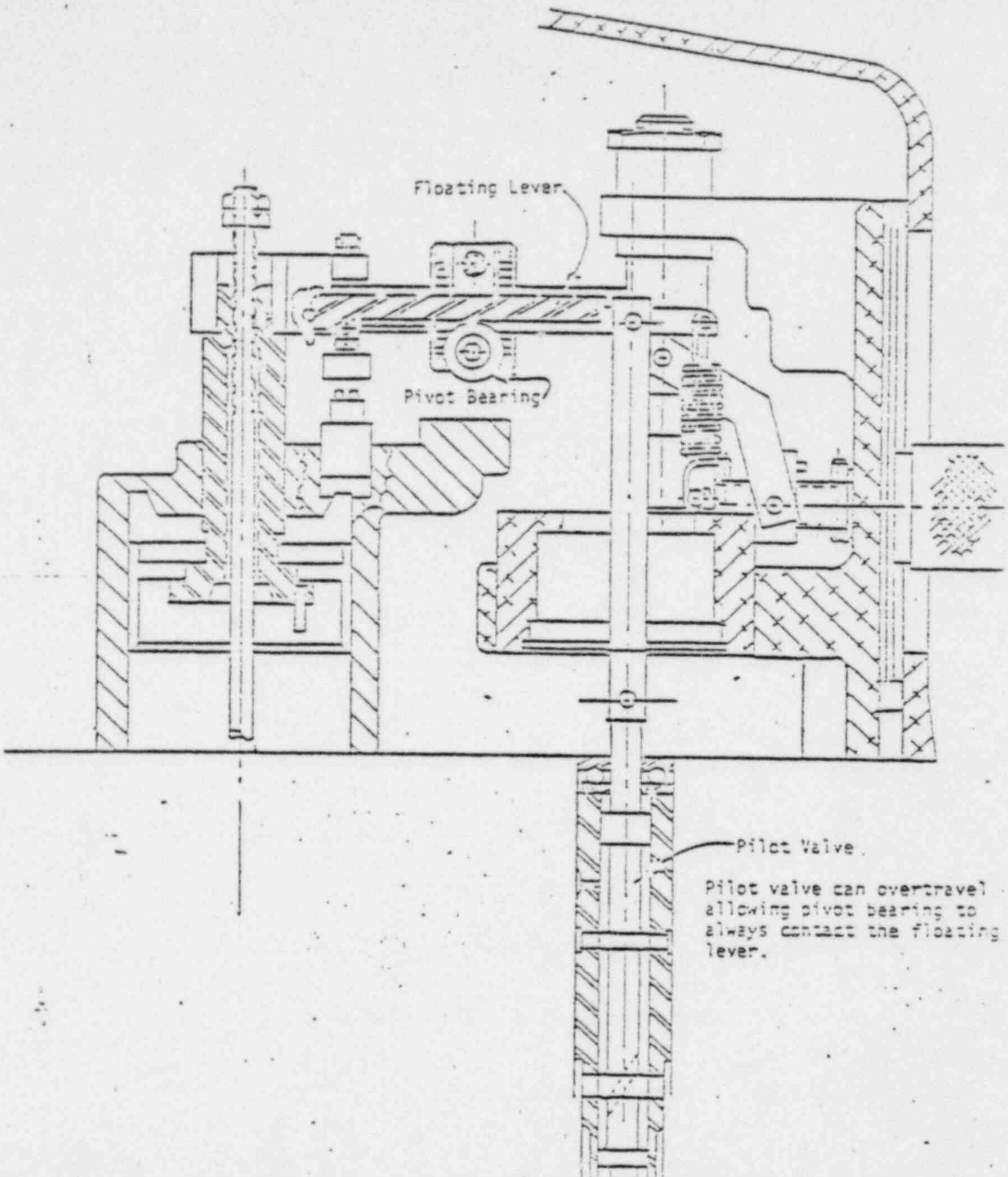

Floating Lever
Pivot Bearing
Pilot Valve
Pilot valve can overtravel allowing pivot bearing to always contact the floating lever.

FIGURE 6-3

C. Pressurizer Power Relief Valve

On September 28, 1977, the valve was completely disassembled. The main valve was found to be clean. The seats on the nozzle and main valve disc were lapped. The pilot valve was found stuck in the open position and it was thought that the pilot stem was bent so the pilot stem was replaced and the nozzle guide area was cleaned up to remove the marks from the galling of the foreign material. The valve was reassembled and on October 12, 1977, the valve was stroked six (6) times with a pressurizer pressure of approximately 600 psi. During this testing the pilot valve again stuck and the isolation valve had to be closed.

The valve was again disassembled and under closer observation it was found that the pilot valve stem was moving too far (3/8" vs 1/8" desired). It was also found that the clearances between the pilot stem and the nozzle guide were too small (.0005" vs desired minimum of .001"). The clearances were opened up and the stroke of the pilot was shortened by adjustment of solenoid position. The valve was tested again successfully by stroking it twelve (12) times on October 15, 1977, at a pressurizer pressure of approximately 900 psi and one time at a pressure of 2200 psi.

D. Relay/Fuse/Wiring Checks

Because of the missing relay in the pressurizer electromatic relief valve control circuit, an extensive review program of checking all other relay cabinets was performed. All relay cabinets in the plant were inspected for missing plug-in relays and fuses. A detailed review of drawings was made to determine the service of each missing item and its effect on plant operations. The one additional relay and ten fuses found missing were replaced. There were no essential functions affected by the additional missing relay and fuses. The missing fuses and relay were for generator iso phase bus control, alarm and indications; relay cabinets power supply and heater supply circuits; main feed pump turbine lube oil tank level indication; and reactor coolant pump component cooling water return valve control.

Neither the missing relay nor the fuses were controlled under the station jumper and lifted wire control procedure. This indicates the fuses and relay were removed by unknown persons after checkout and testing.

E. Other Actions

Following this incident a training program was developed and presented. This program was approximately eight (8) hours of instruction and discussion covering the events of this incident, including a detailed coverage of the transient and the actions taken by the operators, and a refresher training session covering the operation of the steam and feedwater rupture control system.

The training was presented to all in the operating shift crews, the management and staff level engineers and the QA/QC staff.

7. EXHIBITS

A. Event Chronology

B. Event Variables Plots

C. SFRCS Description

D. 10 CFR Part 21 Letter on Auxiliary Feedpump Turbine Governor

E. Historical Log

7A. Event Chronology

21:34:20 Startup Feedwater Valve to OTSG #2 went closed on a "½ trip" of the Steam and Feedwater Rupture Control System (SFRCS).

21:35:18 Received a complete SFRCS trip due to low level in OTSG #2.

21:35:23 Main Steam Isolation Valves went closed.

21:35:26-49 Pressurizer Power Relief Valve cycled 9 times before sticking open.

21:36:04 Auxiliary Feed Pump (AFP) #1 was feeding #1 Steam Generator (SG). AFP #2 did not come up to full speed (3600 rpm), and the discharge pressure was not sufficient to feed #2 SG.

21:36:07 Operator tripped the reactor.

21:37:17 Safety Features Actuation System Incident Levels 1 and 2 were initiated due to reactor coolant system pressure less than 1600 psi.

21:37:33 High Pressure Injection (HPI) Pump 1-2 was on and had normal flow.

21:37:49 HPI Pump 1-1 was on and had normal flow.

21:38:13 Re-established Reactor Coolant Makeup flow.

21:40:22 Containment Normal Sump Pump came on indicating the Quench Tank Rupture Disk had blown.

21:40:36 HPI Pumps were shutdown.

21:43:16 Auxiliary Boiler System was started and at normal conditions.

21:43:41 Tripped Reactor Coolant Pumps (RCP's) 1-1 and 2-2.

21:44:05 Re-established Reactor Coolant Letdown flow.

21:49:57 Put AFP #2 in hand and ran it up to speed (3600 rpm) and then lowered the speed.

21:58:00 Closed block valve to Pressurizer Power Relief Valve.

22:15:22 Started second Reactor Coolant Makeup Pump.

22:22:57 Started #2 HPI Pump.

22:27:24 Brought #2 Main Feed Pump back on with Auxiliary Boiler steam.

22:27:44 Shutdown #2 HPI Pump.

22:33:23 Shutdown #1 Reactor Coolant Makeup Pump.

22:43:54 Shutdown #1 and #2 AFP's.

45

EXHIBIT - B

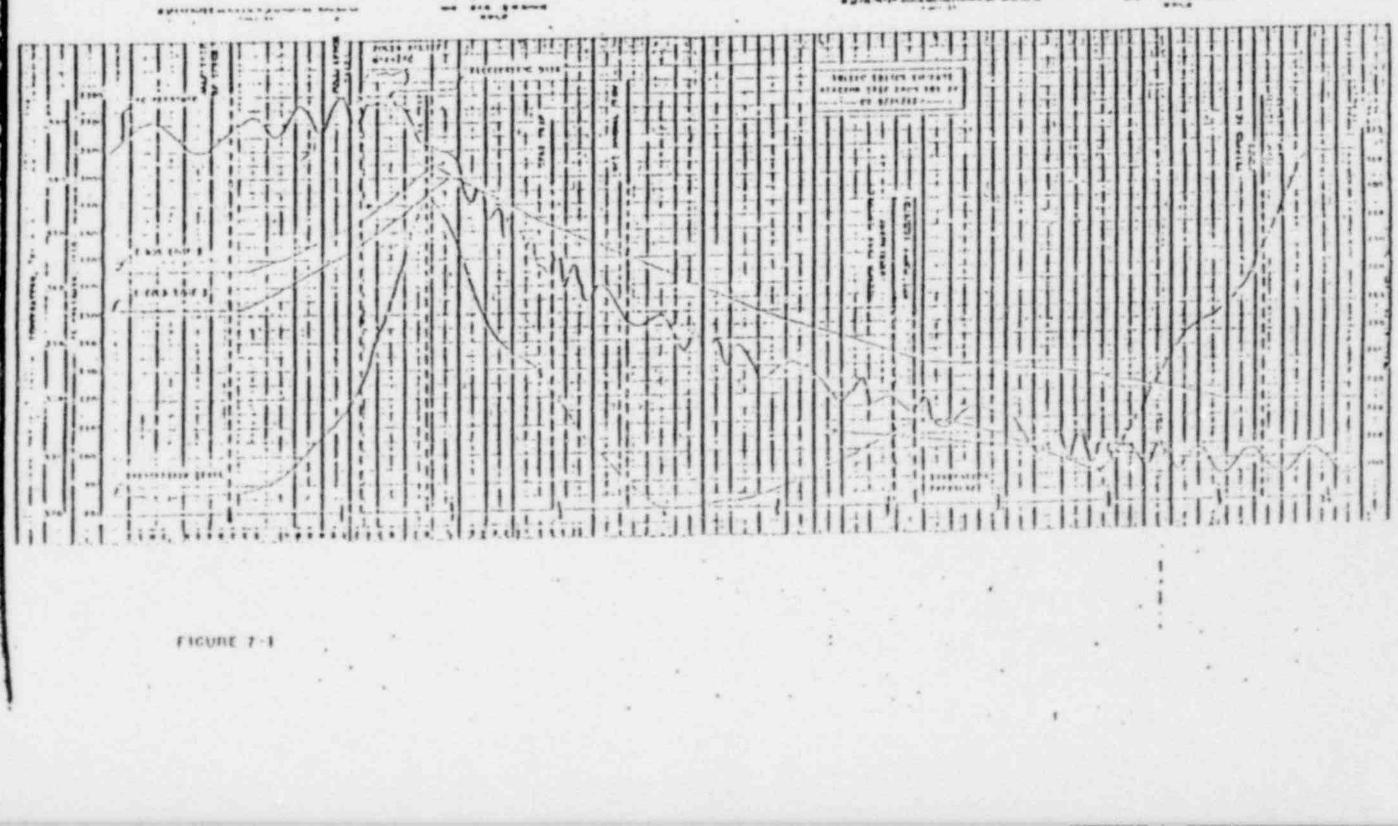


FIGURE 7-1

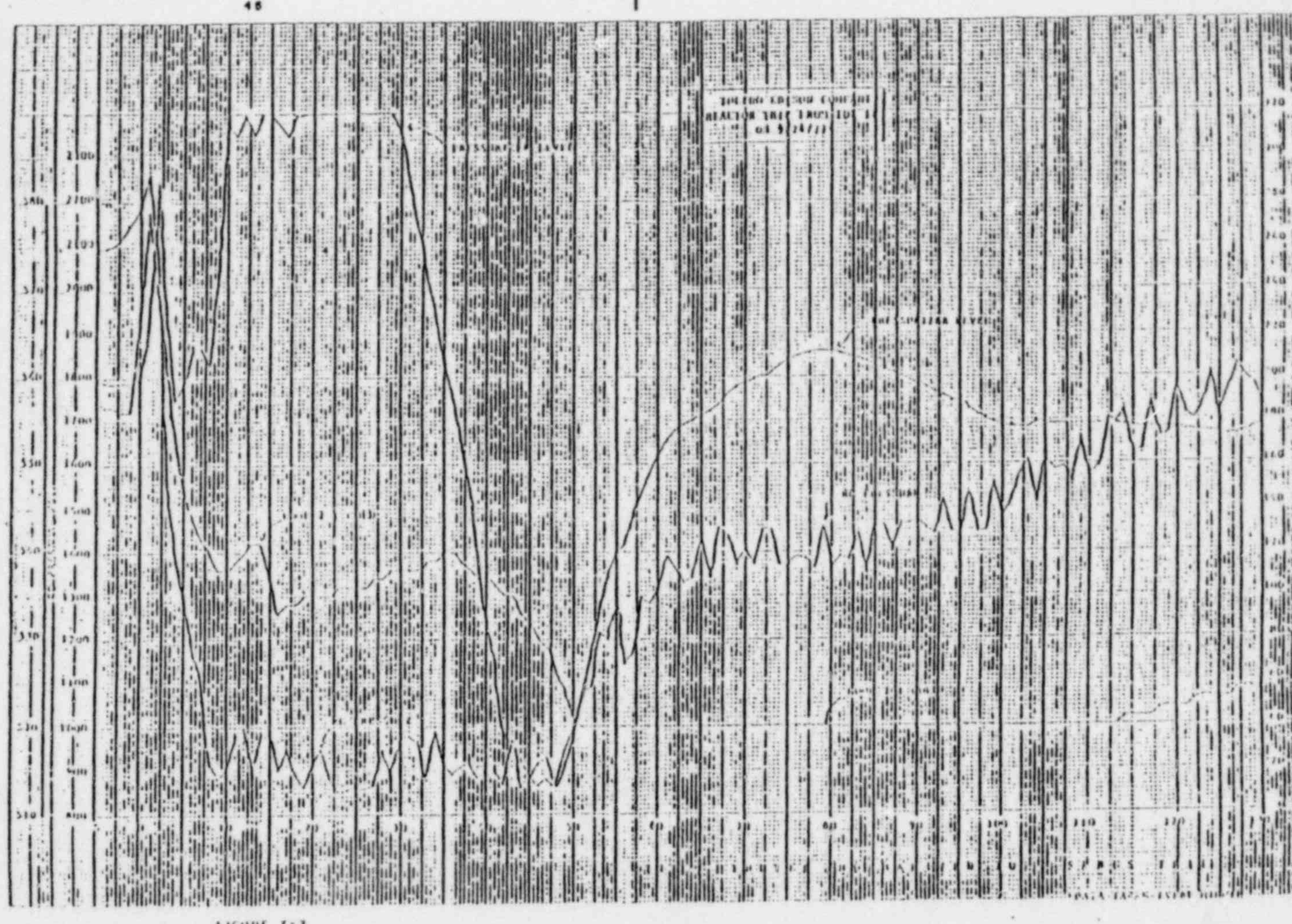
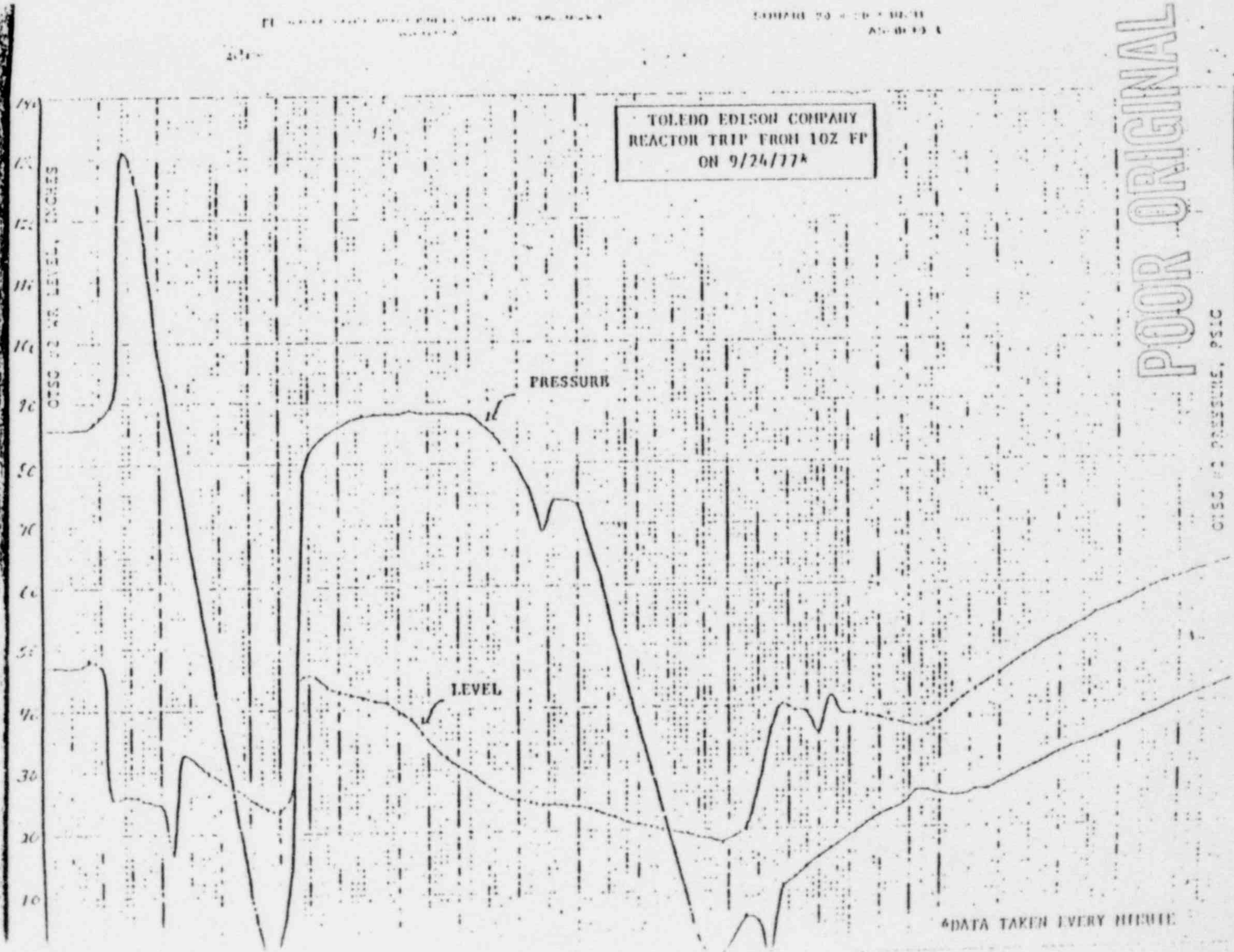
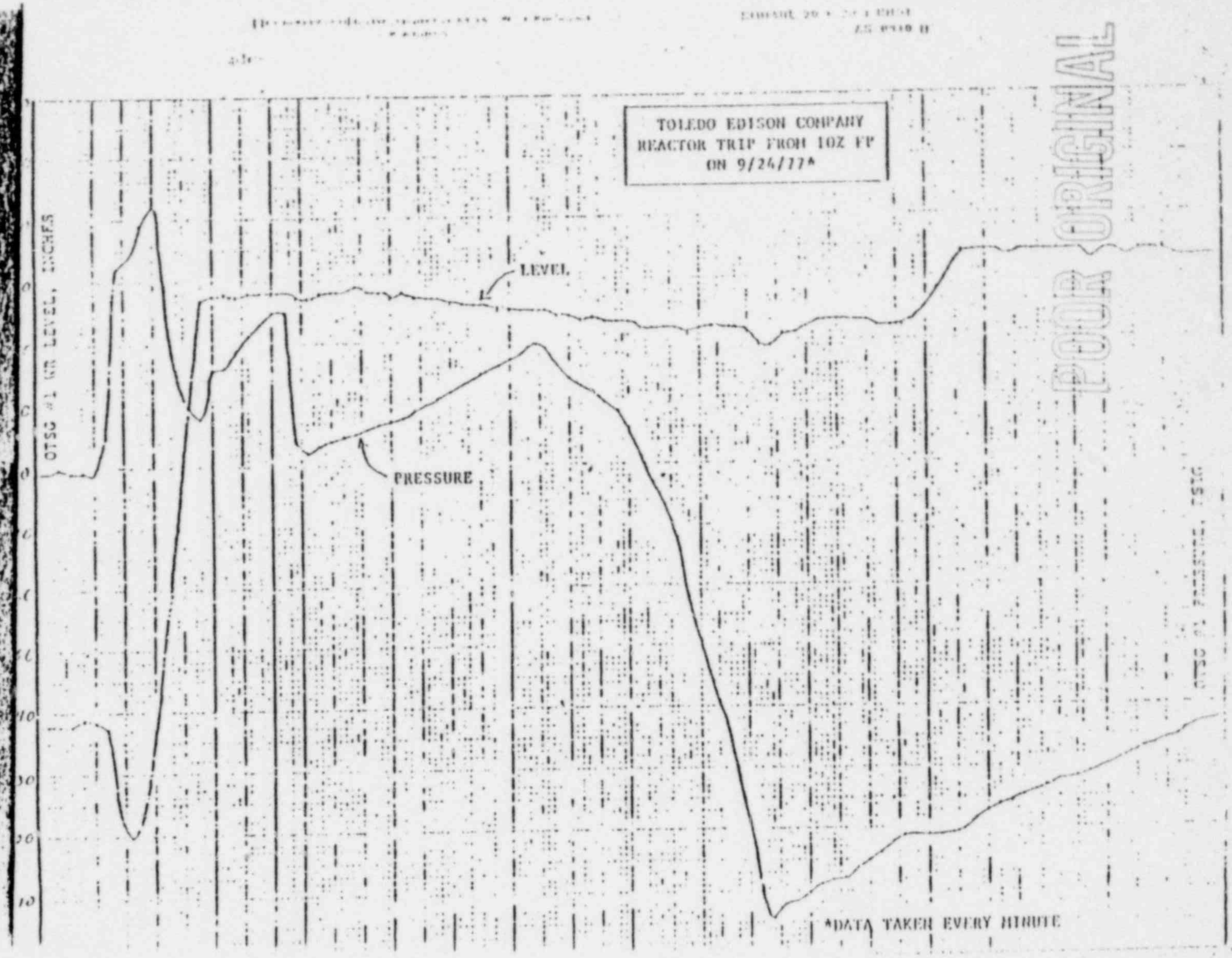


FIGURE 7-2

POOR ORIGINAL


TOLEDO EDISON COMPANY
REACTOR TRIP FROM 10% FP
ON 9/24/77*
OTSG #2 WR LEVEL, INCHES
PRESSURE
LEVEL
OTSG #2 PRESSURE, PSIG
*DATA TAKEN EVERY MINUTE
10
20
30
40
50
60
70
80
90
100
110
120
130
140


TOLEDO EDISON COMPANY
REACTOR TRIP FROM 10% FP
ON 9/24/77*
LEVEL
PRESSURE
OTSG #1 WR LEVEL, INCHES
*DATA TAKEN EVERY MINUTE
POOR ORIGINAL

C. System Description

Steam and Feedwater Rupture Control System

1. General

The steam and feedwater rupture control system (SFRCS) is an automatic system designed to protect against the following incidents:

a. Main steam line rupture, either upstream or downstream of main steam isolation valve (MSIV). This condition, if allowed to proceed, could rapidly blow down both steam generators, resulting in a rapid RCS cool down and therefore a rapid reactivity insertion under certain core conditions.

b. Main feedwater line rupture. If on the steam generator side of the feedwater check valve, this is approximately the same accident as the steam line rupture; on the feedwater side of the feedwater check valve this results in a total loss of feedwater.

c. Loss of all feedwater. This (as well as the above incidents) could result in boiling both steam generators dry. If this happens, there would be no steam available for running auxiliary feedwater pumps to remove decay heat.

d. Loss of 4 reactor coolant pumps (RCP). This results in loss of reactor coolant flow and therefore auxiliary feedwater is needed to establish reactor coolant natural circulation flow.

The SFRCS, upon indication of conditions a, b and c above will isolate both steam generators (close the main feedwater valves and main steam line valves and trip the turbine) and start the auxiliary feedwater system. Auxiliary feedwater is initiated to keep steam available for the auxiliary feed pump turbines and to remove decay heat from the reactor coolant system. Once this is accomplished, the operator will have time to begin a cool down in an orderly manner.

2. Design Criteria

The design criteria for the SFRCS and the auxiliary feedwater system are as follows:

a. The system must perform its safety function after a single active failure has occurred. This means that the single failure of any power supply, pump, turbine, instrument or control system logic channel will not prevent the system from removing decay heat from the reactor coolant system.

b. A main steam line break upstream of the MSIV or a main feedwater break downstream of the main feedwater isolation valve will disable one steam generator. After this event both auxiliary feed pumps and turbines will be aligned to the remaining intact steam generator. This remaining steam generator has adequate capacity to remove the decay heat from the reactor coolant system.

3. Functional Description (Refer to Enclosures 1 and 2)

The SFRCS is divided for redundancy, diversity, and testability into four logic channels. Logic channels 1 and 3 form channel 1, and logic channels 2 and 4 form channel 2. In one cabinet one logic channel has an AC power supply, the other a DC supply:

Logic Channel	Cabinet	Power Supply
1	C5762A	Y1 (120V AC)
2	C5792	Y2 (120V AC)
3	C5762A	D1P (125V DC)
4	C5792	D2P (125V DC)

Each logic channel receives the following inputs which will cause it to trip:

a. Six pressure switches, two on each main steam line set at 600 psig decreasing and one on each main steam line set at 650 psig decreasing.

b. Two main feedwater pressure differential switches, one from each main feedwater line (see Enclosure 1 for sensing points) set at 177 psid steam generator pressure higher than main feedwater line pressure.

c. Two level transmitters with bistables, one on each steam generator set at 17" decreasing level on the startup range.

d. A contact from RPS pump power sensing circuit; contact opens on loss of all four RCP's.

The SFRCS cabinets consist basically of an AC and a DC power supply, input buffers, logic modules, and output relays. The output relays de-energize to actuate their associated equipment. They also turn out a light on the cabinet when in the tripped state.

Each input to SFRCS has a test switch and light so that a trip of that input can be initiated for testing purposes.

The outputs from the SFRCS are contacts from the output relays. These contacts are in the control circuits for the SFRCS actuated equipment. Most components require two SFRCS logic channels to trip to actuate. See Enclosure 2 for a listing of actuated equipment.

There is a block feature associated with the low steam pressure trip. To prevent the system from actuating on cooldown, each logic channel has a "block" pushbutton on C5721 and on the SFRCS cabinet. When steam pressure goes below 650 psig a block permissive light is received on C5721 along with annunciator and computer alarms. When the block button is pushed, the channel will not trip on low steam pressure and a "MN STM LOW PRESS TRIP BLKD" light is actuated on C5721 as well as annunciator and computer alarms. On a heatup the block signal is automatically removed when the steam generator [illegible]

There is another block which is utilized on cooldown. If the decay heat system suction valves from the reactor coolant system (DH11 and 12) are open, this block will prevent the opening of the steam inlet valves to the auxiliary feed pump turbines. This prevents the SFRCS from starting the auxiliary feed pumps when all reactor coolant pumps are secured on shutdown. This "block" is automatically removed when the decay heat system is shut down on startup.

4. System Logic

a. The response of the actuated components depends on the type of trip: (refer to Inclosure 2)

1. On low steam pressure on one main steam line, both steam generators are isolated. In addition, both auxiliary feed pumps are aligned to the steam generator which is above 600 psig.

   If both steam generators go below 600 psig, both steam generators are isolated and no auxiliary feedwater is initiated.

   If any other trip (such as low steam generator level) accompanies a low steam pressure trip, the valves will align per low steam pressure trip logic.

2. On high feedwater pressure differential or low steam generator level on one steam generator, both steam generators are isolated and each auxiliary feedwater pump is aligned to feed its respective steam generator (1 to 1 and 2 to 2).

3. On loss of all four reactor coolant pumps, each auxiliary feedwater pump is aligned to its respective steam generator. The steam generators are not isolated.

4. On all of the above events, the turbine is tripped by the SFRCS.

b. The auxiliary feedwater pump governor control switch in the control room bus has 3 positions:

   Auto-Essential (SFRCS)
   ICS
   Manual

In the auto-essential position, the auxiliary feedwater pump is in auto-essential level control. In the ICS position, the auxiliary feedwater pump is on level control from the ICS; via the Hand-Auto station. In manual, the auxiliary feedwater pump is controlled by the operator with the Raise-Lower switch.

c. The SFRCS starting of the auxiliary feedwater pumps will automatically reset once the trip condition on the input is removed. None of the valves, however, will return to their original position until operated individually from the control room or a new trip condition occurs.

5. System Operation

In order to understand the operation of the SFRCS system, it is best to follow the various system actions under several accident conditions. The following cases will be considered:

a. Steam Line Rupture
b. Feedwater Line Ruptu e
c. Loss of Feedwater Pumps
d. Loss of Four Reactor Coolant Pumps

Enclosures 1 and 2 should be used as an aid to understanding the description. All discussions assume 100% FP operation at start. Some non-SFRCS actions are considered to aid in understanding the transient.

(1) Steam Line Rupture - Assume steam line 1 shears downstream of MSIV. Steam pressure will rapidly drop. When either steam generator reaches 600 psig, all four logic channels will trip, isolating both steam generators. (See Enclosure 2 for specific valves.) The MSIV takes five seconds to shut, the main feedwater isolation valve 15 seconds. Both steam lines will probably drop below 600 psig, therefore, auxiliary feedwater will not start until one steam generator recovers to above 600 psig. Auxiliary feedwater pumps will align as described in Section 3 above to feed the steam generator that first recovers to 600 psig, with both auxiliary feed pumps. The SFRCS will trip the turbine. The reactor will trip on low pressure.

When both steam generators are above 600 psig, the trip condition automatically clears and the atmospheric vent valves may be used for pressure control cooldown if required and provided no other trips are present.

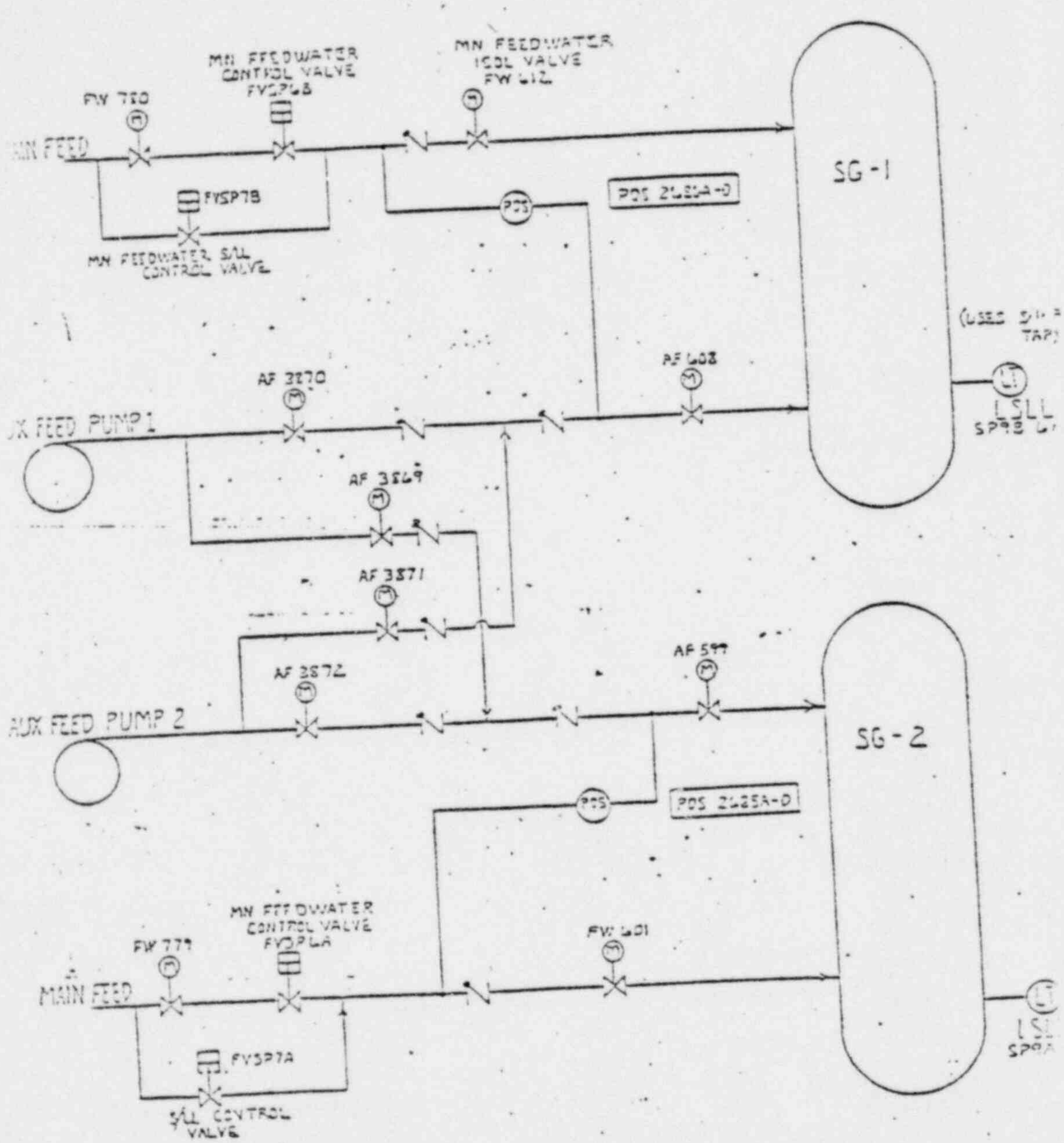
(2) Feedwater Rupture Line - Assume feedwater line 1 shears upstream of the feedwater line check valve. Feedwater pressure will rapidly drop. When either feedwater heater drops to 177 psig less than steam generator pressure, the SFRCS will isolate both steam generators and align the auxiliary feed pumps to their respective steam generator (1 to 1; 2 to 2). The reactor will trip on high pressure and the SFRCS will trip the turbine.

(3) Loss of Four Reactor Coolant Pumps - If all four reactor coolant pumps trip, the turbine will be tripped by the SFRCS and the reactor protection system will trip the reactor. The SFRCS will initiate auxiliary feedwater. The steam generators will not be isolated.

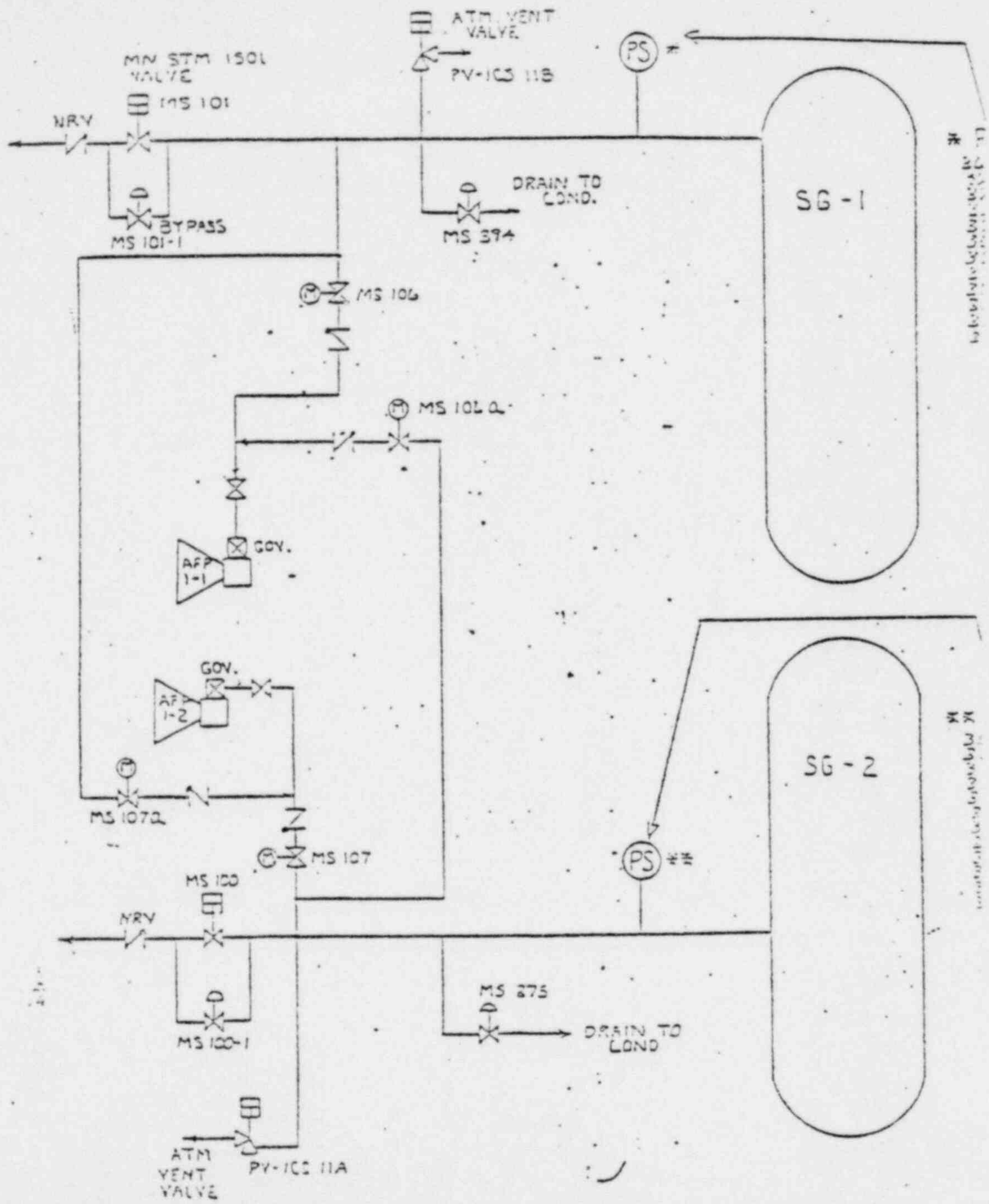
db 20-[illegible]

ENCLOSURE 1 SFRCS ACTUATED EQUIPMENT (FEEDWATER)

(FOR STEAM VALVES SEE NEXT PAGE)



ENCLOSURE 1 SFRCS ACTUATED EQUIPMENT (STEAM)



ENCLOSURE 2

STEAM-FEEDWATER RUPTURE CONTROL SYSTEM ACTUATION

CHANNEL 1 (C 5762A) / CHANNEL 2 (C 5792)	MS 101 / MS 101	MS 100 / MS 100	MS101-1 NOTE 3 / —	— / MS100-1 NOTE 3	MS 394 NOTE 3 / —	— / MS 375 NOTE 3	ICS 11B NOTE 3 / —	— / ICS 11A NOTE 3	FW 612 / —	— / FW 601	FW 780 / —	— / FW-775	SP 7B NOTE 3 / —	— / SP 7A NOTE 3
LOW PRESSURE MAIN Steam Line 1 (<600#)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW PRESSURE MAIN Steam Line 2 (<600#)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
STM. - EVAP SG 1 HIGH (>177 PSID)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
STM. - EVAP SG 2 HIGH (>177 PSID)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW LEVEL SG 1 (<17" SUR)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW LEVEL SG 2 (<17" SUR)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOSS OF 4 RC PUMPS														

CHANNEL 1 (C 5762A) / CHANNEL 2 (C 5792)	SP 6A / —	— / SP 6B	MS 106 / —	— / MS 107	MS 106A / —	— / MS107A	AF3870 / —	— / AF3872	AF 3869 / —	— / AF3871	AF 608 / —	— / AF 599	MAIN TURBINE
LOW PRESSURE MAIN STEAM LINE 1 (<600#)	SHUT	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN	TRIP
LOW PRESSURE MAIN STEAM LINE 2 (<600#)	SHUT	SHUT	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN	SHUT	TRIP
STM-EVAP SG 1 HIGH >177 PSID	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
STM-EVAP SG 2 HIGH >177 PSID	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOW LEVEL SG 1 (<17" SUR)	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOW LEVEL SG 2 (<17" SUR)	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOSS OF 4 RC PUMPS			OPEN NOTE 2	OPEN NOTE 2	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP

NOTES:
1. If both main steam lines are <600#, these valves shut.
2. These valves will not open if DH 11 and DH 12 (DH Suction from RCS) are open.
3. These valves are closed on a ½ channel trip.

File: 0017,0486, M-36

October 11, 1977

Serial No. 391

Docket No. 50-346

TOLEDO EDISON

LOWELL E. ROE
Vice President
Facilities Development
(419) 259-5242

Mr. James G. Keppler
Regional Director, Region III
Office of Inspection & Enforcement
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Dear Mr. Keppler:

This letter supersedes my letter to you on this subject dated October 5, 1977.

In accordance with 10 CFR Part 21.21(b), this is a report of a defect in a component installed in the Davis-Besse Nuclear Power Station Unit No. 1. The component involved is the governor on the auxiliary feed pumps.

The auxiliary feed pumps were supplied by Byron Jackson Pump Division. The steam driven pump turbine was supplied by Terry Corporation to Byron Jackson. In turn, the turbine governor was supplied to Terry Corporation by Woodward Governor Company. The turbine governor is identified as a type PG-PL, which has a servomotor control employing a Bodine Electric Company motor.

The defect involves a potential for the governor to bind under certain conditions and preventing the turbine from coming up to design speed. The operating procedures for this equipment called for the governor to be placed in the high speed stop position prior to shutting down the turbine. Investigation has shown that with the Bodine servomotor driving against the high speed stop, a misalignment force is applied to the T-bar of the governor linkage. This misalignment force creates a potential for the governor to bind at a speed position less than design speed upon a turbine startup. This misalignment force does not always cause the governor to bind and this misalignment force can be removed by driving the Bodine servomotor away from the high speed stop.

The safety hazard which could be created is the potential for both auxiliary feed pumps to fail to come up to design speed upon startup. This could result in a substantial loss of auxiliary feedwater flow to the steam generators when such flow was required. This in turn could cause significant reactor coolant system pressure/temperature transients, and significant boiling in the reactor coolant system if substantial decay heat were present in the reactor core.

The evaluation and identification of this defect was provided to me on September 30, 1977, and was discussed with Mr. T. Harpster of your office on September 30, 1977.

There are two identical auxiliary feed pumps with the turbine governors, described above, installed in the Davis-Besse Nuclear Power Station Unit No. 1.

The corrective action taken was to modify the governor including the removal of portions of the pneumatic speed-setting mechanism to assure that the governor will properly respond to speed demand signals. The pneumatic speed-setting mechanism was never an integral part of the functioning of the governor, because the governor employed servomotor control. This modification was accomplished at the Woodward Governor Company facilities. Subsequent testing at these facilities has proved the proper functioning of the governor. The modifications were completed prior to the current unit startup. The governors have been tested for proper functioning on auxiliary steam, and the surveillance test will be completed during Mode 3 of the current startup.

Yours very truly,

Lowell E. Roe

Lowell E. Roe
Vice President
Facilities Development

db b/9-10

bcc:
P. M. Smart, Esq.
G. Charnoff, Esq.
D. H. Hauser, Esq.
W. A. Johnson
J. S. Grant
E. C. Novak
C. R. Domeck
J. D. Lenardson
J. C. Evans
R. Rosenthal
P. T. Anas
A. H. Lazar

E. Historical Log of Station Operations (September 24 - October 28)

Sept. 24	Reactor critical at 15% power, generator on the line at 110-140 mw, performing controls tuning
	1700 - Discovered steam leak on steam lead between No. 2 Turbine Control Valve and high pressure turbine
	1830 - Turbine-generator taken off the line to repair steam leak. Reactor critical at about 9% power.
	2135 - Received Steam and Feedwater Rupture Control System Actuation, resulting in Reactor Trip, and Safety Features Actuation
	2345 - Plant stable at 1800 psig, T_{ave} = 525°F
Sept. 25	0415 - Started Plant Cooldown
	0645 - Completed initial survey of Containment
Sept. 26	Cleanup and repairs begun
Sept. 30	Completed repair and replacement of mirror insulation on No. 2 Steam Generator
Oct. 3	Auxiliary Fee[illegible] Governors removed and sent to Woodward Gov[illegible] Factory
	Quench Tank Rupture Disc replaced
Oct. 5	Vented Reactor Coolant System and run Reactor Coolant Pumps to get data to evaluate status of pumps and seals.
Oct. 6	Started Feedwater Cleanup in preparation for Reactor Coolant System heatup
Oct. 7	1830 - Received NRC approval to proceed with plant startup
Oct. 8	1530 - Checkout of Auxiliary Feedpumps (using Auxiliary Steam) completed
Oct. 11	Attempted to test pressurizer power relief valve. Unsuccessful due to electrical circuit problems.
Oct. 12	Pressurizer power relief valve control circuit working, stroked valve and it stuck open again

Oct. 13	Crosby man on site again working on Power Relief Valve. Increased RCS pressure to complete testing of Reactor Coolant Pumps.
Oct. 15	Completed repairs to Power Relief Valve and tested it successfully
Oct. 16	Completed testing of Auxiliary Feedpumps. Governors had been modified by Woodward to prevent sticking
	1306 - Reactor critical
	2316 - Rolled the turbine
Oct. 17	0307 - Generator synchronized
	1135 - Generator off the line for overspeed tests
	1805 - Commenced Reactor Shutdown for Unit Power Shutdown Test. We are now back in Power Escalation Sequence
Oct. 18	0200 - Completed Unit Power Shutdown Test
	0300 - Commenced Reactor Startup
	1036 - Generator Synchronized
Oct. 19	1124 - Generator off line to repair steam leak between No. 1 Control Valve and HP Turbine
Oct. 20	2241 - Generator synchronized
Oct. 23	1009 - A half trip of SFRCS caused low steam generator level, resulting in full SFRCS trip, Reactor trip and SFAS
Oct. 27	2330 - Reactor Critical
Oct. 28	1151 - Generator Synchronized

ENCLOSURE 9

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

DEC 6 197

Those on Attached List

MONTHLY LICENSEE EVENT REPORT (LER) PWR LISTINGS

The enclosed LER computer listings provide information on certain licensee event reports entered into the file during the month of November. The two listings provided are as follows:

1. LER output on PWR events sorted by cause, facility, and event date.

2. LER output on events involving personnel error sorted by facility and event date.

If you desire additional information or special searches, please do not hesitate to contact us.

J. A. Kirk, Acting Director
Regulatory Info. Systems Division
Office of Management Information
and Program Control

Enclosure:
As stated

PROCESSED DURING NOVEMBER FOR POWER REAC[illegible]
OUTPUT SORTED BY CAUSE, FACILITY, AND EVENT DATE

CAUSE CODE/CAUSE SUBCODE/ FACILITY/COMP./COMP. SUBCODE/ SYSTEM/DISCOVERY/MANUFACTURER	DOCKET NO./ LER NO./ CONTROL NO.	EVENT DATE/ REPORT DATE/ REPORT TYPE	STATUS/ EVENT DESCRIPTION/ CAUSE DESCRIPTION	% POWER/
OTHER	05000302	092877	STEADY STATE OPERATION	9?2
CAUSE SUBCODE NOT PROVIDED	77 031	101977	(77-128) IN MODE 1 RUNNING MONTHLY EMERGENCY DIESEL TES[illegible] [illegible]	
CRYSTAL RIVER-3	019302	30 DAY	ER. DIESEL GEN. FAILED TO START CONTRARY TO TECH SPEC. REDUNDANT DIESEL	
ENGINES, INTERNAL COMBUSTION			3A AVAILABLE & OPERABLE. FIRST TIME OCCURRENCE. CABLE INSP. [illegible]	
SUBCOMPONENT NOT APPLICABLE			BREAKER VERIFICATION SP-321 PERFORMED. 3B EMER. DIESEL GEN.RESTORED O	
EMERG GENERATOR SYS + CONTROLS			PERABLE IN 7 HOURS.	
ROUTINE TEST/INSPECTION				
FAIRBANKS MORSE				
			LOSS OF DIESEL START PERMISSIVE DUE TO LOW LUBE OIL PRESSURE. EVENT COU LD NOT BE MADE TO REPEAT & HAS NOT REPEATED TO THIS DATE.	
OTHER	05000302	101177	STEADY STATE OPERATION	10?
CAUSE SUBCODE NOT PROVIDED	77 031	110377	(77-132) 11 & 26 OCTOBER 1977, UNITS 1 & 2 BATTERIES DIDN'T M[illegible] ACCEPT	
CRYSTAL RIVER-3	019300	30-DAY	ANCE CRITERIA OF QUARTERLY & WEEKLY SURVEILLANCE PROCEDURES, [illegible]	
BATTERIES + CHARGERS			N A CONDITION CONTRARY TO T.S. 3.8.1.1.A. REDUNDANCY HAS MAINTAINED WIT	
SUBCOMPONENT NOT APPLICABLE			H EMER. GEN. THIRD & FOURTH OCCURRENCES OF EVENT. BATTERIES RESTORED O	
DC ONSITE POWER SYS + CONTROLS			PERABLE WITHIN 24 HOURS EACH TIME.	
ROUTINE TEST/INSPECTION				
EXIDE INDUSTRIAL DIV				
			STRATIFICATION OF ELECTROLYTE DUE TO BATTERIES BEING IN NO LOAD CONDITIO N. RECOMMENDATION TO INCREASE FLOAT VOLTAGE .05 VOLTS WILL BE SUBMITTED TO PRECLUDE RECURRENCE.	
OTHER	05000346	092477	ROUTINE SHUTDOWN OPERATIONS	60?
NOT APPLICABLE	77-016/011-0	100777	HALF TRIP OF STEAM & FEEDWATER RUPTURE CONTROL SYSTEM CAUSED RISE IN RE	
DAVIS-BESSE-1	019300	2-WEEK	CTOR COOLANT SYSTEM TEMP & PRESSURE. CAUSED PRESSURIZER POWER RELI[illegible] VA	
INSTRUMENTATION + CONTROLS			LVE TO OPEN & VALVE FAILED TO CLOSE, CAUSING REDUCTION IN RCS PRESSURE.	
OTHER			LCOS WERE EXCEEDED FOR 5 T.S., 3.4.1, 3.4.5, 3.4.6.2, 3.6.1.4 & 3.7.1.2	
OTHR INST SYS REQD FOR SAFETY			.	
OPERATIONAL EVENT				
CONSOLIDATED CONTROLS CORP.				
			HALF TRIP CONDITION FROM SFRCS CHANNEL 2, WHICH CAUSED VALVE [illegible] LOSE. CAUSE OF THIS HALF TRIP HAS NOT BEEN POSITIVELY DETERMINED ALTHOU GH EXTENSIVE INVESTIGATION HAS REVEALED LOOSE CONNECTIONS AT TERMINAL BO ARDS (POSSIBLE CAUSE).	

ENCLOSURE 10

NUREG 0020
VOL. 1 NO. 3
NOVEMBER

OPERATING UNITS STATUS REPORT

DATA AS OF 10-31-77

LICENSED OPERATING REACT

DATA FOR DECISIONS

- Department Of Energy
- Nuclear Regulatory Commission

DAVIS-BESSE 1

NRC POWER RESTRICTIONS: NONE

FACILITY DATA

Facility Description

1. Location: State/County Distance from nearest population center	Ohio/Ottawa Northeast, 12 miles
2. Electric Reliability Council	CAPCO
3. Type of Reactor	PWR (B&W)
4. Licensed Power Level (MWt)	2772
5. Design Electrical Rating (MWe Net)	906
6. Date of Initial Criticality	N/A
7. Date of Commercial Operation	N/A
8. Condenser Cooling Method	Cooling Tower
9. Condenser Cooling Water Source	Lake Erie

Utility & Contractor Information

10. Licensee	Toledo Edison Co.
11. Corporate Address	Edison Plaza, 300 Madison Ave. Toledo, Ohio 43652
12. Corporate Contact	Lowell Roe, V.P., Power (419) 259-5000
13. Architect/Engineer	Bechtel Corp.
14. Nuclear Steam Supply System	Babcock & Wilcox Co.
15. Constructor	Bechtel Corp. (Mngr.)

Regulatory Information

16. IE Region Responsible	III
17. IE Branch Chief	G. Fiorelli
18. IE Senior Inspector	R. C. Knop
19. IE Principal Inspector	T. N. Tambling
20. Licensing Project Manager	L. Engle
21. Docket Number	50-346
22. License Number/Date of Issue	NPF-3 (04-22-77)

INSPECTION STATUS

ENFORCEMENT STATUS

NONE

INSPECTION STATUS

2. OTHER SIGNIFICANT ITEMS

A. SYSTEMS AND COMPONENT PROBLEMS:

None.

B. FACILITY ITEMS (PLANS AND PROCEDURES):

None.

C. MANAGERIAL ITEMS:

None.

LAST IE SITE INSPECTION DATE: September 21-22, 1977

INSPECTION REPORT NO: 77-29

3. SUMMARY

INSPECTION SUMMARY

Inspection on September 21-22, (77-29): Review vibration and loose parts monitoring noise analysis data; examine the implementation of the licensee LPM data acquisition program. The inspection involved 13 inspector-hours onsite by one NRC inspector. No items of noncompliance or deviations were found in the areas inspected.

PLANT STATUS

Plant outage from the September 24, 1977, RCS depressurization event continued until October 16, 1977. On October 22, 1977, the reactor tripped on loss of feedwater to the steam generators due to a spurious steam Feedwater Rupture Control half trip (same type half trip that lead to September 24, 1977, event). All plant equipment functioned as required to the transient. Outage continued to October 27, 1977.

REPORTS RECEIVED FROM LICENSEE

NUMBER	DATE OF EVENT	DATE OF REPORT	TYPE OF REPORT	SUBJECT
NP-32-77-36	09/24/77	10/07/77	14 Day Report	Loss of RCS pressure due to failure of pressurizer power operated relief valve.
NP-33-77-56	08/16/77	09/15/77	30 Day Report	Diesel Generator No. 1 inoperable.
NP-33-77-57	08/14/77	09/13/77	30 Day Report	DH pump 1-2 inoperable due to injection valve closed.
NP-33-77-53	08/24/77	09/22/77	30 Day Report	RE-1 inoperable for connection to the [illegible].
NP-33-77-61	08/23/77	09/19/77	30 Day Report	AF Pump 1-2 inoperable due to a planned adjustment.
NP-33-77-62	08/25/77	09/27/77	30 Day Report	AF Pump 1-1 inoperable due to replace the relief valve in cooling water line.
NP-33-77-64	08/23/77	09/22/77	30 Day Report	RC pump motor 1-1-2 declared inoperable due [illegible] capacitor.
NP-33-77-66	08/26/77	09/19/77	30 Day Report	DH pump 1-2 inoperable to install union in cooling water line.
NP-33-77-69	08/23/77	09/13/77	30 Day Report	Hydraulic snubber [illegible] inoperable.
NP-33-77-72	09/21/77	09/26/77	30 Day Report	SG 1-2 level exceed the [illegible] level.
NP-33-77-74	09/03/77	10/04/77	30 Day Report	RCS flow less than 2900 gallons per minute.
NP-33-77-75	08/29/77	09/28/77	15 Day Report	RCS Tave less than 525 degrees F.
NP-33-77-76	09/01/77	10/04/77	30 Day Report	Single RCS pump operating in a single loop.

Reviewed by MIPC OED: M.R. Beebe DATE: 11/29/77

Reviewed by NRR DOR: L. Engle DATE: 12/1/77

ENCLOSURE 11

NUREG 0020
VOL. 1 NO. 4
DECEMBE

OPERATING UNITS STATUS REPORT

DATA AS OF 11-30-77

LICENSED OPERATING REACT

DATA FOR DECISIONS

- Department Of Energy
- Nuclear Regulatory Commission

DAVIS-BESSE 1

NRC POWER RESTRICTIONS: None

FACILITY DATA

Facility Description

1	Location (State/County) (nearest population center)	Ohio/Ottawa; Northeast 17 miles
2	Electric Reliability Council	CAPCO
3	Type of Reactor	PWR (B&W)
4	Licensed Power Level (MWT)	2772
5	Design Electrical Rating (MWE Net)	906
6	Date of Initial Criticality	N/A
7	Date of Commercial Operation	11/20/77
8	Condenser Cooling Method	Cooling Tower
9	Condenser Cooling Water Source	Lake Erie

Utility & Contractor Information

10	Licensee	Toledo Edison Co.
11	Corporate Address	Edison Plaza, 300 Madison Ave., Toledo, Ohio 43652
12	Corporate Contact	Lowell Roe, V.P., Power (419) 259-5000
13	Architect/Engineer	Bechtel Corp.
14	Nuclear Steam Supply System	Babcock & Wilcox Co.
15	Constructor	Bechtel Corp. (Mng)

Regulatory Information

16	IE Region responsible	III
17	IE Branch Chief	G. Fiorelli
18	IE Senior Inspector	R. C. Knop
19	IE Principal Inspector	T. N. Tambling
20	Licensing Project Manager	L. Engle
21	Docket Number	50-346
22	License Number/Date of Issue	NPF-3 /04-22-77

INSPECTION STATUS

ENFORCEMENT STATUS

CONTRARY TO THE APPROVED QUALITY ASSURANCE MANUAL AND CRITERION V OF 10 CFR 50, APPENDIX B, ADMINISTRATIVE PROCEDURE 1023.00 WAS NOT COMPLETELY ADHERED TO IN THE LOGGING AND REVIEW OF JUMPER-LIFT WIRES. (7732 DEFICIENCY)

2. OTHER SIGNIFICANT ITEMS

A- SYSTEMS AND COMPONENT PROBLEMS:

* As a result of a spurious trip on September 24, 1977, in the Steam Feedwater Rupture Control System, feedwater was lost to No. 2 steam generator. This resulted in a sudden depressurization transient in both the secondary and primary water systems. These operational transients were aggravated by the failure of the No. 2 auxiliary feedwater pump to come up to operating speed and the pressurizer power operated relief valve failing open. Design modifications were made to the governor on the auxiliary feedwater pump turbine and the power operated relief valve to prevent reoccurrence. (77-32)

B- FACILITY ITEMS (PLANS AND PROCEDURES):

* Power ascension testing is to be continued at the 40% power level. (77-32)

C- MANAGERIAL ITEMS:

None.

*LAST IE SITE INSPECTION DATE: September 26-30; October 5-7, 11-14, 18-21 and 25-28, 1977

* INSPECTION REPORT NO: 77-28, 77-30, 77-31 and 77-32

3. SUMMARY

INSPECTION SUMMARY

* Inspection on October 11-14, (77-28): Unannounced inspection regarding implementation of approved security plan which was submitted in accordance with 10 CFR 50.34(c); applicable parts of 10 CFR 73.55 requirements effective as of May 25, 1977; and 10 CFR 73.70 requirements. Specifically, the inspection covered areas relative to the security organization, physical barriers, access controls, detection aids, communication controls, testing and maintenance of security equipment, response controls and records requirements. The inspection involved 64 inspector hours onsite by two NRC inspectors. Additionally, an enforcement meeting was held with corporate and site management on November 4, 1977, to discuss the inspection findings. This meeting involved 6 hours onsite by the Safeguards Branch Chief, the Chief of Security and Investigations Section, and the principal physical security specialist for this inspection. Of the eight areas inspected, no apparent items of noncompliance were identified in four areas; six items of noncompliance were identified in four areas (Physical Barriers, Access Controls, Detection Aids and Records). The Enforcement Conference held on November 4, 1977, with representatives of the licensee's management developed that corrective action has been initiated with respect to all of the items noted above. The adequacy of the action will be reviewed on receipt of the licensee's response to the Notice of Violation.

* Inspection on October 25-28, (77-30): Nuclear Material control and accountability including facility organization and operation; measurements

REPORTS RECEIVED FROM LICENSEE

NUMBER	DATE OF EVENT	DATE OF REPORT	TYPE OF REPORT	SUBJECT	PUBLIC ANNOUNCEMENT
NP-32-77-17	10/21/77	11/03/77	14 Day Report	Cooling water to AFP bearings improperly aligned.	No
NP-32-77-18	10/31/77	11/17/77	14 Day Report	Inoperable AFP 1-2 due to turbine governor valve drifting closed.	No
NP-32-77-19	11/17/77	11/29/77	14 Day Report	Isolation of SFRCS on steam generator to feedwater differential pressure switches.	No
NP-33-77-73	10/16/77	11/03/77	30 Day Report	Decay heat valve pit opened to perform wiring change.	No
NP-33-77-76	10/10/77	11/01/77	30 Day Report	RPS channel accidentally de-energized.	No
NP-33-77-79	10/11/77	11/08/77	30 Day Report	Source range neutron detector NI-1 failed.	No
NP-33-77-80	10/10/77	11/11/77	30 Day Report	Governor valve closed on AFP 1-2.	No
NP-33-77-81	10/16/77	11/14/77	30 Day Report	Exceeded allowed containment to annulus delta P on startup.	No
NP-33-77-82	10/10/77	11/14/77	30 Day Report	EVS Train 2 damper failed to modulate correctly.	No
NP-33-77-83	10/25/77	11/22/77	30 Day Report	Failure of Valve AF 3872, AFP 1-2 to steam generator.	No
NP-33-77-84	10/25/77	11/23/77	30 Day Report	Surveillance test 5080.03, independent offsite AC source lineup, performed late.	No
NP-33-77-86	10/28/77	11/23/77	30 Day Report	Failure of RIS 2004 in SRM channel 4 to respond to check source.	No
NP-33-77-87	10/24/77	11/23/77	30 Day Report	SFAS channel 2 containment radiation [illegible].	No
NP-33-77-88	10/27/77	11/23/77	30 Day Report	Source range neutron detector NI-1 failed.	No
NP-33-77-92	11/01/77	11/29/77	30 Day Report	Failure to perform surveillance requirement of venting HPI valve HP 72.	No

Reviewed by MIPC OED: PESide **DATE:** [illegible]

Reviewed by NRR DOR: [illegible] **DATE:** 1/4/78

SEE CONTINUATION PAGE 2-28A

ENCLOSURE 12

CURRENT EVENTS

UNITED STATES
NUCLEAR
REGULATORY
COMMISSION

POWER REACTORS

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 SEPTEMBER - 31 OCTOBER 1977

(PUBLISHED DECEMBER 1977)

Porter EXHIBIT 2
FOR IDENTIFICATION
7/24/79 S. McCRYSTAL

OPERATOR ERROR

On January 11, 1977 while the Fort Calhoun Station Unit 1 was operating, water from the Refueling Water Storage Tank was pumped into the containment through the containment spray header due to an operator error.

During the performance of a quarterly test of the safety injection and containment spray pumps, the operator noticed an increase in the containment sump level approximately ten minutes after the low pressure safety injection pump had been started. Approximately 3300 gallons of water had been pumped to the containment. About one minute later the ventilation isolation actuation signal was received. At this time the operator realized he had failed to follow the surveillance procedures and had left the discharge valve of the low head safety injection pump open. He immediately secured the pump.

The Reactor Coolant System was checked for leakage and containment entry was made approximately one hour later. Inspection revealed that a discharge from the containment spray nozzles had occurred. A few minutes later power reduction was started. A second containment entry was made about an hour later, after containment air samples confirmed that a full face mask would provide adequate respiratory protection for the levels of radioactivity in the building. A detailed inspection revealed no serious deficiencies and no electrical grounds; the power reduction was terminated at a power level of 83%.

Although the operator had not followed the procedure and the discharge valve was open, the containment spray header isolation valve (HCV-345) and the low pressure safety injection to containment spray header cross-connect valve (HCV-335) should have prevented the event. The electric/pneumatic converter on HCV-345 had failed and both red and green position indication lights were on, indicating the valve was partially open. Prior to the event the auxiliary Building Equipment Operator had taken local control of the valve in an attempt to completely close the valve. After about 1/2 inch of stem travel, the operator removed the valve pin and the valve went back to its previous position as demanded by the valve positioner. The third valve (HCV-335) in the incident had a leakage problem that had been previously identified but no corrective action had been taken.

The pneumatic relay on valve HCV-345 was replaced and valve HCV-335 repaired. Valve HCV-344 and HCV-345 are now required to be placed in the test mode prior to operating the low pressure safety injection pump or contain spray pump for testing. This mode along with verification of an annunciator will ensure that both of these valves are in the fully closed position prior to pump operation.

VALVE MALFUNCTIONS

1. Primary System Depressurization

On September 24, 1977, Davis Besse Nuclear Power Station Unit No. 1 experienced a depressurization when a pressurizer power relief valve failed in the open position. The Reactor Coolant System (RCS) pressure was reduced from 2255 psig to 875 psig in approximately twenty-one (21) minutes. At the beginning of this event, steam was being bypassed to the condenser and the reactor thermal power was at 263 MW, or 9.5%. Electricity was not being generated. The following systems malfunctioned during the transient:

a. Steam and Feedwater Rupture Control System (SFRCS).

b. Pressurizer Pilot Actuated Relief Valve.

c. No. 2 Steam Generator Auxiliary Feed Pump Turbine Governor.

The event was initiated at 2134 hours, when a spurious "half-trip" occurred in the SFRCS, resulting in closure of the No. 2 Feedwater Startup Valve and loss of flow to No. 2 Steam Generator. Approximately one minute later, low level in the No. 2 Steam Generator caused a full SFRCS trip, closing the Main Steam Isolation Valves

(MSIV). The loss of heat sink for the reactor caused the RCS temperature, pressure, and pressurizer level to rise.

The RCS pressure increased to the pilot actuated relief valve setpoint (2255 psig) and the valve cycled open and closed nine times in rapid succession, failing to close on the tenth opening. Meanwhile, the reactor operator observed the pressurizer level increase and manually tripped the reactor about one minute after MSIV closure (two minutes into the transient). At this point the RCS pressure was approximately 2000 psig and decreasing while the pressurizer level had reached its maximum initial rise of about 310 inches. The RCS pressure continued to decrease due to the open relief valve and upon reaching 1620 psig approximately three minutes into the transient, actuated Safety Features including high pressure (water) injection and containment isolation.

Approximately five minutes into the transient the rupture disc on the pressurizer quench tank, which was receiving the RCS blowdown, burst. Bursting of the rupture disc was aggravated by the actuation of containment isolation, which had isolated the quench tank cooling system, resulting in expedited pressurization of the quench tank.

The RCS continued to blow down through the open pressurizer power relief valve and the quench tank rupture disc opening until primary coolant saturation pressure was reached, about six minutes into the transient. The formation of steam in the RCS caused an insurge of water into the pressurizer. This insurge and the high pressure water injection then restored pressurizer level to about 310 inches after nine minutes into the transient.

Approximately thirteen minutes into the transient, the secondary side of the No. 2 Steam Generator went dry. About fourteen minutes into the transient, the operators noticed the low level condition and found that the auxiliary feed pump was operating at reduced speed. Manual control of the auxiliary feed pump was started and water level restored to the No. 2 Steam Generator.

At approximately 21 minutes into the transient, the operators discovered that the pressurizer power relief valve was stuck open. Blowdown via this valve was stopped by closing the block valve, thus terminating the reactor vessel depressurization. The RCS pressure recovered to normal and cooldown of the system followed.

The reason for the spurious "half-trip" of the SFRCS has not yet been determined. An extensive investigation revealed several loose connections at terminal boards, but nothing conclusive.

Investigation into the failure of the pressurizer pilot actuated relief valve revealed that a "close" relay was missing from the control circuit. This missing relay would normally provide a "seal-in" circuit which would hold the valve open until the pressure dropped to 2205 psig. Without the relay the power relief valve cycled open and closed each time the pressure of the RCS went above or below 2255 psig. The rapid cycling of the valve caused a failure of the pilot valve stem, and this failure caused the power relief valve to remain open.

It was determined that the auxiliary feed pump did not go to full speed because of "binding" in the turbine governor.

The transient was analyzed by the NSSS vendor and determined to be within the design parameters analyzed for a rapid depressurization.

With exception of the above noted malfunctions, the plant functioned as designed and there was no threat to the health and safety of the general public.[2-3]

2. Feedwater Isolation Valves

On two occasions in July, at the Trojan nuclear plant, a hydraulic feedwater isolation valve failed to close upon receipt of a close signal. All other equipment required to operate, functioned normally.

The first failure, July 6, 1977, had been attributed to an improperly assembled solenoid in the hydraulic actuator. Investigation of the second failure indicated that both events were due to a lack of sufficient hydraulic pressure.

Failure of the valve to close was caused by the pressure regulator leaking and failing to close down to regulate the pressure. This caused the hydraulic system on the valve to be drained down to a point that the valve would not operate. Inspection of the regulator revealed that a locking screw on the regulator adjusting knob was loose and would allow the knob to vibrate to any position. With the regulator improperly set it would not close down to regulate pressure and would allow the hydraulic fluid to drain before the hydraulic operator could function. A similar problem was discovered on two other valves, although the maladjustment was not sufficient to prevent these valves from operating.

ENCLOSURE 13

ATOMIC ENERGY CLEARING HOUSE
(REG. U. S. PAT. OFF.)
PUBLISHED BY
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Vol. 24 January 9, 1978 No. 2

IN THIS WEEK'S ISSUE

NRC WILL HOLD PUBLIC HEARING ON PROPOSED CLEARANCE PROGRAM FOR SOME EMPLOYEES IN COMMERCIAL NUCLEAR INDUSTRY. Proposed changes to NRC regulations upgrading its safeguards program would apply to personnel who have access to or control over certain quantities of special nuclear material (high enriched uranium, plutonium and uranium-233), or access to protected areas of facilities such as nuclear power plants and fuel reprocessing plants.

The date and location of the hearing will be announced later.

The Commission will specifically seek comments of individuals and groups on such matters as:

(1) The advantages and disadvantages of alternative programs, such as psychological testing administered by licensees under standards established by the Commission, and alternative safeguards measures not involving investigation or testing of licensee employees.

(2) The extent to which the clearance program meets the performance requirements for protecting nuclear power reactors, particularly toward meeting the postulated threat of internal conspiracy.

(3) The desirability of applying the rule to university research and training reactors subject to Part 73 (physical protection of plants and materials) of NRC regulations.

(4) Impact of the proposed clearance program on transportation of special nuclear material.

Persons who wish to present oral or written statements on the proposed clearance program, announced by the NRC last March, must submit their name and name of their organization, if any, to the Secretary of the Commission, Washington, D.C. 20555, by January 27.

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to stocks, although restrictions on the enrichment of foreign uranium for domestic use were partially lifted. All restrictions were to be lifted by 1983.

During the same 9-month period, 123 tons of uranium compounds, including metals and alloys, valued at $2.9 million and 882 tons of uranium concentrate valued at $59.0 million were exported. The value of exported special nuclear materials, principally enriched uranium, for the first 10 months was $391 million.

\- 6 - 6 - 6 - 6 - 6 - 6 -

NRC'S REPORT OF CURRENT EVENTS FOR POWER REACTORS FOR THE PERIOD SEPTEMBER 1-OCTOBER 31, 1977, published December 1977, is presented below:

OPERATOR ERROR

On January 11, 1977 while the Fort Calhoun Station Unit 1 was operating, water from the Refueling Water Storage Tank was pumped into the containment through the containment spray header due to an operator error.

During the performance of a quarterly test of the safety injection and containment spray pumps, the operator noticed an increase in the containment sump level approximately ten minutes after the low pressure safety injection pump had been started. Approximately 3300 gallons of water had been pumped to the containment. About one minute later the ventilation isolation actuation signal was received. At this time the operator realized he had failed to follow the surveillance procedures and had left the discharge valve of the low head safety injection pump open. He immediately secured the pump.

The Reactor Coolant System was checked for leakage and containment entry was made approximately one hour later. Inspection revealed that a discharge from the containment spray nozzles had occurred . A few minutes later power reduction was started. A second containment entry was made about an hour later, after containment air samples confirmed that a full face mask would provide adequate respiratory protection for the levels of radioactivity in the building. A detailed inspection revealed no serious deficiencies and no electrical grounds; the power reduction was terminated at a power level of 83%.

Although the operator had not followed the procedure and the discharge valve was open, the containment spray header isolation valve (HCV-345) and the low pressure safety injection to containment spray header cross-connect valve (HCV-335) should have prevented the event. The electric/pneumatic converter on HCV-345 had failed and both red and green position indication lights were on, indicating the valve was partially open. Prior to the event the auxiliary Building Equipment Operator had taken local control of the valve in an attempt to completely close the valve. After about 1/2 inch of stem travel, the operator removed the valve pin and the valve went back to its previous position as demanded by the valve positioner. The third valve (HCV-335) in the incident had a leakage problem that had been previously identified but no corrective action had been taken.

The pneumatic relay on valve HCV-345 was replaced and valve HCV-335 repaired. Valve HCV-344 and HCV-345 are now required to be placed in the test mode prior to operating the low pressure safety injection pump or contain spray pump for testing. This mode along with verification of an annunciator will ensure that both of these valves are in the fully closed position prior to pump operation.

VALVE MALFUNCTIONS

1. Primary System Depressurization

On September 24, 1977, Davis Besse Nuclear Power Station Unit No. 1 experienced a depressurization when a pressurizer power relief valve failed in the open position. The Reactor Coolant System (RCS) pressure was reduced from 2255 psig to 875 psig in approximately twenty-one (21) minutes. At the beginning of this event, steam was being bypassed to the condenser and the reactor thermal power was at 263 MW, or 9.5%. Electricity was not being generated. The following systems malfunctioned during the transient:

a. Steam and Feedwater Rupture Control System (SFRCS)

b. Pressurizer Pilot Actuated Relief Valve.

c. No. 2 Steam Generator Auxiliary Feed Pump Turbine Governor.

[illegible]

[illegible] at [illegible] hours, [illegible] a spurious "half-trip" [illegible] SFRCS, [illegible] of the No. 2 Feedwater Startup Valve and loss of [illegible] No. 2 [illegible]. Approximately one minute later, low level in the No. 2 Steam Generator [illegible] full SFRCS trip, closing the Main Steam Isolation Valves (MSIV). The loss of heat sink for the reactor caused the RCS temperature, pressure, and pressurizer level to rise.

The RCS pressure increased to the pilot actuated relief valve setpoint (2255 psig) and the valve cycled open and closed nine times in rapid succession, failing to close on the ninth opening. Meanwhile, the reactor operator observed the pressurizer level [illegible] and manually tripped the reactor about one minute after MSIV closure (two [illegible] the transient). At this point the RCS pressure was approximately 2000 psig and decreasing while the pressurizer level had reached its maximum initial rise [illegible] 310 inches. The RCS pressure continued to decrease due to the open relief valve and upon reaching 1600 psig approximately three minutes into the transient, [illegible] Safety Features including high pressure (water) injection and containment [illegible].

Approximately [illegible] minutes into the transient the rupture disc on the pressurizer quench tank, which was receiving the RCS blowdown, burst. Bursting of the rupture [illegible] aggravated by the initiation of containment isolation, which had isolated the quench tank cooling system, resulting in expedited pressurization of the quench tank.

The RCS continued to blow down through the open pressurizer power relief valve and the quench tank rupture disc opening until primary coolant saturation pressure was reached, about six minutes into the transient. The formation of steam in the RCS caused an insurge of water into the pressurizer. This insurge and the high pressure water injection then restored pressurizer level to about 310 inches after [illegible] minutes into the transient.

Approximately thirteen minutes into the transient, the secondary side of the No. 2 Steam Generator went dry. About fourteen minutes into the transient, the operators noticed the low level condition and found that the auxiliary feed pump was operating at reduced speed. Manual control of the auxiliary feed pump was [illegible] and water level restored to the No. 2 Steam Generator.

At approximately 21 minutes into the transient, the operators discovered that the pressurizer power relief valve was stuck open. Blowdown via this valve was stopped by closing the block valve, thus terminating the reactor vessel depressurization. The RCS pressure recovered to normal and cooldown of the system followed.

The reason for the spurious "half-trip" of the SFRCS has not yet been determined. An extensive investigation revealed several loose connections at terminal boards, but nothing conclusive.

Investigation into the failure of the pressurizer pilot actuated relief valve revealed that a "close" relay was missing from the control circuit. This missing relay would normally provide a "seal-in" circuit which would hold the valve open until the pressure dropped to 2205 psig. Without the relay the power relief valve cycled open and closed each time the pressure of the RCS went above or below 2255 psig. The rapid cycling of the valve caused a failure of the pilot valve stem, and this failure caused the power relief valve to remain open.

It was determined that the auxiliary feed pump did not go to full speed because of "binding" in the turbine governor.

The transient was analyzed by the NSSS vendor and determined to be within the design parameters analyzed for a rapid depressurization.

With exception of the above noted malfunctions, the plant functioned as designed and there was no threat to the health and safety of the general public.

2. [illegible] Isolation Valves

On two occasions in July, [illegible] the [illegible] nuclear plant, a hydraulic feedwater [illegible] valve [illegible] close [illegible] of a close signal. All other equipment [illegible] normally.

The [illegible] July 6, 1977, [illegible] improperly [illegible] solenoid in the hydraulic actuator. Investigation of the second failure indicated [illegible]

POOR ORIGINAL

Failure of the valve to close was caused by the [illegible] regulator [illegible] and failing to close down to regulate the pressure. This caused the hydraulic system on the valve to be drained down to a point that the valve would not operate. Inspection of the regulator revealed that a locking screw on the regulator adjusting knob was loose and would allow the knob to vibrate to any position. With the regulator improperly set it would not close down to regulate pressure and would allow the hydraulic fluid to drain before the hydraulic operator could function. A similar problem was discovered on two other valves, although the maladjustment was not sufficient to prevent those valves from operating.

All the regulators were reset and the adjusting knobs were locked in place so that they could not vibrate loose. The isolation valves were tested satisfactorily following those adjustments.

1. Off-Gas System Valves

At the Oyster Creek Nuclear Generating Station on August 27, 1977, the reactor building ventilation system isolated and the standby gas treatment system (SGTS) automatically initiated.

Investigation revealed that at approximately 1850 hours a station employee performing housekeeping duties in the main control room accidently caused the augmented off gas (AOG) mode switch to move from "isolate and bypass" to the "isolate" position. This resulted in the off gas valve and the off gas drain valve going closed, and since the AOG was not in service the gas flow was stopped. The isolation of the reactor building ventilation system and initiation of the SGTS occurred at 1905. The two off gas valves were opened four minutes later and the SGTS was secured. The reactor building ventilation system was returned to normal at 2000 hours.

The off gas drain valve did not seal properly and was not leak tight. This condition allowed the gaseous radioactivity within the isolated off gas system piping to travel up through the stack sump in the stack base and fill the air space in the ventilation tunnel. When the radiation level in the reactor building ventilation duct reached a level of 17 mr/hr the monitors located next to this duct initiated the SGTS.

The safety concern associated with this event is the possibility of a submergence dose a person would have received from the radioactive gaseous atmosphere if they were in the tunnel area. The atmosphere in the tunnel area is processed through the radwaste ventilation system, which contains both roughing and absolute filters, prior to exhausting through the stack which is monitored. The maximum radiation level [illegible] the tunnel was 76 mr/hr.

No personnel exposures or releases to the environment resulted from this event. The licensee is investigating the feasibility of installing an alarm to alert operations personnel to the closure of the off gas valve when the AOG is out-of-service.

POOR ORIGINAL

ENCLOSURE 14

Therefore, a postulated failure of the power supply to dc distribution panel 2B would result in an inability to start the A train motor driven pump and a loss of speed control for the turbine driven pump.

One of the design bases for the aux FW system, as described in the FSAR was that in the event of a steam or FW line rupture and a single failure, 2 out of the 3 aux FW pumps must start and deliver FW to the 3 SG's. Since the above single failure associated with the dc distribution panel 2B would result in the inoperability of 2 pumps, this was in violation of the design bases of the FSAR.

The power supply to the turbine-driven aux FW pump was to be removed from dc distribution panel 2B and be provided from 120 V ac distribution panel 2J via a battery charger. The charger was to be safety-related and designed to supply 3A @ 125 V dc under continuous operation. The 120 V ac distribution panel 2J was powered from inverter 2F, which in turn could be powered from A train ac or dc power supplies with automatic switchover capability. Thus, a failure of A train 125 V dc power would not affect the operation of the turbine-driven pump and all design bases for the turbine-driven pump would be met.

Subsequent to the above modifications made in Dec 77 discussions with the NRC identified different aspects of the original problem concerning the dc power supply to the aux FW system not previously considered. It was determined that under simultaneous loss of off-site power (LOSP) and a high energy pipe break, the single failure (inadvertent trip) of the 125V dc Battery 1A breaker 72-LA05 would result in the following: 1) DG 1-2A and 1C would not be able to start since dc control power was not available. 2) Train A motor driven aux FW pump would not start due to the LOSP and the inability of the diesels to start. 3) The LOSP, the inability to start the A train diesels, and the failure of 72-LA05 would remove all ac and dc power supply to Inverter 1F, which powered the turbine speed control. The turbine driven aux FW pump would be inoperable.

For the above events, only the B train motor driven aux FW pump would start. Similar failures were postulated for the B train.

To meet the system design criteria and correct the above noted problem, the following modifications were made during a scheduled outage in Apr 78: 1) The control circuitry for the turbine driven aux FW pump steam, admission valves HV-3226-A, HV-3235A-A, and HV-3235B-B was modified to provide an automatic opening signal from both solid state protection panel Train A and Train B (cross logic). 2) The dc supply to Inverter 1F was disconnected from Bus 1A breaker 72-LA16 and was connected to Battery 1A through a pair of fuses upstream of battery breaker 72-LA05. This would avoid any interruption of power to inverter 1F in the event that breaker 72-LA05 tripped open. 3) The power supply to steam admission valves HV-3226-A and HV-3235-A was not furnished from the same dc feed that supplied power to Inverter 1F. 4) The power supply to steam admission valve HC-3235B-B was then furnished from the Train B dc feed upstream of breaker 72-LB1B through a pair of fuses.

Subsequent to completion of the modifications, the FW system was satisfactorily tested. (ftt,fvu)

N 94. OPEN CIRCUITED RELAY COIL REPLACED IN VALVE CONTROL CIRCUIT

N North Anna 1 - Apr 78 - hot standby

During a main steam valve performance check, trip valve TV-MS-101C would not close from the H bus control board and had to be closed from the J bus control board. Troubleshooting revealed an open coil in a control circuit aux relay on the H bus control board. The H relay coil was replaced and the control circuit tested satisfactorily.

The primary function of trip valve TV-MS-101C was to shut off the steam flow automatically in case a rupture occurs in the main steam line between it and the turbine. Normal operation for TV-MS-101C was the automatic closure in the event of a line break outside containment. Also, it could be closed manually by push button in order to test valve seating, etc. This secondary function was operated through a completely separate circuit from the primary function, using a control relay for seal-in of the manual "Close" function. Thus, at all times throughout this occurrence not only could TV-MS-101C be operated automatically, but could operate manually off of J bus control board as well. (fvs)

N 95. SFRCS, PRESSURIZER RELIEF VALVE & AUX FW PUMP CONTROL SYSTEM FAILURES - SCRAM, PRESSURE/TEMPERATURE TRANSIENTS

N Davis-Besse 1 - Sept 77 - 9% power

At the time this incident occurred, the reactimeter data logging system was in service which recorded at high speed a number of system parameters that would not have been available on such a time base through normal station instrumentation and records. The event started at time 21:34:20 (T = 0) on 24 Sept. The plant was in Mode 1 with power at 263 MWt. The turbine had been shutdown earlier to repair a leak in the main steam line at an instrument connection between the turbine stop valves and the HP turbine. At this time a 1/2 trip of the Steam and FW Rupture Control System (SFRCS) was initiated by an unknown cause. The trip closed this startup FW valve to SG No. 2 and stopped all FW to the SG (at this low power level the main FW block valve was closed, isolating the main FW control valve). The low level alarm was reached in SG No. 2 at T = 24 sec. Before the operator could identify and correct the problem, this low level correctly produced a full trip of the SFRCS. This trip closed the MSIV's and FW isolation valves in both SG's (T = 38). SFRCS initiation also started both aux FW pumps. Pump No. 1 performed as intended, however, aux FW pump No. 2 only came up to 2600 rpm, insufficient to feed SG No. 2.

The loss of FW to both SG's caused an increase in RCS temperature, which resulted in an increase in pressurizer level and RCS pressure. At 2255 psig the pressurizer electromatic relief valve received an open signal. During the next 40 sec, it cycled close-to-open 9 times and then remained open. This provided a continuous vent path from the pressurizer to the quench tank. When pressurizer level rose to 290 in., the operator manually tripped the reactor (T = 1 min 47 sec). Energy escaping through the electromatic relief valve and main steam relief valves caused a rapid cooldown and depressurization of the RCS. RCS pressure dropped to 1600 psig (T = 2min 51 sec) initiating the Safety Features Actuation System (SFAS). This started the HP injection pumps and closed certain containment isolation valves. With the electromatic relief valve still open, the quench tank rupture disc ruptured (T = 6 min), relieving steam into the containment.

When the RCS pressure decayed to ~1500 psig full HP injection flow was established and started to raise pressurizer level. At T = 6 min 14 sec the operator stopped the HP injection pumps. (The operators had been heavily involved before this time in regaining seal injection flow to the reactor coolant pumps (RCP) which had been stopped by the SFAS actuation. By T = 5 min 20 sec the appropriate SFAS signals had been overridden and normal flows restored to the seals of the pumps). RCS pressure continued to decrease until saturation pressure was reached and steam began to form in the RCS (~T = 8 min). This caused an insurge of water into the pressurizer and the pressurizer level went off scale at 320 in. During this level increase the operator, seeing average RCS temperature and pressurizer level increasing, stopped one RCP in each loop (T = 9 min) to reduce the heat input into the RCS. Due to decreasing pressure in SG No. 2, the SFRCS system gave a low pressure block permit signal at T = 14 min 13 sec. This alerted the operator to the low level and feed condition of SG No. 2. He blocked the low pressure trip (T = 15 min 15 sec), took manual control of the speed of aux FW pump No. 2 which commenced full FW flow to the SG. (T = 16 min.) The operator saw the rapid addition of cold FW into SG No. 2 was dropping the RCS temperature and reduced the FW flow.

At ~T = 21 min, it was determined the power relief valve was remaining open and the block valve was closed, isolating the power relief valve on the pressurizer and stopping the venting of the RCS to the quench tank. At T = 31 min pressurizer level came back on scale. At T = 41 min the operator started a 2nd makeup pump to try and stop the level decrease. This additional cold water started the RCS on a slow decreasing temperature transient. At T = 43 min. pressurizer level reached the low level interlock and cut off the heaters. At T = 49 min the operator started a HP injection pump to try and stop the decreasing pressurizer level. The level and pressure in SG No. 2 again decreased to the point where the SFRCS gave a low pressure block permit signal. The operator again blocked the trip and, through manual speed control of its aux pump, restored level and pressure in SG No. 2 (T = 51 min). With pressurizer level well on its way to recovering, the operator stopped the HP injection pump (T = 53 min 24 sec). At T = 57 min. he restored reactor coolant makeup flow to normal. This stopped the slow decreasing reactor coolant temperature transient which started at T = 41 min. All plant parameters were now fully under control and the plant was brought to a steady state condition, and a normal plant cooldown started.

During this rapid depressurization event the RCS pressure dropped from ~ 2300 psig to ~ 930 psig in 7 1/2 min and gradually recovered to 1800 psig in 2 hr. During this 7 1/2 min the reactor coolant outlet temperature dropped at varying rates from ~ 580°F to ~ 532°F. About 30 min after this initial temperature change, a 2nd slower and smaller temperature change from 540°F to 505°F occurred over a 21 min period. Following this 2nd temperature decrease, the temperature gradually increased over a 2 hr period to 528°F. The reactor inlet temperature changes and durations were similar to those of the reactor outlet temperature. The depressurization resulted in steam formation in the RCS, but evaluation showed there was no appreciable boiling in the core. The pressure/temperature transients in the RCS components including the SG, RCP's and fuel were severe, but analysis and subsequent pump testing showed that these transients were within the design allowables and that no detrimental effects were to be expected on the primary system, pumps or fuel. All safety systems performed their design functions in the proper manner. Operator action was timely and proper throughout the sequence of events.

The major physical damage from the incident was to the reflective metal insulation on the lower part of SG No. 2, which received the jet of steam coming from the pressurizer quench tank. A ventilating duct in the area of the quench tank was dimpled. Entry into the containment was made ~ 8 1/4 hr after the reactor trip for cleanup operations.

Prior to entering containment, air samples for R/A gases and particulates indicated no airborne radioactivity. Dirt was found on the walkways on elevation 565ft and 585ft in the east side of containment, and on 565 ft elevation the floor was completely covered with dirt which was washed down during the period when steam was being released from the quench tank and condensing on containment structures. The dirt was contaminated with activation products of Cr-51, W-187, Co-58, Zn-67, and Na-24 which were present in the RCS. Smears of the dirt indicated levels up to 40,000 dpm/100cm^2. Decontamination was accomplished by shoveling gross amounts of dirt into drums, and vacuum sweeping the remainder. The level of contamination in walkways was reduced to meet clean area limits. Air samples collected during the decontamination work verified that contamination did not become airborne.

The pressurizer quench tank rupture disc ruptured from high pressure. The steam from the quench tank vent damaged metal reflective insulation on the lower part of SG No. 2. A ventilating duct above the quench tank was bent, and a ventilation louver was damaged. Several pressurizer heater cables were dampened from the moisture, causing low insulation resistance. Two light fixtures and a combustion detector sensor in the quench tank area were also damaged. All damaged equipment was repaired or replaced. Instrumentation and equipment in the area was checked or tested for possible damage from the steam and water. Twenty-three panels of reflective insulation were replaced. The other affected panels were straightened, repositioned and reinstalled on the SG. The wet pressurizer heater cables were baked, heated or air dried to restore insulation resistance. Four shorted cables were to be replaced. A new rupture disc was installed on the pressurizer quench tank. The deformed ventilation duct was straightened and a new louver was installed in the duct. The damaged light fixtures and combustion detector were replaced.

The aux FW pump No. 2 failed to accelerate to the normal speed of 3600 rpm. The MSIV opened properly and the pump came up to ~2600 rpm. The governor, a Woodward Type PG-PL with a speed changer motor driving the manual speed setting knob, was calling for a higher speed (the speed changer motor was turning in the "increase" direction). As required, the governor was left in accordance with procedures with the speed adjustment at the "full speed" position when the pump was shutdown. When the pump was called on to auto-start with SG level below setpoint, the speed changer motor continued to drive, through a slip clutch, in the "increase" direction. However, the speed setting mechanism was already at its mechanical high speed stop applying a binding torque to the "T" bar, a portion of the "feed back" linkage, not allowing it to drop down and allow the piston rod to move down in the increase speed direction. The undesired binding in the feedback linkage gave the governor a false signal that the turbine was at the desired speed. Once the torque was removed, by operator remote manual action, from the "T" bar, the "T" bar dropped down and the pump turbine proceeded to the high speed stop (~3600 rpm). The type PG-PL governors were returned to the Woodward factory and one of the governors was placed on the test stand. While observing the operation of the speed setting linkage, it became evident that removal of a simple link from the speed setting pilot valve (plunger) to the floating lever would allow removal of the bellows, coupling spring, low speed pin, "C" link and dashpot plug in the speed setting pilot valve sleeve. This would allow the speed setting pilot valve to overtravel when the motor was set in a high speed condition with the speed setting servo at the minimum position. The governor parts removed were for the pneumatic speed setting mechanism and because this governor was servomotor controlled were not needed for proper governor operation. The required parts were manufactured, the unneeded parts removed and the governors were reassembled. The governors were tested at the factory and the tests confirmed that the modifications did remove all possibility of the undesired binding of the governors. Surveillance testing at the station had also confirmed that the governors functioned properly. See IX.D.74, 82 & 89 for other problems with speed control of these turbines.

When the RCS pressure reached the setpoint for the pressurizer power relief valve, 2255 psig, the valve opened properly. However, there was a seal-in relay which then kept the valve open until pressure was reduced to a lower "reset" pressure (2205 psig). This seal-in relay that controlled the closing of the valve was missing from the circuit. Without the relay, the valve reclosed as soon as pressure decreased below the "open" setpoint. The result was open-close cycles as pressure went above and below the "open" setpoint pressure instead of one or two longer blows to relieve the high pressure down to the "reset" pressure. After ~9 open-close cycles the power relief valve remained in the open position. The valve was completely disassembled. The seats on the nozzle and main valve disc were lapped. The pilot valve was found stuck in the open position and it was thought that the pilot stem was bent so the pilot stem was replaced and the nozzle guide area was cleaned up to remove the marks from the galling of foreign material. The valve was reassembled and stroked 6 times with a pressurizer pressure of ~600 psi. During this testing the pilot valve again stuck and the isolation valve had to be closed.

The valve was again disassembled and under closer observation it was found that the pilot valve stem was moving too far (3/8 in. vs 1/8 in. desired). It was also found that the clearances between the pilot stem and the nozzle guide were too small (.0005 in. vs desired minimum of .001 in.). The clearances were opened up and the stroke of the pilot was shortened by adjustment of solenoid position. The valve was tested again successfully by stroking it 12 times at a pressurizer pressure of ~900 psi and one time at a pressure of 1200 psi.

The SFRCS was checked for loose terminations. All input devices were calibrated and the appropriate setpoints were checked. The SFRCS cabinet C5792 for logic channels 2 & 4 was tested for proper input and output signal levels. The SG level instrumentation was calibrated and checked for noise spikes. Several 6 channel chart recorders were patched into the SFRCS for continuous monitoring.

On 23 Oct, the SFRCS again tripped from a spurious signal. The Startup FW Valve on SG No. 2 went closed. This ultimately resulted in a valid SG low level trip input to the SFRCS and the system functioned as intended. This was the first spurious trip received after the chart recorders had been connected to the SFRCS. All information on the charts could be explained except for a problem on SFRCS logic Channel 4 computer alarm, P680. (LOW MAIN STEAM PRESSURE TRIP). This particular channel was intermittently failing, giving spurious trip indications. Of the 48 total chart recorder channels, this was the only one that had failed. Their investigation concluded the problem was internal to the system. In examining the logic control diagram, it was determined 3 IC "chips", 2 input buffers and associated wiring could have caused the fault. These components were replaced with the exception of the interconnecting wiring. The wiring and buffer connections were visually inspected, and no faults were observed. A functional logic test was performed and the system responded satisfactorily.

The vendor, Consolidated Controls, performed a response time check on both input buffers in question. This test showed no defects. They continued to monitor one of the two input buffers in a test set. Failure of one input buffer did occur on the test set, which indicated that this was the cause of the 1/2 trip. They checked the logic system with an oscilloscope looking for any erratic, noisy points, but everything tested appeared to be trouble free. The two input buffers were undergoing further tests and evaluation, while the 3 IC chips were returned to the manufacturer for evaluation. A study was also conducted to see if any single 120 Vac or 125 Vdc fault induced voltage dip could have caused the 1/2 trip on both MSIV's and closed the SG-2 SU control valve. This study revealed that no single fault on these power supplies could have caused this problem.

The following changes were made to the design of the SFRCS: 1) Annunciator windows were added where computer alarms existed for SG Level Half/Full Trip for both Channels 1 & 2, Main FW dp Half/Full Trip for both Channels 1 & 2, and Loss of 4 RCP Trip. 2) A new annunciator and computer alarm were added for a SFRCS Full Trip, and 3) The resetting of all SFRCS related alarms was to be delayed long enough to allow the computer to record the event.

(fxc)

July 78

ENCLOSURE 15

Nuclear Power Experience Inc.

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Listed below are the headlines from all additional or revised items in this month's "Latest Month Operating Experiences" packet. Subscribers are encouraged to reproduce this list for distribution to interested personnel.

Items marked "ALERT" are those the NPE staff believes are significant from outage causing, generic, safety, etc. standpoints.

BWR PROBLEMS IN JULY '78 ISSUE

I. FUEL

- 44. FA's leaked - hydride & pellet clad interaction failures----Quad Cities 1 & 2
- 45. Pellet-clad interactions -leakers----Dresden 2 & 3

III. REACTOR VESSEL

- 28. Recirc nozzle indications-----Hatch 1
- 29. Cracked instrument and head spray nozzles-----Millstone 1
- 30. Thermal cycling - CRD return line nozzle indications------Peach Bottom 3

V RECIRCULATION, STEAM & RELIEF

C. RELIEF & SAFETY VALVES

- 200. Worn seating surfaces in MSIV's and ventilation valves-----Browns Ferry 2
- 201. MSIV disc separated from stem-----FitzPatrick
- 202. Valves relieved - pilots replaced-----Fitzpatrick
- 203. Relief failed open - steam cut pilot and 2nd stage discs-----Millstone 1
- 204. Relief valve vibration - broken welds, worn piston rings-----Quad-Cities 1
- 205. Addition to V.C.193 - valve casting indications-----Browns Ferry 1 & 2

VI. TURBINE CYCLE SYSTEMS

C. CONDENSERS

- 47. Sticky solenoid valve - SJAE suction valve failed to close-----Quad-Cities 2
- 48. Binding in air removal valves-----Cooper
- 49. Tube leaks, missing plugs-----FitzPatrick

VII. SAFETY SYSTEMS

A. ISOLATION COOLING

- 65. Torque switch failed, mis-positioned limit switch - RCIC valve failures-----Quad-Cities 2
- 66. Dirty switch contacts - loss of RCIC turbine speed control-----FitzPatrick
- 67. Valve leakage corroded RCIC actuator-----Brunswick 1
- 68. Dirt in RCIC turbine ball and tappet assembly, out of adjustment torque switch-----Quad-Cities 1

E. HIGH PRESSURE COOLANT INJECTION

- 139. Mechanical interference in check valve-----Browns Ferry 2
- 140. Suction valve motor saturated with grease - motor burned up-----FitzPatrick
- 141. Out of adjustment torque switch - steam valve failed closed-----FitzPatrick
- 142. Worn torque switch - suction valve would not close-----Quad-Cities 1

VIII. AUXILIARY SYSTEMS

A. REACTOR WATER CLEANUP

- 42. RWCU valve operator limit switch failed-----Arnold
- 43. RWCU valve torque switch failed - motor burned up, excessive cooldown-----FitzPatrick

C. MISC.

- 133. Open drain valve omitted from drawing, inadequately torqued drywell head bolts-----Hatch 1
- 134. Steam line drain valve bonnet and seat leakage-----Dresden 3
- 135. Inadequate drains - potential flooding of ECCS equipment rooms-----Hatch 1 & 2, BWR's in general
- 136. Erosion in HPCI and RCIC steam supply drain lines-----Monticello

IX. INSTRUMENTATION & CONTROL

E. SAFETY SYSTEMS

- 355. Additional information - missing relay locking springs——Arnold
- 357. Defective HPCI flow controller module-----Peach Bottom 3
- 358. Failed fuse in LPCI valve controller-----Quad-Cities 2
- 359. Condensation in drywell pressure sensing lines-----Quad-Cities 1 & 2
- 360. Loose instrument air line fittings - high O_2 conc.-----Brunswick 1
- 361. Crud on core spray pump pressure switch-----Dresden 2

362. Moisture shorted SGTS temp switch - fire deluge system actuated onto charcoal filter -----Brunswick 2

ALERT → 363. Broken core spray pump control switch, no lockout annunciation-----Hatch 1

C. MISC

176. CAM sample pump failed-----Browns Ferry 3
177. Reactor building radiation monitor relay failed-----Browns Ferry 2
178. Leaking fittings, stuck valves, condensation - radiation and H_2-O_2 monitors failed -----Brunswick 1 & 2
179. Cracked pump shaft, water in sample line, stuck valves - low flows in CAC monitors -----Brunswick 1 & 2
180. High output from O_2 sensor-----Browns Ferry 1

XI. ELECTRICAL SYSTEMS

A. EMERGENCY POWER

210. DG pilot air regulating valve leaked - misaligned diaphragm and o-ring-----Dresden 1
211. Shorted DG fuel pump contactor diode - blown fuses, relays damaged-----Dresden 1
212. Damaged DG lube oil pump coupling, incorrectly wired pressure sensor-----Dresden 1
213. Diesel oil tank level control valve stuck open - low tank fuel level-----Dresden 3
214. Governor supplied inadequate fuel - gas turbine failed to start------Millstone 1
215. Incorrect MG set overspeed stop settings-----Cooper-----BWR's General

ALERT → 216. Heat sensitive battery charger transistors-----Hatch 1 & 2

ALERT → 217. Vibration in switchgear panels, possible DG failure - design problem-----Hatch 1 & 2

B. OTHER ELECTRICAL

172. Defective transistor in RCIC reset circuit - inverter failed-----Peach Bottom 2
173. HPCI inverter zener diode failed-----FitzPatrick
174. RHR valve controller aux contact failed - fuse blown-----FitzPatrick

ALERT → 175. Improper breaker insertion - misalignment-----Hatch 1 & 2

XII. LIQUID RADWASTE SYSTEM

→ 57. Radwaste transfer pipe froze & fractured - release-----Oyster Creek
58. Concentrator regulator valve leaked, radwaste drawn through temporary hose - overpressurization, release-----Brunswick 1

XIII. GASEOUS RADWASTE SYSTEM

107. Modifications to prevent offgas explosions-----Brunswick 1 & 2
108. Lube recirc system valve failed - sample pump tripped-----Oyster Creek
109. Underground offgas line leaked------Hatch 1

XIV. BUILDINGS & CONTAINMENT

B. MISC.

199. Cooling air duct misaligned - high MSIV pilot valve temperature-----Quad-Cities 2
200. Deteriorated ventilation valve seats-----Browns Ferry 2
201. Purge valve actuator alignment key sheared-----Peach Bottom 2
202. Liquid nitrogen cracked inerting line - high O_2 concentration during repairs----- Brunswick 2
203. Swollen bushings - binding in vacuum breakers-----Dresden 2

XV. MISC SYSTEMS

86. Loose end nut allowed snubber rotation, fluid drained out-----Cooper
87. Inoperable hydraulic snubbers - replaced with mechanical units-----Dresden 3
88. Cotter pins missing from RBCCW HX snubber-----Browns Ferry 2
89. Deteriorated valve seats and o-rings, packing leaks, etc.-----Quad-Cities 2
90. Pipe vibration - disconnected snubber, failed o-ring-----Nine Mile Pt. 1
91. Seal deteriorated in LPCI snubber-----Dresden 3
92. Hardened snubber o-ring and seals, missing cotter key, damaged pivot pin----- Quad-Cities 1

ALERT → 93. Bergen-Patterson snubber test stand components damaged-----BWR's general

XVI. OPERATIONAL PROBLEMS

B. REFUELING

19. Fuel grapple switch was bumped - FA dropped------Peach Bottom 3
20. Refueling interlock bypassed, incorrect rod position indicated - rod was not fully inserted-----Browns Ferry 2

C. MISC.

413. Inadequate sampling - high R/A in waste sample tank-----Dresden 2
414. Core spray sparger break alarm card found pulled-----Arnold
415. Aux steam unavailable for N_2 vaporizer - high O_2 conc.-----Brunswick 1

PWR PROBLEMS IN JULY 78 ISSUE

IV. CONTROL RODS & DRIVES
B. DRIVES

71. CRD's reconditioned following reactor trip-----Arkansas One 1
72. Setscrew loosened in CRDM brake assembly-----Palisades

V. REACTOR COOLANT SYSTEM
A. PUMPS
69. RCP seal package failed-----Indian Pt. 2
70. RCP seal line welds cracked - cyclic fatigue-----Calvert Cliffs 2
D. STEAM GENERATORS
181. Dented tubes plugged-----Surry 2
182. Tube denting, hourglassing-----Indian Pt. 2
183. Tube denting - support plates modified, tubes plugged-----Millstone 2
184. SG tube sleeving-----Oconee 1, 2 & 3
185. Tubes leak - loose plug found - loose part in RCS-----Turkey Pt. 4
186. Tubes leaked - fatigue, weld cracks-----Oconee 2
187. Leaking tube plugged-----Pt. Beach 1
E. PRESSURIZER
17. Low pressurizer pressure - spray valve seal rings scored-----Farley 1 (additional infromation)
21. Valve leaked at seal weld-----Conn. Yankee

VI. SAFETY SYSTEMS
D. STEAM
160. Steam dump valve stuck open - SI-----North Anna 1
161. Main steam relief valves adjusted using wrong hydroset curve-----Rancho Seco
E. CONDENSATE & FEEDWATER
156. Additional information - excessive FW valve closure time-----Crystal River 3
162. Loose bonnet bolts, scratched gasket - aux FW valves leaked-----Davis-Besse
163. Foreign object damaged valve seat-----Indian Pt. 3

VII. SAFETY SYSTEMS
A. EMERGENCY CORE COOLING
167. SI system weld leaked-----Calvert Cliffs 2
168. BIT recirc valves leaked - boron diluted-----Farley 1
169. Trace heater failed - valve leaked-----Surry 2
170. Undersized Limitorque motor failed - construction error-----Salem 1
ALERT → 171. Addition to VII.A.157 re LHSI pump problems-----North Anna 1 & 2
D. CONTAINMENT ISOLATION

21. Faulty torque switch on Limitorque-----Oconee 3
22. Solenoid valves stuck - oil in instrument air-----Zion 1
E. MISC.
22. Control room emergency air header leaked - pipe coupling cracked-----Surry 2
23. Fire pump diesel battery electrolyte low, voltmeter faulty, jacket water heater replaced -----Davis Besse 1

VIII. AUXILIARY SYSTEMS
A. COOLANT VOLUME, PURIFICATION, CHEMICAL, SAMPLING

278. Inconel sheathed trace heater installed for higher corrosion resistance-----Zion 1
279. Charging header flow instrument line weld cracked - release-----Calvert Cliffs 1
280. Charging pump vibration cracked pipe weld, valve block-----Ft. Calhoun 1
281. Charging pump recirc orifice bypass valve eroded - design changed-----Conn. Yankee
ALERT → 282. SI pumps failed - shaft vibration, bearing wear-----Beaver Valley 1 & North Anna 1
B. AUXILIARY COOLING
179. Service water HX tubes leaked-----Calvert Cliffs 1
180. Pump impeller eroded - vibration damaged bearings-----Surry 2
181. Limitorque switches cleaned, adjusted-----Cook 2
182. Service water system check valve rusted-----Davis Besse 1

IX. INSTRUMENTATION & CONTROL
A. NUCLEAR INSTRUMENTATION
55. Intermediate range log current amplifier failed-----Beaver Valley 1
56. Source range channel failed intermittently - detector replaced-----Cook 1
57. Noise spike tripped power range channel - reactor tripped-----Three Mi. Is. 2
58. Faulty source range detector replaced-----Zion 2
59. Proportional counters failed - generic problem implied-----Calvert Cliffs 1
60. IRM bistable card defective-----Prairie Is. 1
61. High voltage cable connection loose on power range detector-----Millstone 2
B. REACTOR PROTECTION
281. Steam flow instrument summator replaced
282. dp unit replaced in pressurizer level transmitter-----Farley 1
283. RCS loop overtemperature ΔT instrument module failed-----Cook 2

184. Spurious steam flow signal - SI-----North Anna 1
185. Strain gage failed in SG level transmitter-----Salem 1
186. Pressurizer level transmitter equalizing valve packings leaked-----Cook 2
187. Steam flow transmitter line leaked-----North Anna 1
188. Thermal margin/LP calculator module failed-----Calvert Cliffs 1

C. REACTOR CONTROL
89. CEA position indication channel reed switch failed open-----Millstone 2
90. Temporary recorder load affected RPI readout-----Cook 1

D. TURBINE CYCLE
94. Open circuited relay coil replaced in valve control circuit-----North Anna 1
95. SFRCS, pressurizer relief valve & aux FW pump control system failures - scram, pressure/temperature transients-----Davis-Besse 1

E. SAFETY SYSTEMS
ALERT → 198. Additional information re terminal blocks——Conn. Yankee
199. Faulty input buffer tripped SFRCS - new annunciators, alarm added-----Davis-Besse 1
200. Pressure instrument module failed-----Calvert Cliffs 2
ALERT → 201. Addition to IX.E.183 re terminal blocks-----Cook 1 & 2

F. PROCESS SYSTEMS
21. Pressure transmitter sensing line leaked - personnel contaminated-----Arkansas One 1
22. Service water pump control switch contacts dirty-----Zion 1
23. Service water valve motor control power fuse blew-----Robinson 2

X. FUEL HANDLING FACILITIES & SYSTEMS
52. FA damaged during exam in spent fuel pool-----Oconee 1

XI. ELECTRICAL SYSTEMS
A. EMERGENCY POWER
242. DG air start control valve part missing - maintenance error-----Farley 1
ALERT → 243. Emergency diesel inadequate for LOCA - reduced loadings evaluated-----Conn. Yankee

XV. MISC. SYSTEMS
139. Snubber o-ring failed——Calvert Cliffs 2
140. Demineralizer waste neutralizing tank leaked, low pH - corrosion-----Calvert Cliffs 1
141. Bergen-Patterson series 25000 hydraulic test stand components damaged-----PWRs General
142. Hydraulic snubbers leaked - replaced with mechanical-----Zion 2
143. Degraded snubber seals replaced-----Kewaunee

XVI. OPERATIONAL PROBLEMS
B. REFUELING
ALERT → 36. Technicians exposed to 17 and 27 rem during spent fuel transfer operations (revised)—Trojan
37. Spent fuel moved with reactor building purge filters inoperable-----Oconee 2

C. MISC.
591. Guard closed charging flow control valve-----Zion 1
592. Premature jumper placement - DG cooling pump locked out-----Prairie Is. 2
593. Instrument room purge valves left open with R/A air pump secured-----Cook 1
594. Gas pressure to isolation valve seal water tank secured-----Zion 1
595. Safeguards bus lost - operator error-----Prairie Is. 2
596. R/A monitor operated without filters-----Zion 1
597. Wrong hydrogen dilution blower discharge valve tagged out-----Davis-Besse 1
598. Seismic restraint missing - removal unexplained-----Trojan
599. Level instrument failed - operator used improper blowdown procedure-----St. Lucie 1
600. RHR vent valve opened - containment violation-----Kewaunee
601. LP injection cooler flow throttled - procedure error-----Oconee 2
602. Snubber stud & nuts missing-----Palisades
603. Service water system redundancy lost by improper tagging-----Maine Yankee
604. AFP tripped on overspeed - governor limiter readjusted - valving error-----Robinson 2
605. Drain valve left open - RCS flow lost-----Trojan
606. RCS pressure low - pressure switch mispositioned-----Zion 1
607. DG oil pressure gage line leaked following calibration - loose fitting-----Beaver Valley 1

ENCLOSURE 16

B&W User

1-351.4

Babcock & Wilcox

Power Generation Group

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1-N Capture

1-RDH

1-El Supt

1-Gm

February 3, 1978

To: B&W User's Group Distribution*

Attached is a copy of the minutes of our User's Group meeting on November 15 and 16, 1977.

Very truly yours,

W. A. Cobb

W. A. Cobb
B&W Representative
B&W User's Group

WAC:dmd
Attachments

*Per attached distribution list.

REV 5 [illegible]

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MINUTES OF MEETING - B&W USER'S GROUP

NOVEMBER 15 & 16, 1977

GENERAL

The B&W User's Group met on November 15th & 16th at the Twin Bridges Marriott Hotel in Washington, D.C. A copy of the list of attendees is attached as Enclosure 1. In general, the meeting followed the previously prepared agenda, a copy of which is attached to these minutes as Enclosure 2. Mr. W. A. Cobb of B&W chaired the meeting in the absence of Mr. J. G. Evans, User's Group Chairman.

MEETING OF NOVEMBER 15, 1977 (FIRST DAY OF MEETING)

OCONEE OTSG TUBE PROBLEM

C. W. Pryor of B&W made a presentation on the OTSG tube problem. Mr. Pryor described the eddy current inspection program which had been conducted at Oconee as well as Three Mile Island and SMUD. Tubes inspected by eddy current were identified as to location within the steam generators along with those tubes in which indications of greater than 20% of wall thickness had been identified and those having indications of greater than 40% of wall thickness. Mr. Pryor also identified those tubes which had been plugged as well as those which have been stabilized (strengthened by insertion of a solid rod within the tube). B&W's recommended standard tube pattern for eddy current inspection was also presented. Mr. Pryor indicated that most eddy current indications were found in the proximity of the open tube lane which was provided for inspection on the earlier 177 units. Indications were primarily along this open tube inspection lane in the area between the upper tube support plate and the upper tube sheet. Most indications were immediately adjacent either to the tube support plate or the tube sheet. Mr. Pryor also described the vibration test program which had been conducted at Oconee and the test program which is planned on TMI-2. It was further pointed out by Mr. Pryor that B&W had previously conducted meetings to describe the problem in comprehensive fashion to all of the operating plant owners and that later presentations were planned for 205 plant owners.

Following this presentation, Mr. R. J. Baker of B&W, Nuclear Service Department, described field operations relating to the OTSG tube problem. Mr. Baker's presentation covered methods of plugging tubes & stabilizing tubes along with the field problems encountered in this work. He also described tube removal operations where tubes are removed intact for examination of cause of defect. The presentation covered operations at Oconee, Three Mile Island, and SMUD. Of particular interest was the problem with radiation level in the SMUD generators.

REFUELING EXPERIENCE

Jim Phinney of B&W described the refueling experience on B&W units during the last year. Refueling work was reported to require thirty-three (33) days if no additional work was required. However, an average of thirty-one (31) days extension was required for additional work either on BOP items or NSS items. The major items causing outage extensions were the following: high reactor building activity, extended eddy current inspection, OTSG tube repairs, fuel element bow and twist damage, fuel handling equipment failures, RC pump seals, turbine problems, seal plate leakage problems, stator problems, and polar crane problems.

B&W's program to improve reliability was described. Major steps in the action plan include collection of operating data on reliability, an action plan for availability improvement, equipment upgrading as indicated by field reliability data, improved services to customers, and a new B&W Spare Parts Center to better address the utilities' needs. Mr. Phinney also reported on specific reliability items as follows:

(1) Seals - B&W's 875-8-3 seal for 177 units is expected to complete testing in mid-1978 and subsequently be available for use on operating plants. This seal is expected to provide significantly improved reliability.

(2) Fuel Handling Equipment - B&W is incorporating into new fuel handling equipment a continuous control rod guide brazement in the control rod handling mast.

(3) B&W has tested and is offering for replacement use a Target Rock spray valve. This valve is a sealed valve which has been tested for many cycles of operation.

(4) Graham Letdown Cooler - B&W has conducted work on explosive plugging of tubes and on sleeving. A final report is expected in December. If development is expected to be required, B&W will make a proposal to those utilities utilizing Graham coolers.

(5) ICS - B&W has visited a number of plants to assess "hunting" movement of the CRD's due to the ICS systems. A universal fix is very exclusive. There are some indications that different ICS settings at the various plants may cause a different response to the same fix. As a result, B&W will send block schematics to all of the operating utilities and ask for all ICS settings. The information will then be used to try to determine a common fix.

Jim also reported on the ERDA refueling outage availability program being conducted by B&W. Phase 1 covering the NSS has been completed with 11 to 12 critical path days saved. Phase 2 of this program to develop prototype implementation at Oconee is planned.

Mr. Phinney listed the following services as being available from B&W:

(1) Special tools
(2) Procedure improvements
(3) Special recovery teams (OTSG, RC pump seals, CRDM inspection and repair)
(4) Special services (video equipment, noise/vibration detection)
(5) Outage staff augmentation
(6) Hands-on work packages.

Finally, Jim made the following summary recommendations:

(1) Use B&W's refueling experience
(2) Use the recommendations from the ERDA study
(3) Utilize contingency planning
(4) Utilize outage critiques and outage reports
(5) Plan for good in-plant communications
(6) Provide standard health physics and security
(7) Make early commitment to contracted work
(8) Have decontamination facilities available.

RC COOLANT PUMP SEALS

Bill Spangler reported on RC pump seals and on the recent problem with RC pump gaskets. It was reported that the endurance test on the long-stack 875 seal had completed 7,000 hours with excellent results (the 875 short-stack which will be used as replacement seal for 177 FA size Bingham pumps is scheduled to go on test in early December). The results from the 875 long-stack seal indicate a possible lifetime of 3 to 5 cycles without maintenance.

Bill also reported on the test experience for the 950 seals which will be used on the 205 plants with Bingham pumps. Approximately 5,000 hours of testing has been completed on this seal with very successful results. John Anderson of Arkansas P&L inquired about tests being conducted on B-J seals. Bill responded that we haven't had as many problems with B-J seals and hence have no further development work underway. Mr. Anderson further reported a 200 to 300 psi cycling on the B-J seals. Mr. Bradham of Duke reported that the 875 seals installed in Oconee had only 1/3 to 1/2 the maintenance time of the previously installed seals.

Bill also reported on gasket leakage with Bingham pumps. It was reported that the problem was caused by insufficient gasket rebound for the flange motions caused by pressure and temperature gradients. The following fixes will be incorporated:

(a) Revised installation procedures
(b) Higher gasket density to improve resiliency
(c) Incorporation of a hard nose on the gasket
(d) New gasket filler material
(e) Higher bolt load (pre-load)

NUCLEAR PARTS CENTER

Mr. L. R. Weissert described the newly organized B&W Nuclear Parts Center. Lou described in some detail the organizational setup of the new center to serve the needs of the operating utilities. He set the following goals for this organization:

(a) To be on call and on time
(b) To provide fast response
(c) To provide updated parts manuals
(d) To assist in spare parts inventory planning and in planning for parts needed for outages

(e) To define interchangability of supplied parts
(f) To provide a parts locator service.

Mr. Weissert also expressed a desire to meet with utility representatives to discuss their inventory policy and develop a spare part plan with them. The Owners were asked for a contact within their organization for this function.

Mr. Rodriguez of SMUD requested that B&W develop a policy on B&W inventory of spare parts and to report this policy to the utilities with particular regard to the inventory of spare RC pumps or RC pump internals.

INCORE DETECTORS

Mr. E. S. Patterson of B&W described the design of the B&W incore detectors and a possible failure mechanism for the failures which have been encountered. The presumed mechanism postulates a defect in the outer sheath of the detector with RC water then causing stress corrosion cracking of the individual detector sheaths. He pointed out that while the mechanism explains the failure of the detector after water entry it does not explain the presence of initial defects in the detector sheath. He indicated the following steps which B&W has taken to improve the equipment for later applications:

(a) Better material control
(b) Increased inspection in fabrication
(c) Improved heat treatment of the individual detectors and of the final detector assembly
(d) Improved non-destructive testing during fabrication
(e) Closer follow of performance at individual operating plants.

Pat indicated a failure rate of approximately 1% at most operating plants, but approximately 5% of the Oconee units, which used earlier manufactured detectors. He further indicated that planning for supply of replacement detectors was important. Mr. Anderson of Arkansas P&L indicated a 15 month le[illegible] time for previously ordered detectors. Phinney of B&W indicated that instr[illegible]ions on checking the resistance of potentially failed detectors would be for[illegible]rded to utilities in the near future.

NI CALIBRATION

Mr. J. R. Smotrel of B&W made a presentation on NI calibration. The overhead slides used by Mr. Smotrel are attached as Enclosure 3. His presentation addressed the following major points:

(1) The need to maintain NI calibration
(2) The causes of changes to NI calibration
(3) Past events in discussion of this subject with the operating users
(4) B&W's current recommendations
(5) Further B&W program on NI calibration.

SITE PROBLEM REPORTS AND FIELD CHANGES

Mr. R. E. Wascher of B&W described the systems which B&W has in place for assessing the applicability of a site problem found at one site to all of the other B&W units. The system requires that an assessment be made and documented on each problem which arises. If the documented assessment indicates that the problem is applicable to a given plant, the problem is added as an outstanding problem to computerized reports which indicate the total number of problems outstanding against a given plant. The problems are thus maintained visible to management and can be expedited vigorously. The system likewise provides for generic handling of field changes.

RATCHET TRIP

Mr. A. W. Brown of B&W made the presentation on the ratchet trip problem. The overhead slides used by Mr. Brown are attached as Enclosure 4. Art indicated that a number of proposals have been made through operating plant customers for minimizing the possibility of ratchet trip. The last of these proposals was in process and should in the customers' hands imminently. The final quotation is for a system which detects the imminency of a ratchet trip and provides a conventional trip on such a signal to prevent damage to the lead screw and segment arms. The new system would cause the rods to drop only if they were commanded to move during the time that a fault existed which could cause a ratchet trip to occur.

ICS

Mr. R. W. Winks had been scheduled to make a presentation on the improvements to preclude hunting in the integrated control system. However, at the last minute Mr. Winks had been called to the Duke site on an urgent problem and was unable to attend. However, Mr. Phinney had earlier presented the essence of Mr. Wink's report (see report on refueling experience in these minutes).

MEETING OF NOVEMBER 16, 1977

The meeting consumed one-half day and was devoted exclusively to plant experience reports by the station superintendents. Resumes of their reports are presented below:

OPERATIONS AT OCONEE

Mr. O. S. Bradham of Duke Power Company gave the report on Oconee (Mr. Bradham's report was actually given on November 15, 1977 to permit his return to Oconee).

(1) Tube leaker on OTSG - Oconee II

(a) Leak determined through air ejector readings; some disagreement with steam line monitors.

(b) Leak apparently only 1 gpm; may be only gas.

(c) Turbine building sumps and releases not based on 1 gpm. Radiation seeping into concrete in sumps causing higher background. A recommendation was made that tube leaks should be considered in the design of the turbine building.

(d) Problems encountered were the following:

(1) Training people who do not normally work in radiation.

(2) No change rooms in area of turbine building.

(3) Problems with radiation monitoring and control of releases.

(2) Stator Problems

(a) The problem of valve leakage running down into the control rod drive stators was described. The problem was complicated by the fact that this is cromated water.

(b) The difficulties of changing CRDM stators when the drives were at approximately 120° to 130°F were described.

(3) RC pump seals - Ollie described problems with particles from welding processes which were not properly flushed from the system prior to operation.

(4) Mr. Bradham described the sources of reactor building radioactivity.

(a) RC system leaks
(b) Leaking fuel
(c) Velan valves
(d) Bingham RC pump gaskets leaking

(5) Duke is planning to change out all valves to utilize packless valves.

OPERATIONS AT THREE MILE ISLAND

Mr. G. P. Miller, Superintendent of Three Mile Island Station led off the report by announcing the appointment of Mr. J. P. O'Hanlon as Superintendent for Three Mile Island Unit 1. Mr. Miller then reported on progress at Three Mile Island Unit 2. The following items were reported:

(1) Fuel load is expected somewhat after the beginning of the year.

(2) The following was the chronology of events for 1977:

(a) ACRS hearings - early 1977
(b) RCS system filled - May 1977
(c) Public hearing - July 1977
(d) Hot functional test - finished October 1977

Mr. Miller reported that the biggest reamining problem involves the main steam line break analysis.

(3) Licensing examinations were passed by 12 CRO's; 2 SRO's must retake the examinations.

(4) There were two fires in Unit 2.

(5) Standardized tech specs must be used on Unit 2 causing a probable backfit on Unit 1 for uniformity.

(6) 450 people are employed in operations at the site, not counting security or training (50 to 80 guards are employed)

Mr. J. P. O'Hanlon reported on Three Mile Island Unit 1 as follows:

(1) Capacity factor has been approximately 75%.

(2) The following chronology of events was given:

February 1977 - Change to monthly turbine stop valve test at 50%.

March 1977 - Refueling and fuel shuffle required 8 weeks. Snubbers and OTSG eddy current tests lengthened the refueling.

July 1977 - Deluge system operated. There was a problem in maintaining vacuum due to shrimp intake into the conden er.

September 1977 - Valve failure caused acid breakthrough to OTSG. Ph was 2 or 3. Also, a high resistance connection to the RC pumps caused arcing and ultimate vaporization of the connector and a cable length. A generator ground fault also caused the unit to trip during this month.

October 1977 - The unit tripped due to an ICS signal convertor failure.

(3) Three Mile Island 1 will convert to standardized tech specs at the refueling outage in 1979. The increased surveillance testing identified by these specs would probably double the present required testing.

(4) On the OTSG's, 9 tubes were plugged. Only one or two required plugging, and the remainder were plugged for conservatism. GPU feels that the OTSG tube problem may not be generic and that the problem may be to differing layups of the generators and different operation of the emergency feed nozzles.

(5) TMI plans monthly vibration testing on the DH pump to assure that the problem which occured at Florida Power Corporation does not cause failure of the TMI pump.

CRYSTAL RIVER III - FLORIDA POWER CORPORATION

Mr. G. P. Beatty reported on operations at Crystal River III as follows:

(1) Licensed December 1976 based on standardized tech specs (338 surveillance procedures are required by STS).

(2) The fol'... chronology of events was reported:

Jan..., 1977 - Initial criticality

March 1977 - 100% power

May 1977 - Problem with governor valves on Westinghouse turbine. Ten day outage - borrowed replacement. Also during this month there was a salt water leak into the condensers causing four additional days outage.

June 1977 - Operated at 70-75% capacity factor. Experienced stator failures; replaced hot at approximately 130°F.

July 1977 - Experienced one or two additional stator failures. All stators were changed out from epoxy to varnish type. No subsequent stator problems occured. An expansion joint disintegrated on the turbine. 100% load rejection with no reactor trip was experienced.

(3) FPC instituted its own fix on the ICS to correct excessive control rod motion. This reduced rod motion per once every 4 or 5 hours. Handout on the fix was distributed (F. R. Fahland of B&W has a copy).

(4) A total of 350 modifications (MAR's) have been issued on Crystal River 3.

(5) A management consultant has recommended 34 more positions on the operating staff. This will bring the staff to 180 people not counting security or system maintenance.

(6) FPC allows the use of furmanite on the secondary side of the plant without engineering approval. One furmanite joint has leaked.

ANO #1, ARKANSAS P&L

Mr. J. W. Anderson reported on operations at ANO-1 as follows:

(1) Two rows of blades were cut out during refueling. Two high pressure heaters were out of service with tube leaks on the secondary side.

(2) It now appears that refueling on Unit 2 and Unit 1 will be coincident.

(3) The reactor protection system on Unit 2 will have a calculating module.

(4) During the problem with the surveillance holder tube, all of the fuel had to be removed to remove the pieces of the surveillance holder tube. A total of 609 poinds of original weight (all but two pounds of the surveillance holder tube components) were retrieved.

(5) A total of 91 operating days have been lost, a total overall capacity factor of 70%.

(6) One ratchet trip has occured since the last meeting of the User's Group. This was apparently a fault in the transfer switch.

(7) ANO has its own equipment for installing furmanite.

(8) John reported a problem of Asian clams clogging the condenser. The screens won't take out the larva. Clorine must be used during a very narrow time window in order to destroy the larva.

(9) The computer was changed out during the last refueling. B&W was very helpful. AP&L is very happy with the computer supplied by Systems Engineering Laboratory.

(10) Mr. Anderson is pleased with the sodium recorders which he is using.

(11) John reported a bonnet-to-body leak in the Velan shutoff valve immediately ahead of the spray valve.

(12) ANO-1 is operating with approximately 33% efficiency with the leaks in the cóndenser being the biggest efficiency loss usually.

(13) A reactor building cooling fan is out of service with a bearing failure (Joy axial flow fans).

(14) 3?? men are employed in operations including all security and custodial forces.

RANCHO SECO - SMUD

Mr. R. J. Rodriguez reported on operations at Rancho Seco as follows:

(1) Chronology of events:

January 1977 - Unit trip during instrument check (went out on high vibration on main turbine)

January 1977 - Main feedwater pump trip. This was apparently a governor problem.

January 1977 - 100% load rejection test without reactor trip

April 1977 - CRD stator problems

Spray valve malfunctions. Forty (40) hours required to fix bypass valve.

July 1977 - CRD transformer shorted to ground. CRD group #6 dropped causing crud burst.

(2) The Rancho Seco capacity factor has been 96% through the first 7 1/2 months of 1977.

(3) Rancho Seco has a program to shock the system with lithium hydroxide (LIOH) to prevent plate-out of crud on fuel assemblies.

(4) A total of 340 man rem of irradiation dosage was incurred during refueling.

(5) A total of 52 Veian valves in the 1" to 1 1/2" range were replaced with Carotest diaphragm valves during refueling.

(6) During OTSG inspection, iron oxide was noted in the lower tube sheet crevice.

(7) RC pump seals did not fit well during installation. Machining was required. One leaked and a chip was found between the seal rings. This was corrected, and the seals are now operating well.

(8) A tear-down of the Westinghouse turbine was accomplished during refueling - good and clean. Governor valve seat was broken and all were replaced. The generator was in good shape. Cracking was detected in the turning vanes in the piping. Baffles were lost in the MSR and 12% of the tubes in the reheater high pressure coil were plugged.

(9) A problem in drawing control was reported, particularly the updating of drawings to reflect changes. As a case in point, it was indicated that the drawings in the CRD Control Manual CRD System Manual do not agree with the drawings which were submitted for approval originally (B&W indicated that the manual drawings were correct).

(10) The problem of corrosion was reported on unprotected carbon steel pipes in the reactor building due to humidity.

(11) CRD group 6 was reported as being hard to latch due to chips caused by previous ratchet trips.

DAVIS-BESSE-1 - TOLEDO EDISON COMPANY

Mr. T. D. Murray, Superintendent of D-B reported on operations as follows:

(1) The following chronology of events was reported:

3/22/77 - All transmission lines out of service. One diesel also out of service. Fuel loading went very smoothly. Some problem with fuel handling equipment.

7/03/77 - Entered mode 4. Experienced some vibration problems with main feedwater pumps due to pipe loads on pump.

7/16/77 - Entered mode 3. Experienced problems with check valves in DH system sticking open.

8/12/77 - Initial criticality. Some problems were experienced with the reactimeter.

8/28/77 - Feed pump tripped due to surge capacitor failure.

9/14/77 - CRDM stator failure

9/24/77 - Electromatic relief valve stuck open. Ru..ure disc ruptured.

10/23/77 - SCRFS trip

10/28/77 - Impeller failure on main feed pump (DeLaval)

11/15/77 - Some problem with water hammer due to steam traps at 40% power.

(2) Mr. Murray announced that Mr. J. G. Evans, Chairman of the B&W User's Group, had been promoted to Assistant to Vice-President, Energy Supply.

The meeting adjourned shortly after noon on November 16, 1977. It was agreed by all that the meeting had been useful and beneficial.

ENCLOSURE 1

ATTENDEES

B&W USER'S GROUP MEETING

NOVEMBER 15, 1977

Name	Company
W. C. Bibb (Bill)	WPPSS
J. R. Holder (Joe)	WPPSS
O. S. Bradham (Ollie)	Duke
R. W. Montross (Bob)	Consumers
R. J. Rodriguez (Ron)	SMUD
T. D. Murray (Terry)	Toledo Edison
J. W. Junttila (John)	Ohio Edison
H. Ray Caldwell (Ray)	Ohio Edison
J. W. Anderson (John)	Arkansas Power & Light
G. R. Westafer	Florida Power
G. P. Beatty (Guy)	Florida Power
J. C. Perry (Jay)	Portland General Electric
G. P. Miller (Gary)	Metropolitan Edison - TMI
J. P. O'Hanlon (Jim)	Metropolitan Edison - TMI-I
A. M. Qualls (Allan)	TVA
P. F. Ahern (Paul)	PASNY
W. A. Cobb (Al)	B&W
J. P. Phinney (Jim)	B&W
W. H. Spangler (Bill)	B&W
C. W. Pryor (Charlie)	B&W
J. R. Smotrel (Jim)	B&W
A. W. Brown (Art)	B&W
R. E. Wascher (Bob)	B&W
E. S. Patterson (Pat)	B&W
L. R. Weissert (Lou)	B&W
F. R. Fahland (Frank)	B&W
R. J. Baker (Bob)	B&W

ENCLOSURE 2

AGENDA

B&W USERS GROUP MEETING
NOVEMBER 15 & 16, 1977
TWIN BRIDGES MARRIOTT MOTEL
WASHINGTON, D.C.

NOVEMBER 15, 1977

0800 - 0810	COFFEE	
0810 - 0820	OPENING REMARKS	W. A. COBB (AL)
0820 - 0915	OCONEE OTSG TUBE PROBLEM	C. W. PRYOR (CHARLIE)
0915 - 1015	REFUELING EXPERIENCE	J. D. PHINNEY (JIM)
1015 - 1030	COFFEE BREAK	
1030 - 1200	B&W BRIEFINGS (~20 MINUTES EACH)	
	(1) RC PUMP SEALS	W. H. SPANGLER (BILL)
	(2) NUCLEAR PARTS CENTER	L. R. WEISSERT (LOU)
	(3) INCORE DETECTORS	E. S. PATTERSON (PAT)
	(4) NI CALIBRATION	J. R. SMOTREL (JIM)
	(5) SITE PROBLEM REPORTS & FIELD CHANGES	R. E. WASCHER (BOB)
	(6) RATCHET TRIP	A. W. BROWN (ART)
	(7) ICS	R. W. WINKS (BOB)
1200 - 1300	LUNCH - IN-ROOM BUFFET SERVICE	
1300 - 1400	B&W BRIEFINGS (CONTINUED)	
1400 - 1630	SUPERINTENDENTS QUESTION PERIOD	

(1) OCONEE
(2) TMI
(3) CR #3
(4) ANO #1
(5) RANCHO SECO
(6) DAVIS-BESSE
(7) CONSUMERS
(8) TVA
(9) VEPCO
(10) WPPSS
(11) PGE
(12) PASNY
(13) OHIO EDISON

NOVEMBER 16, 1977

0800 - 0810	COFFEE	
0810 - 1100	PLANT EXPERIENCE REPORTS (~25 MINUTES EACH)	
	OCONEE	ANO #1
	TMI	RANCHO SECO
	CR #3	DAVIS-BESSE
1100 - 1200	USERS GROUP BUSINESS	

ENCLOSURE 3

NI CALIBRATION

I. NEED TO MAINTAIN NI CALIBRATION

II. CAUSES OF CHANGES TO NI CALIBRATION

III. PAST SEQUENCE OF EVENTS

IV. B&W RECOMMENDATIONS

V. CURRENT PROGRAM

I. NEED TO MAINTAIN NI CALIBRATION

A. Core power as derived from NI's feeds Reactor Protection System (RPS), therefore, NI calibration must be maintained so plant protection is not compromised.

B. Total flux signal uses in RPS:

RPS-I		RPS-II	
High Flux	- S,T	High Flux	- T
Flux/Imbalance/Flow	- S,T	Flux/Flow	- T
Flux Pump Monitor	- T	Low DNBR	- S,T
		Flux/Offset	- S
		Flux/Delta T	- T

T required for transient protection

S required for steady state protection

C. Safety Analysis assumptions

1. Tech Specs and FSAR are based on SA assumptions
2. Total NI calibration error of 4%FP to heat balance
   a. Normal calibration error limit = 2%FP
   b. Transient induced error = 2%FP

II. CAUSES OF CHANGE TO NI CALIBRATION

- NI detectors <u>infer</u> core power from core leakage flux

- Factors that affect core power to leakage flux relationship at NI detectors:

  1) Changes in neutron transport medium

     - Hydrogen density in downcomer (T_c changes)

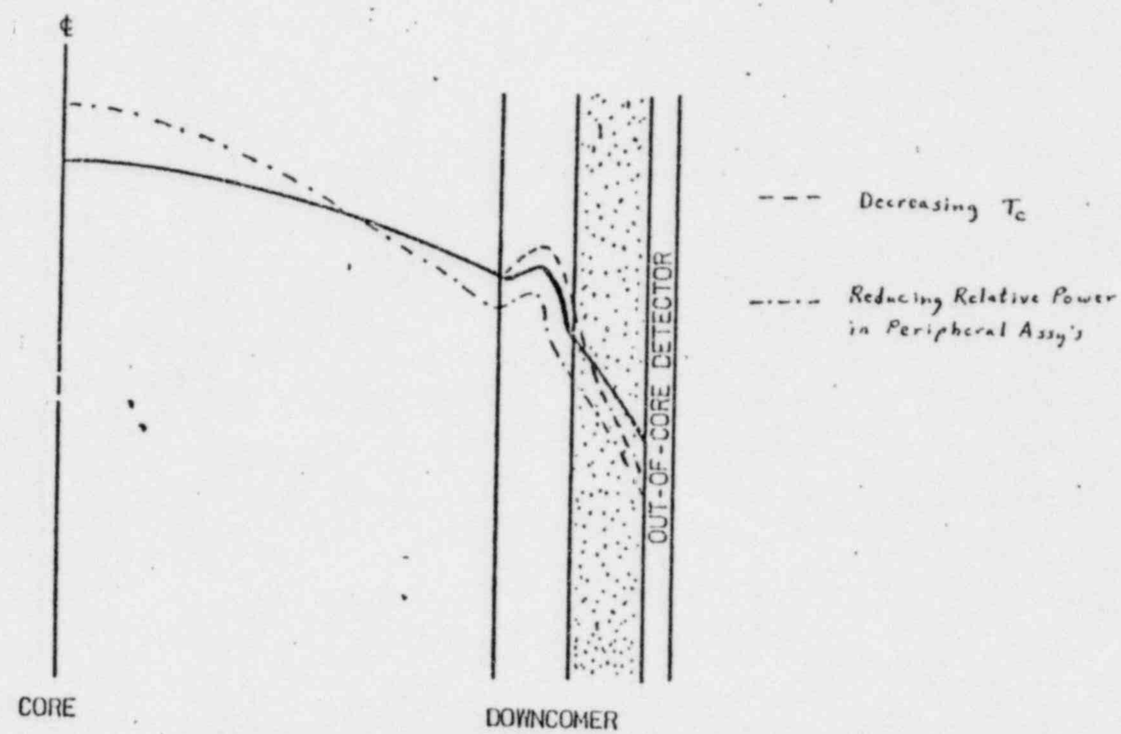
     - Boron concentration in downcomer

  2) Changes in radial flux profile

     - Rod movement

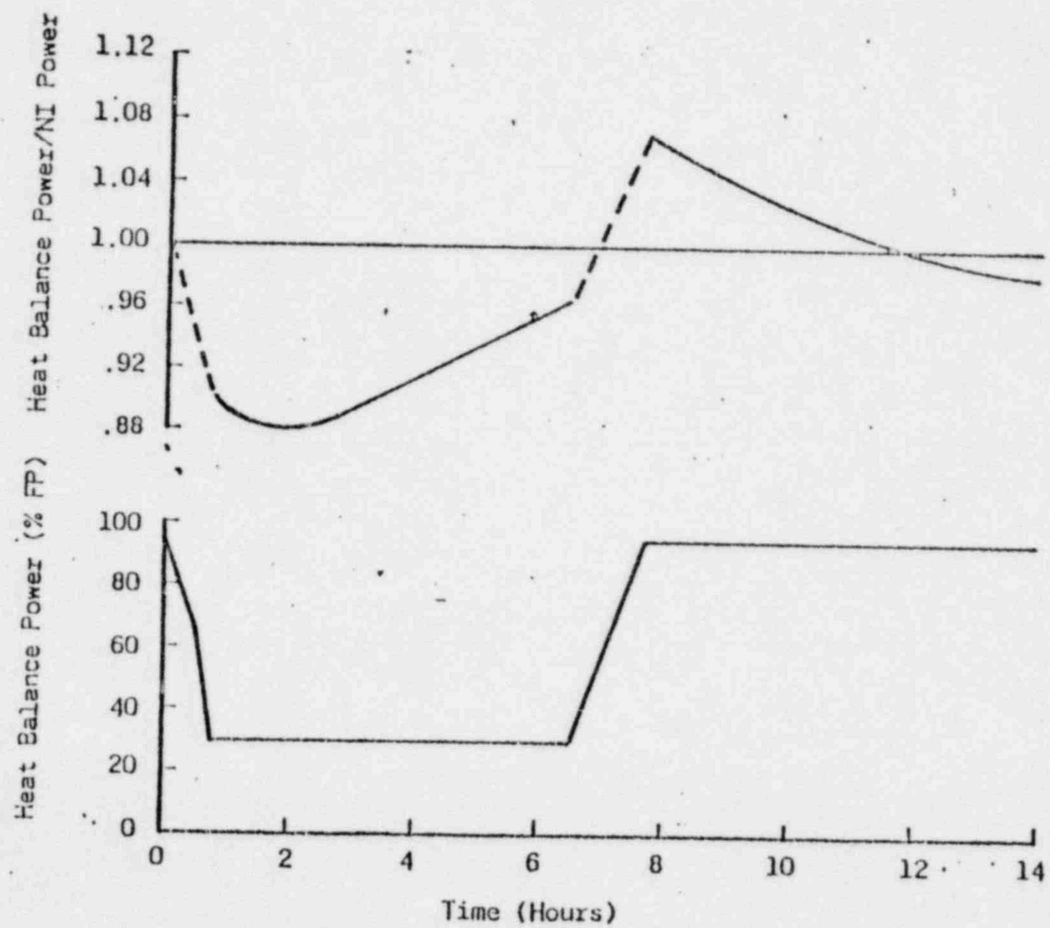
     - Xe distribution

     - Depletion (slow effect)



CHANGING OCD CALIBRATION

COMPARISON OF OCD POWER TO HEAD BALANCE POWER
(95-30-95 TRANSIENT TEST)



III. PAST SEQUENCE OF EVENTS

- August 1976 - Letter sent to 177 FA plant customers recommending more frequent NI calibration checks.

- March 1977 - Letter sent to 177FA plant customers reinforcing previous recommendations and providing more detailed surveillance suggestions.

- April 1977 - Information meeting held in Lynchburg with 177FA plant customers to discuss March letter and obtain customer feedback.

- May 1977 - Letter sent to 177FA plant customers containing proposed revision to B&W Standard Tech Specs on NI calibration for comment.

- October 1977 - Letter sent to 177FA plant customers containing recommended changes to Tech Specs and Operating Procedures.

Recommended Changes to Technical Specifications

1. NI power range calibration to heat balance should be checked a minimum of once per shift.

2. A re-calibration is required whenever a calibration check shows that the heat balance power exceeds the NI indicated power by 2%RTP or more.

   [Note: The safety analyses for this plant was performed assuming a maximum calibration error of 4%RTP (heat balance > NI indicated power) in the RPS setpoint.]

Recommended Changes To Operating Procedures

A. During Startups

1. Check NI power range calibration at power levels of approximately 15-30, 70, 90 and 100 percent of Rated Thermal Power (RTP).

2. A NI power range calibration should be performed if:

   a) Heat Balance(HB) minus NI indicated power $\left\{\begin{array}{l} > 2\% \text{ RTP} \\ < -10\% \text{ RTP} \end{array}\right.$ at 15-30, and 60% RTP calibration checks.

   b) HB minus NI indicated power $\left\{\begin{array}{l} > 2\% \text{ RTP} \\ < -2\% \text{ RTP} \end{array}\right.$ at 90 and 100% RTP calibration checks.

B. Steady State Operation (Power level maintained within 5%RTP band and no changes in rod index > 15% since last calibration check).

1. Check NI power range calibration once per shift and recalibrate, if necessary, in accordance with Tech. Spec. limits.

C. Power changes > 5% RTP and/or changes in Rod Index > 15% since last calibration check.

1. Check NI power range calibration after reaching desired power level and re-calibrate, if necessary, in accordance with Tech. Spec. limits.

2. In addition to first check, a minimum of two additional checks should be performed at 2 to 3 hour intervals to confirm that the calibration has stabilized, i.e. calibration is still within Tech. Spec. limits. This additional checking should continue until two consecutive checks show that further recalibration is not required.

D. NI Power Range Calibration Without the Computer

If the computer is not available for heat balance calculations, Tech. Spec. calibration limits should be adjusted in accordance with the accuracy of the hand heat balance calculational method used, i.e. a NI calibration should be performed if the calibration check shows

(Hand Calc. HB minus NI indicated power) > (4%RTP minus HB Calc. Accuracy* [%RTP])

*A value less than 2%RTP cannot be used without prior NRC approval.

V. CURRENT PROGRAM

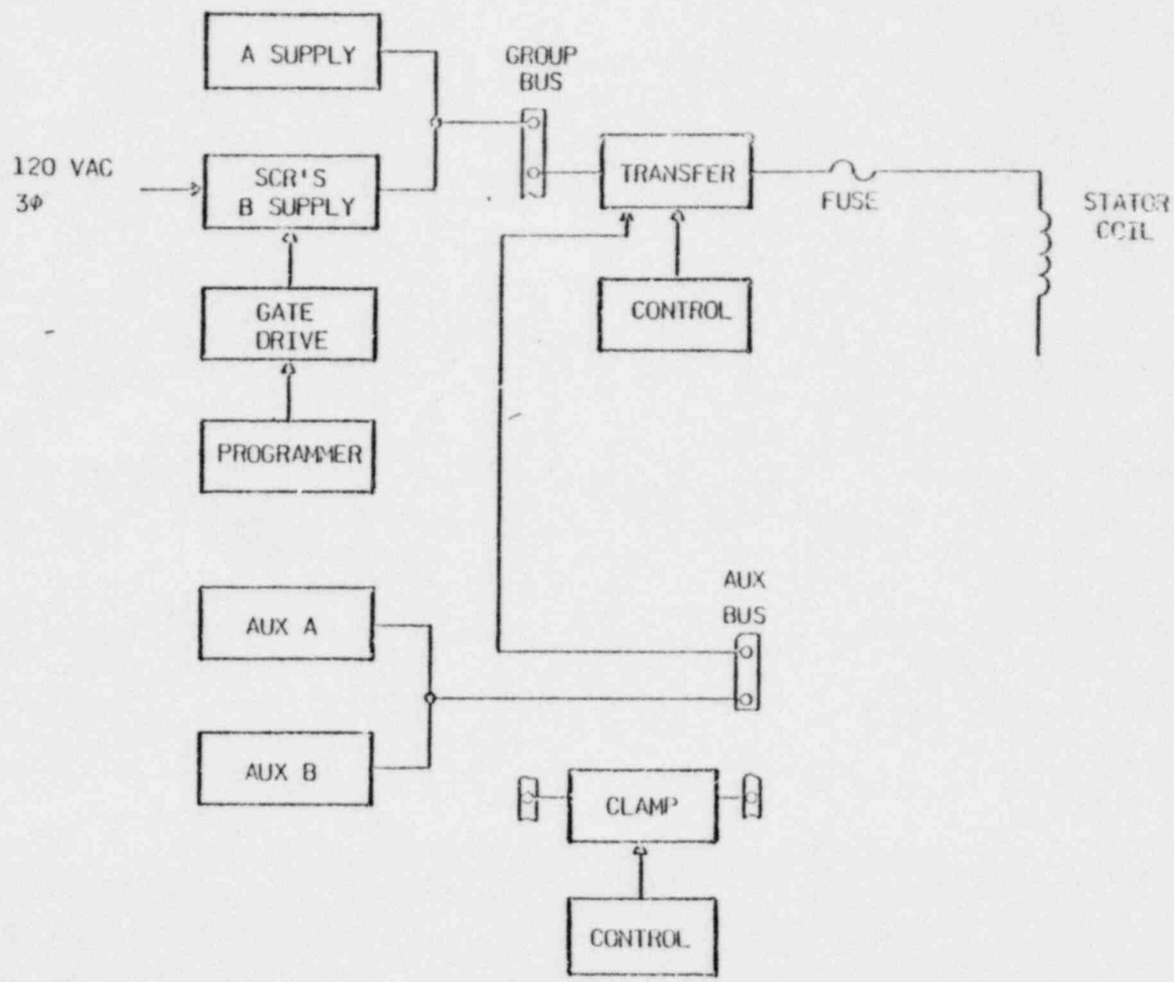
A. Calculational code is being developed to investigate the combined effects of power distribution and downcomer property changes on out-of-core detector response. Results will be used to determine magnitude of calibration problem on feed-and-bleed type plants.

B. Conceptual designs for auto calibrator (ΔT) and remote manual calibration devices have been developed for operating plants. Decision to continue work on these items will be based on the extent of problem following implementation of new Tech Specs and Operating Procedures.

ENCLOSURE 4

RATCHET
TRIP

THE CONDITION THAT OCCURS WHEN A CRDM STATOR IS MOMENTARILY DE-ENERGIZED AND QUICKLY RE-ENERGIZED AGAIN BEFORE THE CRDM LEADSCREW TRAVEL IS COMPLETE.


A SUPPLY
GROUP BUS
120 VAC 3Φ
SCR'S B SUPPLY
TRANSFER
FUSE
STATOR COIL
GATE DRIVE
CONTROL
PROGRAMMER
AUX A
AUX BUS
AUX B
CLAMP
CONTROL

RATCHET TRIP

PREVENTION PLAN OBJECTIVE

1. MINIMIZE THE POSSIBILITY OF FAILURES

2. MINIMIZE THE CONSEQUENCE WHEN FAILURES OCCUR

IF A STATOR PHASE FAILS TO BE ENERGIZED OR FAILS TO BE DE-ENERGIZED DURING ROD MOVEMENT, ROD WILL BE TRIPPED.

AREAS OF IMPROVEMENT

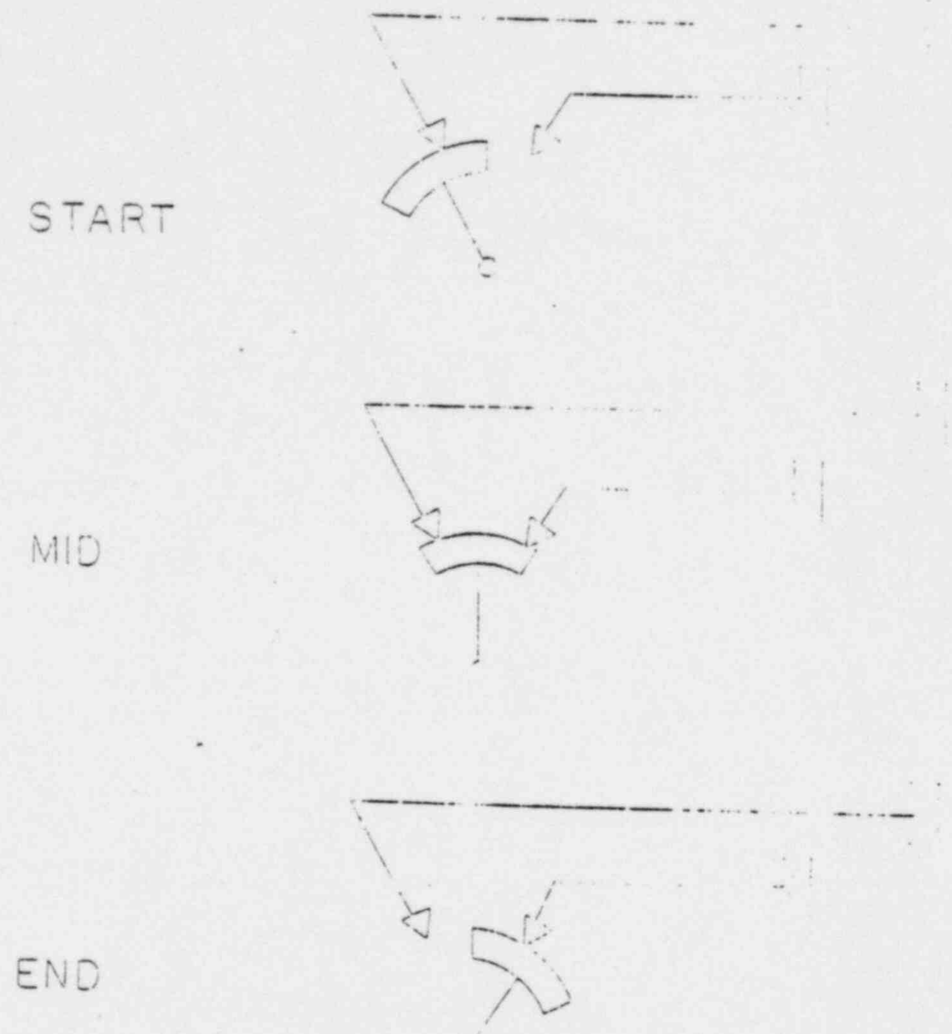
Improved Gate Drive Assembly

Transfer Switch Failure Detection

Power Supply Sequence Verification

Improved Transfer Switch

Improved Sequence Programmer



TRANSFER SWITCH ACTION

NEW COMPONENT

ANALYSIS AND TESTING

1. A MATHEMATICAL ANALYSIS OF THE DESIGN IS CONDUCTED USING WORST CASE CONDITION.
2. A LAB TEST IS CONDUCTED TO VERIFY THIS ANALYSIS.
3. A PROTOTYPE IS TESTED UNDER ACTUAL CONDITIONS IN THE CRDM ACCEPTANCE PROGRAM.
4. AN ACCELERATED LIFE TEST IS CONDUCTED.

ENCLOSURE 17

Operating Plant Service Bulletin

A Nuclear Services Publication Babcock & Wilcox

Volume 2 Number 39 September 30, 1977

cc: WTH
RT
BLW
done

OCONEE I

Thirty-three (33) tubes were explosively plugged in the B OTSG and one (1) lane tube stabilized. The B OTSG was successfully leak tested on 9/28/77. Fiberscope examination of a previously stabilized leaking tube was completed on 9/26/77 and revealed that the leak was an 1/8 inch round hole at the 14th tube support plate. The Safety Assessment Report was sent to NRC on 9/24/77. Power operation is now scheduled for 10/11/77.

OCONEE II

A stator failure produced a dropped rod on 9/23/77. A primary to secondary leak of approximately 0.2 gpm developed on 9/27/77. Because of this low leakage rate, it cannot be determined which OTSG is leaking. Power has been reduced to 70% to minimize secondary system contamination.

OCONEE III

The unit operated at 100% full power all week. The refueling shutdown will be delayed until 10/21/77 by load reduction to 50% full power on 10/1/77.

ANO-1

The reactor continues to operate at or near 100% full power with Plant Electrical Output at 94-95% due to both feedwater heaters being out of service.

TMI-1

Minor repairs to the RCP motors were completed and the unit restarted on 9/24/77. During escalation, a turbine trip was experienced from 40% full power due to electrical grounds in the turbine buss duct. The reactor was operated at 15% power while the buss duct was dried out, and unit was brought back on line 9/27/77. Unit returned to 100% full power operation on 9/28/77.

CRYSTAL RIVER III

Unit operated at 97% full power until September 27, 1977, when the unit was inadvertently tripped while performing a calibration check of the A-loop flow instrumentation. Unit was immediately returned to power and has operated at or near 100% full power the remainder of the week.

RANCHO SECO NO. 1

Fuel shuffle was completed on 9/24/77 and the plenum and closure head have been set in place. The containment ILRT is scheduled to begin this afternoon (9/30/77).

OTSG tube plugging operations were completed on 9/26/77. Eight tubes were stabilized at the upper end and explosively plugged on the lower end.

Current schedule calls for unit to be back on line 10/20/77.

DAVIS-BESSE I

A spurious closure of a feedwater valve caused the RCS pressure to increase and actuate the electromatic relief valve. A relay was missing from the valve controller and caused it to cycle several times and finally stick open. The stuck electromatic relief valve blew down continuously for approximately 20 minutes before it was isolated by closing its block valve. The RCS was subjected to a rapid depressurization.

Engineering and Service personnel are working closely with TECO to assess the causes and effects of the transient and to assist in the recovery, including discussions with the NRC.

ENCLOSURE 18

INFORMATION PROVIDED IN REPORTS
OF THE SEPTEMBER, 1977 DAVIS-BESSE EVENT
AVAILABLE TO GPUSC AND MET-ED

Source	Identification of Pressurizer Level Increase and Coincident Pressure Decrease	Description of Operator's Curtailing HPI Based on Pressurizer Level Increase	Interpretation of Significance of Pressurizer Level and Operator's Response
LER NP-32-77-16 (Enclosure 7)	Yes	No	No
Supplement to LER NP-32-77-16 (Enclosure 8)	Yes	Yes	No
NRC's LER PWR Listings (Enclosure 9)	No	No	No
NRC's Grey Book (Enclosures 10, 11)	No	No	No
NRC's "Current Events - Power Reactors" (Enclosure 12)	Yes	No	No
Atomic Energy Clearing House (Enclosure 13)	Yes	No	No
Nuclear Power Experience Newsletter (Enclosures 14, 15)	Yes	Yes	No
B&W User's Group Meeting (Enclosure 16)	No	No	No
B&W Operating Plant Service Bulletin (Enclosure 17)	No	No	No