TABLE OF CONTENTS

1228 002

7910300016

TABLE OF CONTENTS - Continued

1228 003

2.0 PLANT MODIFICATIONS

2.1 GENERAL

The plant design features related to safe operation have been described in detail in the TMI-1 FSAR and in various submittals to the NRC since the issuance of TMI-1's Operating License on April 19, 1974. Further modifications are being made to the plant in response to the staff's recommendations contained in the Commission's Order dated August 9, 1979. These modifications are described below and will be completed before startup of TMI-1 or shortly thereafter. Modifications to be completed before startup are described in Section 2.1.1 and modifications which may be completed later are described in 2.1.2. In addition Section 2.1.3 describes certain additional modifications not included in the staff's recommendations. These modifications were proposed by Met-Ed in its June 28, 1979 letter to NRC and are to be completed prior to restart of TMI-1.

2.1.1 Short-Term Modifications

2.1.1.1 Reactor Trip or Loss of Feedwater/Turbine Trip

2.1.1.1.1 System Description

A Safety Grade Reactor Trip System will be installed before restart in order to implement a reactor trip upon loss of both main feedwater pumps or upon a turbine trip. This system will derive four channel signals for loss of feedwater pumps and turbine trip. They will be used as inputs to the existing Reactor Protection System and will result in a trip of the reactor on coincident two of four signals.

2.1.1.1.2 Design Bases

The Safety Grade Reactor Trip System is designed to provide a reactor trip upon loss of main feedwater pumps or a turbine trip as an anticipatory trip. This would preclude reactor trips on high pressure for the anticipated transient conditions and minimize the challenges to the Pressurizer PORV and safety valves. The system will use redundant, four channel signals corresponding to those of the existing Reactor Protection System. It will be testable and meet the single failure criterion of IEEE-279.

2.1.1.1.3 System Design

A diagram of the system is shown in Figure 2.1-1. The turbine trip and feedwater pump trip signals will be derived from pressure switches on the control oil systems of the main turbine and the FW pump turbines respectively. Each of the four channel signals will be connected to the corresponding channel of the Reactor Protection System. The signals will be fed through contact isolators to preclude the propogation of faults into the Reactor Protection System (RPS). The reactor will be tripped through the existing RPS logic upon coincident signals from any two of the four channels.

A bypass arrangement will be provided in order to allow for power escalation, starting the main turbine and normal shutdown of the main turbine. The main turbine trip bypass will be automatically placed in effect when reactor power is less than 20%. The bypass will be automatically removed when the reactor power is increased above 20%. Bypass of the feedwater pump trip signal is automatically placed in effect when reactor power is less than 10%. It will be removed automatically when reactor power is raised above 10%. The bypass function will be accomplished individually in each of the four channels by means of bistables which monitor the power range nuclear instrumentation.

The additional modules required in the Reactor Protection System will be the same safety grade equipment type used in the original system. Wiring for redundant channels will be separated and run in Seismic I, safety grade raceways except in the turbine building. Since the turbine building is not Seismic I, the equipment and wiring therein cannot be classified as Seismic I. However, all wiring in the turbine building for this system will be run in conduit and redundant channels will be routed separately to minimize the probability of disabling more than one channel due to damage to the turbine building. The system will be designed with normally closed contacts so that an open wire will represent a tripped condition. The signals from the turbine building will go through contact isolat's in the Reactor Protection System to preclude the prop... n of faults in the system.

2.1.1.1.4 Design Evaluation

The Safety Grade Reactor Trip scheme provides an anticipatory trip to the reactor, reducing the number of reactor trips on high pressure and the number of challenges to the Pressurizer PORV and safety valves.

2.1.1.1.5 Safety Evaluation

The system is safety grade and meets the requirements of IEEE-279 including those for testability and single failure criterion. The modifications which will be required to the Reactor Protection System will not degrade the ability of that system to perform its design function. The design will result in an enhancement of nuclear safety.

2.1.1.1.6 Start-Up Testing

This system will be tested during installation to verify its operation prior to start-up.

1228 005

2.1.1.2 Position Indication for PORV and Safety Valves

2.1.1.2.1 System Description

The purpose of this modification is to provide the Control Room Operator with information on the status of the pressurizer electromatic relief valve RC-RV2 and the pressurizer code safety valves RC-RV1A and RC-RV1B. Discharge flow will be measured by differential pressure transmitters connected across elbow taps downstream of each of the valves. In addition, the electromatic relief valve will be monitored by accelerometers mounted on the valve. These will detect flow if the valve opens. Alarms and indications will be provided in the control room to inform the operator if any of these valves are open.

2.1.1.2.2 Design Bases

A reliable and unambiguous control grade indication will be provided to the Control Room Operator if the pressurizer electromatic relief valve or code safety valves open. The monitoring system will remain functional in containment conditions associated with any transient for which valve status is required by the operator. Redundant and diverse means will be provided for monitoring the electromatic relief valve (RC-RV2). The monitoring systems will remain functional during a loss of off-site power. All equipment inside containment will be seismically mounted. The integrity of existing safety related systems will not be impaired by this modification.

2.1.1.2.3 System Design

All of the system components have been selected for reliable operation and, where applicable for operation under adverse conditions inside containment. The differential pressure transmitter model which has been selected has previously been qualified for operation in a post-LOCA environment, for ability to operate after a seismic event and withstand 2.2×10^8 rads. The components comprising the acoustic flow detector have been previously used by B&W in the Loose Parts Monitoring System. They have been seismically tested and have been tested under the B&W "Steam Line Break" and "Small Break LOCA" containment environments. They will withstand 10^8 rads. The monitoring systems will be supplied from on-site electrical paver supplies. Diverse and redundant means will be used for monitoring of the electromatic relief valve. Both differential flow measurement and acoustic detectors will be provided.

2.1.1.2.4 Design Evaluation

Elbow taps are widely used for flow measurement in fluid systems and a great deal of empirical data is available for calculating expected differential pressure across elbow taps for given flow conditions. Calculations have been made, using conservative assumptions, to demonstrate that a satsfactory signal will be generated when any of the valves open. Calculations have been

1228 006

made for saturated, liquid and two phase flow. A summary of these calculations is provided in Appendix 2A. Tests run by B&W on the electromatic relief valve under reduced flow conditions have confirmed the validity of this approach. Because of the straight-forward and well known relationships that exist between flow conditions and differential pressure across the elbow, the signal from one differential pressure transmitter can be confidently predicted for any flow conditions. For this reason it has been concluded that operating tests, which would be difficult since they involve opening the PORV and relief valves, will not be required.

Acoustic monitoring of the electromatic relief valve makes use of well proven equipment and techniques which have been used in the B&W Loose Parts Monitoring System. Tests run on this valve at the B&W Alliance facility demonstrated that the acoustic monitoring system gave satisfactory results.

2.1.1.2.5 Safety Evaluation

Instrument taps will be installed on elbows in the discharge piping of pressurizer code safety valves RC-RV1A and RC-RV1B and electromatic relief valve RC-RV2. This piing is classified as N2, Seismic I. Analysis has been performed to demonstrate that this modification will not degrade the integrity of the existing pipe. The pipe classification has been maintained up to and including the instrument root valves. The mounting of new equipment which will be located in the vicinity of safety related systems has been analyzed to ensure that no hazardous missiles will be generated in a seismic event. It has been concluded that this modification will not degrade any safety related systems. The valve position indication function has not been classified as safety grade.

2.1.1.2.6 Instrumentation

The output signals from the three differential pressure transmitters will be displayed on indicators in the control room. They will be calibrated in "inches of water". Each signal will also go to an alarm bistable. A control room alarm will be initiated if any of the signals exceed a pre-determined value. This will alert the operator that one of the valves is open. The differential pressure signal will also be monitored by the plant computer for logging, trending, and alarm functions.

The outputs from the accelerometers which will be mounted on RC-RV2 will be processed by monitoring equipment installed in the existing Loose Parts Monitoring Cabinet. An output signal indicative of flow through the valve will be displayed and recorded locally. A control room alarm will be initiated if flow is detected. This signal will also be monitored by the plant computer for logging, trending, and alarm purposes.

1228 007

2.1.1.3 Emergency Power Supply Requirements for Pressurizer Heaters, PORV, Block Valve, and Pressurizer Level Indication

2.1.1.3.1 Pressurizer Heaters

2.1.1.3.1.1 System Description

The purpose of this modification is to provide redundant emergency power for the 126 KW of pressurizer heaters required to maintain natural circulation conditions in the event of a loss of offsite power. A manual transfer scheme will be installed to transfer the source of power for 126 KW of pressurizer heaters from the balance of plant (BOP) source to a "Red" engineered safeguards (ES) source. A similar manual transfer scheme will be installed to transfer the source of power for 126 KW of pressurizer heaters from the BOP source to a "Green" ES source. Each manual transfer scheme will have double isolation on each end of the transfer and have mechanical key interlocks to govern the order of the transfer procedure. Figure 2.1-4 is a schematic representation of these transfer schemes.

2.1.1.3.1.2 Design Basis

Babcock and Wilcox has recommended that at least 126 KW of pressurizer heaters be restored from an assured power source within two hours after a loss of offsite power. Separation and isolation of Class IE equipment and circuits from non-Class IE equipment and circuits will be in accordance with Regulatory Guide 1.75.

The 480 volt ES circuit breaker is the isolating device between Class IE and non-Class IE portions of the design. The Class IE portion of the design is that portion up to and including the 480 volt ES circuit breaker and protective elements. Undervoltage relays connected to the 480 volt ES bus will detect a fault that is of sufficient magnitude to endanger the ability of safety loads on the bus to start or run. The undervoltage relays will initiate tripping of the 480 volt ES circuit breaker feed to the pressurizer heaters and thereby remove any endangerment caused by that circuit.

While the remaining portion of the design is classified non-Class IE, separation will be maintained up to the pressurizer heater terminal box T-161 which is located on the secondary shield wall. The remaining portion of the design (i.e., terminal box T-161, pressurizer heater elements and interconnecting cable routing) will remain as it presently exists. The constraints imposed by the plant's original physical construction make this necessary. The relative closeness of the pressurizer heater elements and heater bundles does not permit further physical separation.

1228 008

The pressurizer heaters are passive devices. The only common event to affect both redundant emergency pressurizer heater circuits could only occur in that area between terminal box T-161 and the pressurizer heater elements. For such an event, the protection on the 480 volt ES feed to the pressurizer heaters will be fully coordinated with the protection on the 480 volt ES b.s main circuit breaker.

If both ..ergency circuits to the pressurizer heater are lost, reacto coolant pressure shall be sufficiently maintained through use of the make-up (HPI) pumps.

The double isolation in the form of the circuit breakers and removable elements (see Figure 2.1-4) along with the kirk key interlocks, preclude lining up the system with a 480 volt ES bus connected to the BOP bus or lining up the system with the "Red" 480 volt ES bus connected to the "Green" 480 volt ES bus.

B&W determined the number of pressurizer heaters by taking into account the following:

1. The loss through the pressurizer insulation was calculated. The service areas of the insulation was determined and an average heat flux for the outside service area was assumed to be 80 BTU/hr ft^2. This calculated to a heat loss of approximately 96,000 BTU/hr.

2. The loss through the uninsulated pressurizer areas around the horizontal heater bundles was calcu'ated in the same manner as item 1 and resulted in an approximate heat loss of 50,000 BTU/hr.

3. B&W's experience has shown that the insulated heat losses acocunt for less than half of the total losses. Therefore, a factor of 2.5 was applied to the sum of the accounted losses.

Thus, the total calculated heat loss from the system is 365,000 BTU/hr or 107KW. Due to the grouping at the pressurizer heaters, one bank of pressurizer heaters consisting of 126KW was recommended.

The time for establishing the heaters is determined by the amount of heat losses from the pressurizer and the initial water level in the pressurizer. Figure 2.1-2 shows the expected response after establishing natural circulation with no heat input from the heaters. From the Figure, two hours is sufficient time, for the heaters to operate, to insure natural circulation at hot standby after a loss of offsite power.

1228 009

2.1.1.3.1.3 System Design

Existing spare Class IE 480 volt circuit breakers on the "Red" and "Green" ES systems will be utilized for the two transfer schemes. The removable element assemblies for each transfer scheme will consist of two cabinets and one tab-keyed, removable element. One cabinet will be located near and connected in series with the 480 V ES circuit breaker. The other cabinet will be located near and connected in series with the Pressurizer Heater Control Center circuit breaker. Class IE qualified power cable will connect the load sides of the disconnect switches as shown in Figure 2.1-4. Class IE qualified under-voltage relays will be installed on each ES bus. They will initiate tripping of the ES circuit breaker to the pressurizer heaters when the bus voltage drops below its set point. The set point will be chosen so that starters on the ES bus can pickup if energized and the voltage at the ES motors is not lower than their ratings allow. An Engineered Safeguards actuation signal shall trip but not lockout each ES circuit breaker to the pressurizer heaters. The remainder of the electrical power distribution system to the pressurizer heaters will remain as it presently exists.

2.1.1.3.1.4 System Operation

All pressurizer heaters will be powered from the BOP electrical power distribution system when offsite power is available. Upon a loss of offsite power, manual transfers will enable each of the onsite emergency diesel generators ("Red" and "Green") to provide power to 126 KW of pressurizer heaters when the diesel generators can accommodate that load. Procedures will call for tripping non-essential loads to accomplish this within the two-hour requirement. Mechanical key interlocks will dictate that the order of events in the transfer from BOP to ES power source will be as follows:

A. Opening the circuit breaker in the PHCC which will allow removal of key #1.

B. Key #1 will open the cabinet door of the disconnect switch located near the PHCC. The removable element will then be removed along with Key #2 and carried to the 480 V ES switchroom.

C. The removable element will be inserted into the appropriate cabinet. Key #2 will lock that cabinet door and allow removal of Key #3.

D. Key #3 will remove the inhibit feature from the 480V circuit breaker.

1228 010

E. The circuit breaker control switch will then be operated to close the ES circuit breaker feed to the transferred pressurizer heaters when it has been established that bus loading and emergency D/G loading permit doing so.

When offsite power is restored, the reverse procedure will be used to transfer back to the BOP source.

2.1.1.3.1.5 Safety Evaluation

The manual transfer scheme design provides double Class IE separation of the ES system from the BOP system - the ES circuit breaker and the removable element. Taking into account the single failure criteria, faults on the BOP system will, at most, cause the loss of one 480 volt ES system. The transfer scheme design also precludes the connection of the "Green" ES system to the "Red" ES system.

2.1.1.3.1.6 Inservice Testing Requirements

The emergency diesel generator loading procedure will be rewritten to incorporate this modification. Therefore, these transfer schemes will be tested when the emergency diesel generators are tested.

2.1.1.3.2 Power Operated Relief Valve (PORV)

The present plant design is such that emergency diesel generator power will be supplied to the PORV (RC-V2) upon loss of offsite power. The PORV is powered from the 250 VDC Distribution Panel IC which in turn is pwoered from the "Red" and "Yellow" ES batteries and ES Battery Chargers 1A, 1C, and 1E.

2.1.1.3.3 Block Valve

The present plant design is such that emergency diesel generator power will be supplied to the block valve (RC-V3) upon loss of offsite power. The block valve is powered from the 480 V Engineered Safeguard Valve Conrol Center 1C.

2.1.1.3.4 Pressurizer Level Instrumentation

The present plant design is such that emergency diesel generator power will be supplied to the pressurizer level instrumentation power supplies (RC-1-LT1, RC-1-LT2, RC-1-LT3) upon loss of offsite power. The pressurizer level instrumentation power supplies are part of the ICS, NNI System, and are powered from the 120 volt ICS, NNI Power Distribution Panel ATA. That panel is, in turn, powered from the 120 volt Vital Distribution Panel VBA.

1228 011

To provide further assurance that emergency feedwater can be delivered when required, the failure mode of control valves EF-V30 A/B is being changed. Currently these valves fail half open on loss of control power and fail "as-is" on loss of instrument air. The change consists of modification to the operator such that on loss of air, the valves will fail in the open position and remain in this position.

Control valves EF-V30 A/B are controlled by the Integrated Control System. The design of this sytem is described in chapter 7 of the TMI-1 FSAR. Upon loss of all reactor coolant pumps, and/or both feedwater pumps, the IC positions the control valves to maintain steam generator water level. If reactor coolant pumps are available, the ICS controls are set to maintain a 30 inch water level on the start-up range level indicator. If reactor coolant pumps are not available, the ICS maintains steam generator water level a 50% on the operating range level indicator.

The Integrated Control System is a control grade system. It does, however, receive power from the Class 1E power system. Specifically the ICS is supplied from Distribution Panel ATA. This panel can be powered from the station batteries through inverter 1A and Panel VBA or from ES Control Center 1A through Panel TRA.

Manual Control of the emergency feedwater control valves can be taken from the control room. When manual control is selected all active components of the ICS are bypassed except for the raise/lower voltage circuit. As further assurance that control of the emergency feedwater control valves are available to the operator, an additional manual control station is being provided for each valve. The controls will be located in the control room and will be totally separate from the ICS. Power from the redundant portion of Class 1E power system will be provided to the back-up controls. Manual controls of the emergency feedwater control valves can be taken from the control room. When manual control is selected all active components of the ICS are bypassed except for the raise/lower voltage circuit. As further assurance that control of the emergency feedwater control valves are available to the operator, an additional manual control station is being provided for each valve. The controls will be located in the control room and will be totally separate from the ICS. Power from the redundant portion of Class IE power system will be provided to the back-up controls. A functional diagram of the new manual controls is shown in Figure 2.1-3. A new manual loader station for each control valve will be mounted on the control board. This will allow the operator to manually set a $\pm$ 10 volt control signal into the voltage/pneumatic converter in order to control the position of the EFW control valve. An adjacent selector switch connects the signal from the manual loader station to the voltage/pneumatic connector and disconnects from the ICS "EL" power supply to an independent 115 volt, 60 hz supply. Thus, if the EFW controls are disabled due to a failure in the ICS or failure of the "EL" power supply, the operator will have the ability to control flow to either steam generator entirely independent of the ICS.

1228 012

Each of the emergency feedwater supply lines has also been provided with a flow sensing device. This device is a sonic flow device as manufactured by Controltron and will be installed downstream of the control valves before the the lines enter the containment building. The flow device is safety grade and has been seismically qualified. The output of the flow devices will transmit the signal to the main control room where meters will be installed to read flow directly. The equipment to be installed will be safety related. Cabling will be routed as described in Section 7 of the TMI-1 FSAR. The power supply for the instruments will be derived from the vital 120 V power system. Redundant Power supplies will be used.

A diverse means of monitoring emergency feedwater flow is provided by the steam generator level indicators. These measurements are derived from Barley type "BY" transmitters which, subsequent to their installation at TMI-1, have been seismically qualified and qualified for operation in a post-LOCA containment environment. One start-up range and one operating range transmitter have been raised higher above the reactor building floor to avoid flooding in a post-accident situation and have had their electrical connections protected to prevent degradation due to moisture. The level instruments are supplied from 1E on-site power sources and their wiring is run in raceways which have been analyzed to assume heat. they will withstand a seismic event.

2.1.1.7.4 System Operation

The TMI-1 Auxiliary Feedwater System is a stand-by plant system which is not used during normal plant start-ups, shutdowns or operation. The system is maintained in stand-by during plant operations and is automatically actuated upon loss of both main feedwater pumps or loss of all four RC pumps. The following table gives actuation time for the system:

Event	Turbine-Driven	Motor-Driven
a) Loss of Feedwater or Loss of RC Pumps	Immediate	5 Sec.
b) Above with loss of off-site power (LOP)	10 Sec	
c) Above with ESAS but no LOP	15 Sec	20 Sec
d) Above with ESAS and LOP	25 Sec	30 Sec

Start-up and test data indicates that the turbine driven pump requires 18 seconds to reach full flow. The motor-driven pumps should be capable of accelerating to full speed in less than 10 seconds. Therefore under worst case conditions emergency feedwater flow should be established within approximately 40 seconds.

Control of auxiliary feedwater following initiation is accomplished by the ICS. The ICS controls the injection of auxiliary feedwater to maintain water level in each steam generator to one of two setpoints depending on whether RC pumps are or are not

1228 013

available. Under forced cooling conditions, the ICS controls level to 30 inches on the start-up range since this is sufficient to provide core cooling. However upon loss of forced RCS cooling the ICS controls steam generator level to 50% on the operating range to promote natural circulation with the Reactor Coolant System.

Manual controls in the control room are available for the operator to take control when needed or in the event of ICS failure.

2.1.1.7.5 Design Evaluations

Table 8-1 of the TMI-1 FSAR indicates that the heaviest loading on one diesel generator would result in 2513 KW or 97% of continuous rating of 2600 KW. The addition of the motor-driven emergency feedwater pump will add 450 H.P to the diesel laoding or 365 KW. This will result in a total loading of 2878 KW or 96% of the diesel's 2,000 hr rating of 3,000 KW. Since no credit has been taken for the reduction in pumping requirements following a LOCA and since the diesels 2,000 hr rating is not exceeded, the diesel operability will not be affected. A detailed loading study has also verified this fact and testing will be performed to further verify this fact.

2.1.1.7.6 Safety Evaluation

Safety analyses performed on the 177 Fuel Assembly B&W plants have determined that the emergency feedwater systems for a 2772 Mw plant must be capable of delivering 550 gpm (total to both generators). The basis for this criteria is contained in Volume 1; Section 6 - Supplement 3 of B&W's report entitled, "Evaluation of Transient Behavior and Small Reactor Coolant System Breaks in the 177 Fuel Assembly Plant". The analysis submitted by B&W is applicable to TMI-1. Several studies have also been performed by B&W for the 177 FA plants on loss of main feedwater transients. These analysis have demonstrated that 500 gpm or lower auxiliary feedwater flow is adequate following upset transients such as loss of power and the loss of normal feedwater flow. Therefore, the small break LOCA conditions with a 20 minute delay in auxiliary feedwater initiation sets the minimum emergency feedwater capacity requirements. Considering that TMI-1 is only a 2535 Mw, a minimum emergency feedwater capacity requirement of 550 gpm is very conservative.

As discussed in paragraph 2.1.1.7.3 above, the TMI-1 emergency feedwater system is comprised of two 460 gpm capacity electric pumps and one 920 gpm capacity steam driven (turbine) pump. The addition of the motor driven pumps (automatically) to the diesel block loading sequence and the turbine-driven pump start circuit ensures that a single failure will not result in less than the minimum required pump capacity being available under all conditions including loss-of-off site power. That is at least two motor driven or one motor driven and the turbine pump will be available under all single failure conditions.

1228 014

The addition of the motor driven auto-start circuits and addition of these motors to the diesel block loading sequence ensures that a single failure will not result in less than the minimum required pump capacity being available under all conditions including loss-of-off site power.

The TMI-1 AFW design provides a emergency feed line with control provisions in the line to each steam generator. The design is such that the required quantity of water can be provided to at least one steam generator during all single failure conditions involving a Loss of Coolant Accident or loss of normal feed. Under steam line or feed line break conditions, when both main and auxiliary feedwater is isolated to the affected steam generator, a single failure of the unaffected auxiliary feed line control valve will produce unacceptable results. To counteract this situation several short term design improvements have been implemented. A Back-up instrument air systems have been added, the failure mode of the control valves have been changed, and an additional manual control station has been added. All of these changes provide additional assurance that the TMI-1 control valves will be operable when required or at least will fail in the open position. In the long term, the system will be redesigned to account for the extremely unlikely condition where a control valve sticks closed during a steam or feedline break accident.

As noted above, the failure mode of the feedwater control valves, EF-V30A/B, have been changed from a fail-as-is to a fail open position on loss of instrument air. This failure mode is considered best because it gives priority to reliability of feedwater delivery for decay heat removal. Prevention of overfill is a second priority and a condition which should be prevented but without compromising decay heat removal.

Several changes have been made to ensure that the operator can prevent an overfill and overcooling condition. These changes consist of addition of the back-up class IE powered manual control stations for EF-V30A and EF-V30B in the control room. These changes were made to back-up the existing automatic level control system and plant instrumentation systems which in themselves are highly reliable. In addition, plant procedures are being modified to provide guidance to the operator in recognizing overcooling incidents and taking prompt corrective action. The operators will be trained in the requirements of these procedures as part of the Operator Accelerated Retraining Program. These changes ensure that control of the emergency feedwater system will be available to the operator in the control room for prevention of steam generator overfilling conditions.

1228 015

In the event that emergency feedwater control from the control room were not possible, operator action to prevent AFW overfill is possible based on the following:

1. The Auxiliary Feedwater (AFW) System does not continuously operate as main feedwater does and, therefore, the opportunities for AFW overfill are reduced.

2. The automatic and manual controls provided are highly reliable and simple.

3. A large amount of redundancy is available in the instrument air system.

4. The AFW system is relatively simple so the opportunities for failure are few.

5. The AFW fill rate is slow and therefore ample time exists for operator action. Depending on many variables such as total flow capacity, generator pressure, prior power level, etc., 7 to 15 minutes will be available before the water reaches the elevation of the top shroud of the steam generator.

6. Evaluations performed by B&W for another 177-FA plant indicate that overcooling to the above levels will not result in any unacceptable consequences for the NSSS components.

7. The plant operating and emergency procedures will be modified to address the issue of steam generator overfill. These procedures will be written such that operation action in the time permitted will be assured and verified to be achievable.

As noted in the discussion above on System Design:

a) The TMI-1 design provides for the automatic initiation of auxiliary feedwater.

b) Subject to the limitations discussed above the design accounts for single failures.

c) The initiating signals are powered from Class 1E power systems.

d) The A.C. motor driven pumps and valves in the auxiliary feedwater system are included in the automatic actuation of the loads to the emergency buses.

1228 016

e) The automatic initiating signals and circuits are designed so that failure will not result in the loss of manual capability to initiate AFW from the control room.

f) Safety-grade indication of auxiliary feedwater flow to each steam generator is being provided in the control control room. This design is consistent with the existing system design (i.e. one indicator per line is provided).

g) The Flow instruments are to be powered from Class 1E power systems.

Manual capability to initiate the auxiliary feedwater system from the control room has been retained and is such that a single failure in the manual circuits will not result in the loss of system function. In addition provisions for testing of the initiating circuits, although not currently included in the design, will be provided. Control room annunciation for all auto start conditions will also be provided.

2.1.1.7.7 Startup Testing and Inservice Testing/Inspection Requirements

During the initial TMI-1 start-up testing, hot functional testing was performed to:

1. Verify the Integrated Control System (ICS) controls the OTSG to the minimum level set point of 30 inches during HFT heat-up.

2. Verify the ICS controls the emergency feedwater system and OTSG level for the following simulated conditions:

   a. Both main feedwater pumps tripped.

   b. AC hand power to the I lost.

   c. All four RC pumps tripped.

   d. All four RC pumps & both main F.W. pumps tripped.

3. Verify the auto start capability of the steam driven emergency feedwater pumps.

4. Verify operability of the Emergency Feedwater System to supply feedwater when OTSG pressure is 1015 psig.

These tests are documented in Test Procedure TP 600/11. Acceptable test results were obtained and therefore no need exists to re-perform the above tests. However prior to re-start of TMI-1 the following test will be conducted:

1. Functional tests shall be performed to verify the emergency feed pumps start on loss of feedwater or loss of four reactor coolant pumps.

1228 017

2. A functional test shall be performed to verify the operability of the diesel generators with the loading of the emergency feed pumps.

3. The failure positions for the emergency feedwater control valves shall be verified.

4. A functional test of the new manual control valve station and the auxiliary feedwater flow instrumentation will be performed at cold shutdown conditions.

5. Operability of the new back-up instrument air compressors will be demonstrated.

During the TMI-1 Startup and Test Program, tests of the Emergency Feedwater System were conducted to demonstrate the ability to supply feedwater when the steam generator pressure was 1015 psig. The specifics of the test including test results and acceptance criteria were documented in Test Procedure TP 600/11, Emergency Feed System and OTSG Level Control Test.

During a portion of the test, the emergency feedwater system was operated with the Reactor Coolant System in a hot condition at approximately 532°F at 2155 psig with no nuclear heat. The steam generator pressure was adjusted to 1020 psig and the operating main feedwater pump was tripped. The test results verified the turbine-driven emergency feedwater pump automatically started. Manual control of the emergency feedwater control valves, EF-V30A and B, was then taken and the falves were fully open to verify the pump flow capacity of 920 gpm.

The turbine-driven emergency feedwater pump was stopped, steam generator pressure reduced to 900 psig, a motor-driven emergency feedwater pump started, and water level lowered to 20 inches on the startup range. The control valves were then returned to the automatic Integrated Control System (ICS) mode and the ability of the ICS to control to the 30 inch low level control demonstrated. The control valves were returned to manual control and steam generator water level was increased to 40 inches on the startup range. The control valves were again placed under automatic control and ICS control on low level again demonstrated. Similar testing was performed to demonstrate that during a loss of all RC pumps the ICS would control level to the high level set poi·

1228 018

The above described sequence of testing verified the mechanical design adequacy of the TMI Unit #1 Emergency Feedwater System, verified the ability of the ICS to control water level, and demonstrated the ability of the operator to manually control the steam generator water level under real dynamic conditions. Since the mechanical design features, i.e. piping configuration, control valves, etc., remain unchanged as a result of the restart modifications it is not considered necessary to repeat these tests for TMI-1 restart. Autostart capability of the motor-driven pumps, the ability of the new control stations to regulate EF-V30 A/B and the functionality of the new flow indications system will be demonstrated under conditions which will not result in an additional thermal cycle on the steam generator auxiliary feedwater nozzles or steam generator tubes.

It is recognized that the proposed testing program does not demonstrate that the operator can prevent overcooling. However, whether overcooling will occur is highly dependent on the initial plant conditions (i.e. power level, power history, etc.) and the operator action taken. Therefore, a single test cannot demonstrate that overcooling will not occur and cannot adequately train the operators in manual emergency feedwater control.

It is for this reason and to avoid thermal cycling of the steam generators that the emergency feedwater tests will be conducted at cold shutdown conditions to demonstrate the ability of the new equipment to operate as designed. Operator training in manual emergency feedwater flow control will be covered in the operator accelerated retraining program.

2.1.1.7.8 Instrumentation

As discussed above auxiliary feedwater flow instrumentation is being provided in the design of TMI-1. Other instrumentation required for the safe control and operation of the TMI-1 AFW System, such as steam generator level instrumentation, is described in chapter 7 of the FSAR.

2.1.1.7.9 Reference Drawings

C-302-081 Rev IB-0
SS-201-186 Rev IA
SS-201-187 Rev IA
SS-201-168 Rev IA
SS-201-169 Rev IA
SS-208-203 Rev IA
SS-208-205 Rev IA
SS-209-031 Rev IA
SS-209-032 Rev IA
SS-209-108 Rev IA
SS-209-590 Rev IA
SS-208-591 Rev IA
SS-209-660 Rev IA
SS-209-661 Rev IA
SS-209-662 Rev IA
SS-209-663 Rev IA
SS-209-664 Rev IA
SS-209-665 Rev IA
SS-209-666 Rev IA
SS-209-667 Rev IA
SS-209-755 Rev IA
SS-209-756 Rev IA
B-308-564 Rev IA-0
E-304-274 Rev IA-0
E-304-275 Rev IA-0
E-304-276 Rev IA-0
E-304-277 Rev IB-1
B-201-043 Sheet 1 Rev IA
B-201-044 Sheet 1 Rev IA

1228 019

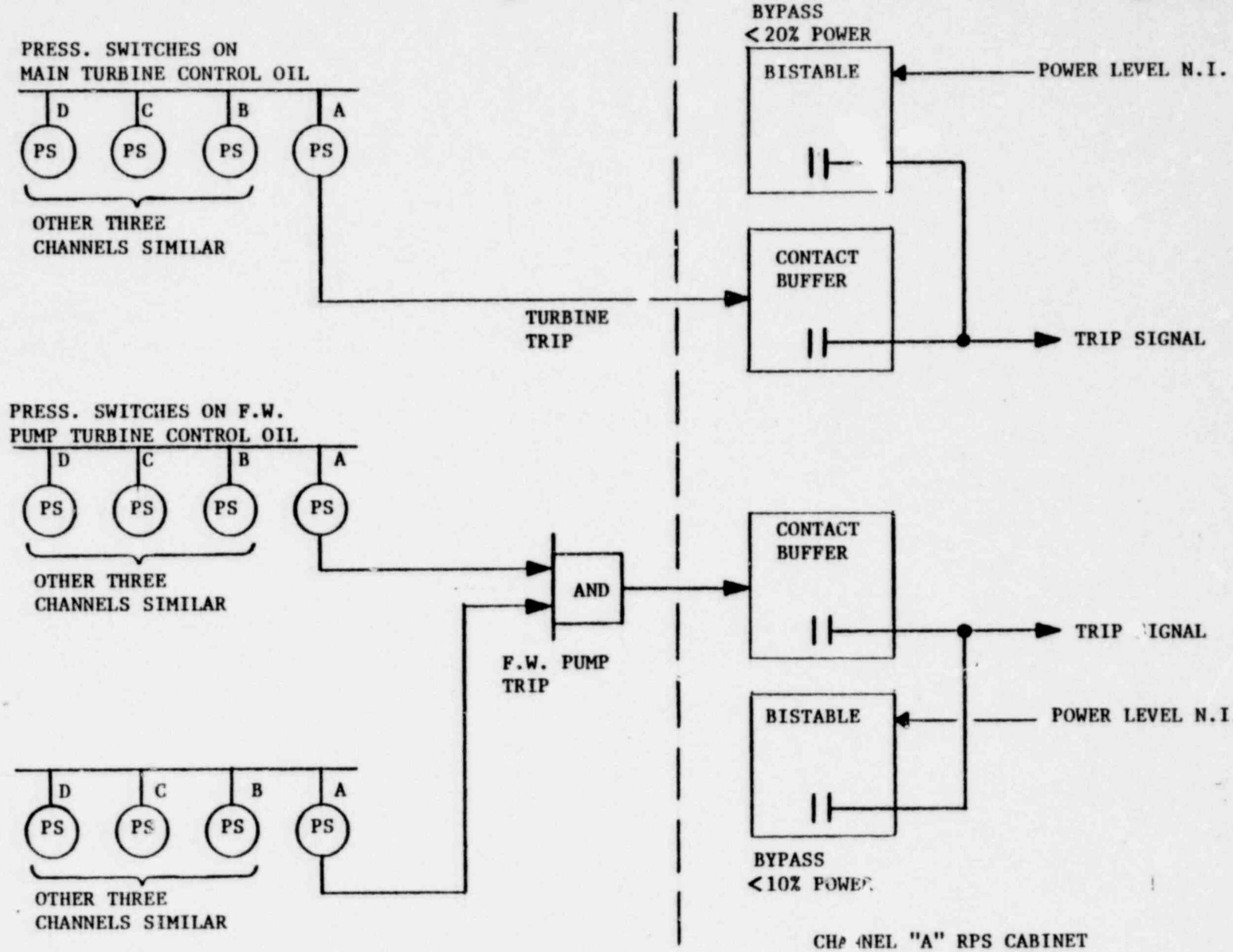


FIGURE 2.1-1
SAFETY GRADE REACTOR TRIP ON TURBINE TRIP OR F.W. PUMP TRIP

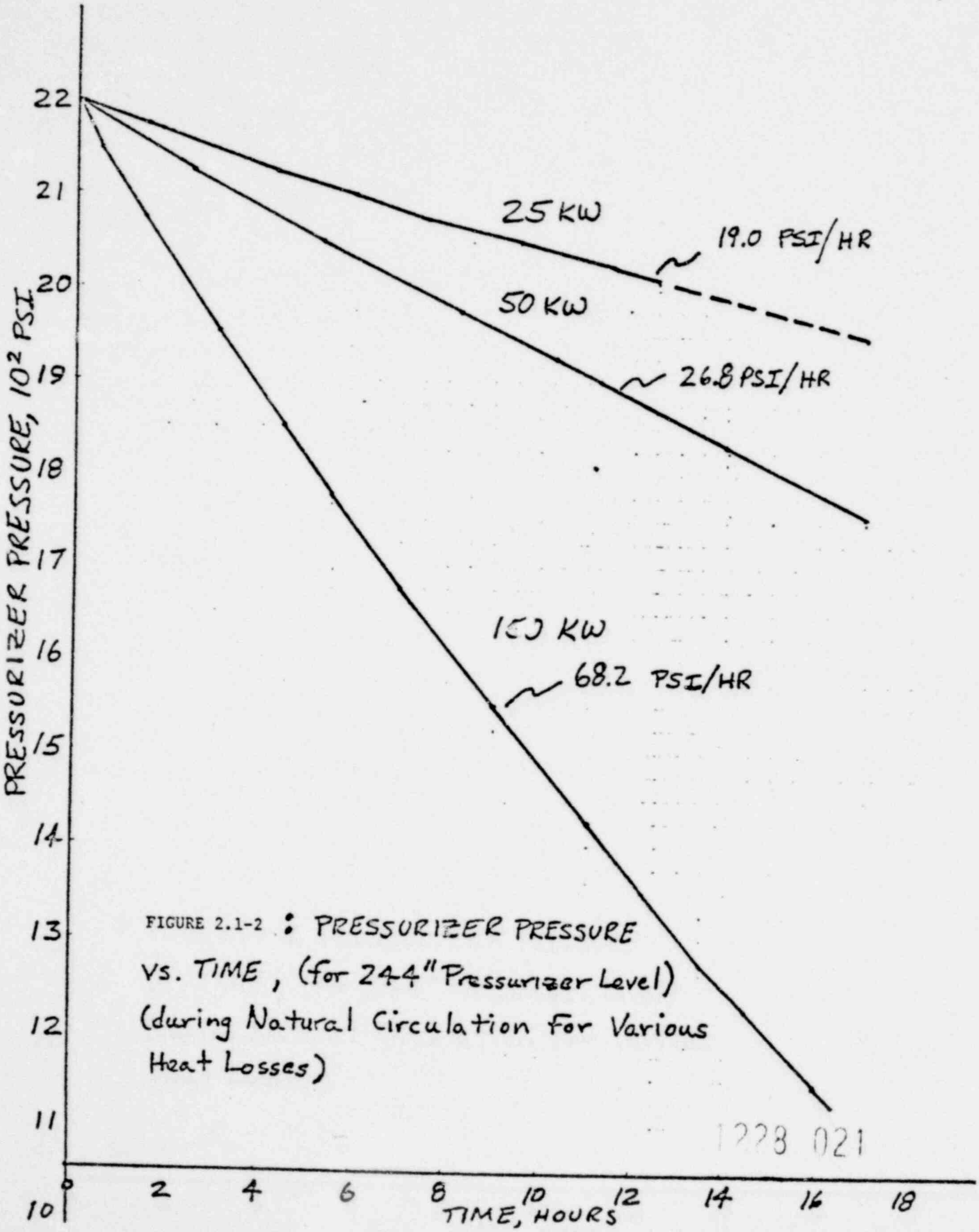
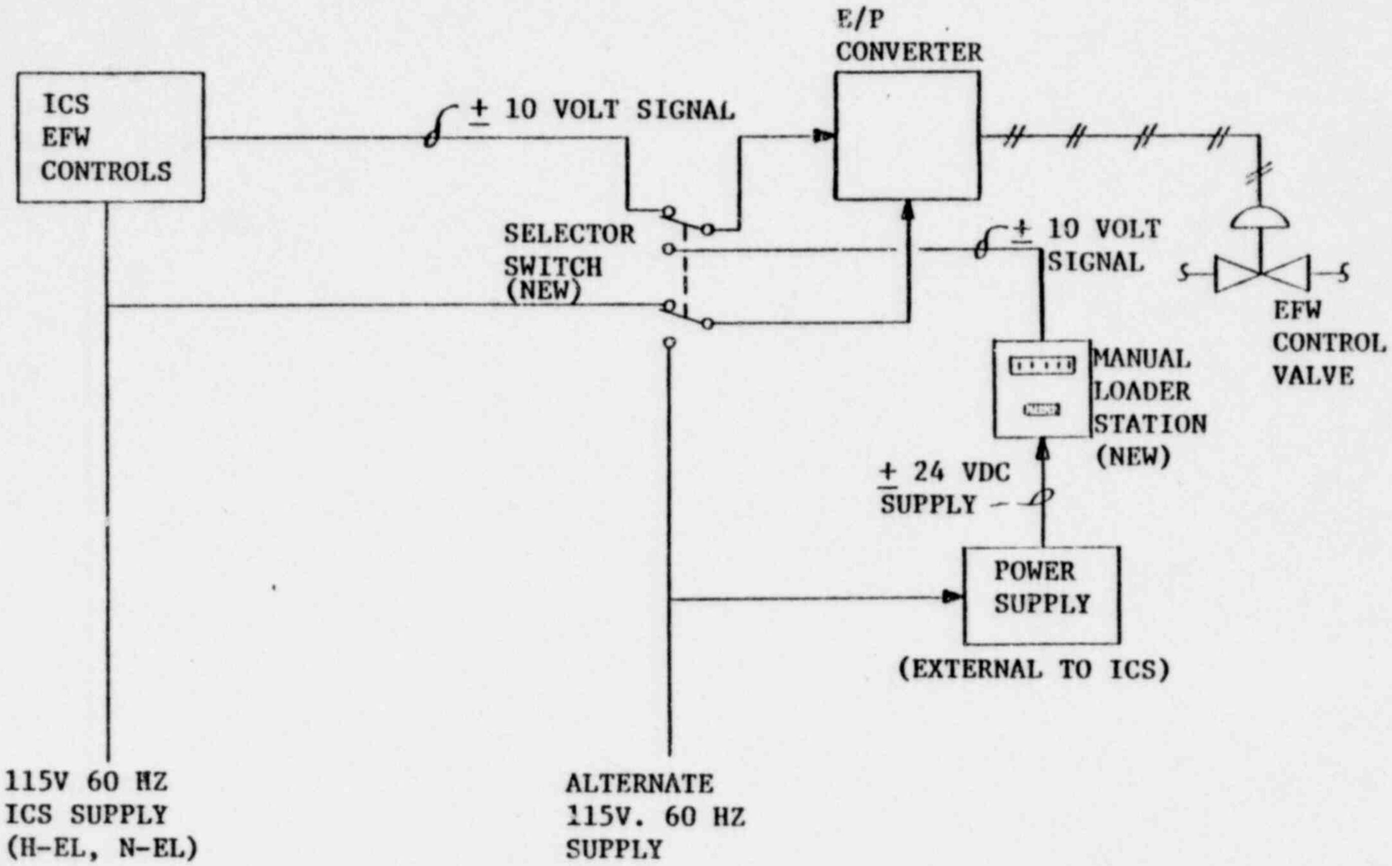


FIGURE 2.1-2 : PRESSURIZER PRESSURE VS. TIME, (for 244" Pressurizer Level) (during Natural Circulation for Various Heat Losses)

1228 021



MODIFICATION TO TMI-1 EFW CONTROLS
(TYPICAL FOR EACH STEAM GEN.)

FIGURE 2.1-3

DRAWN	CHK'D.	GPU Service
DESIGN LEADER	ENG.	
MANAGER APPROVAL		DWG. NO. / REV.
ENG. MECH		SCALE: / AUTH NO.

1228 022

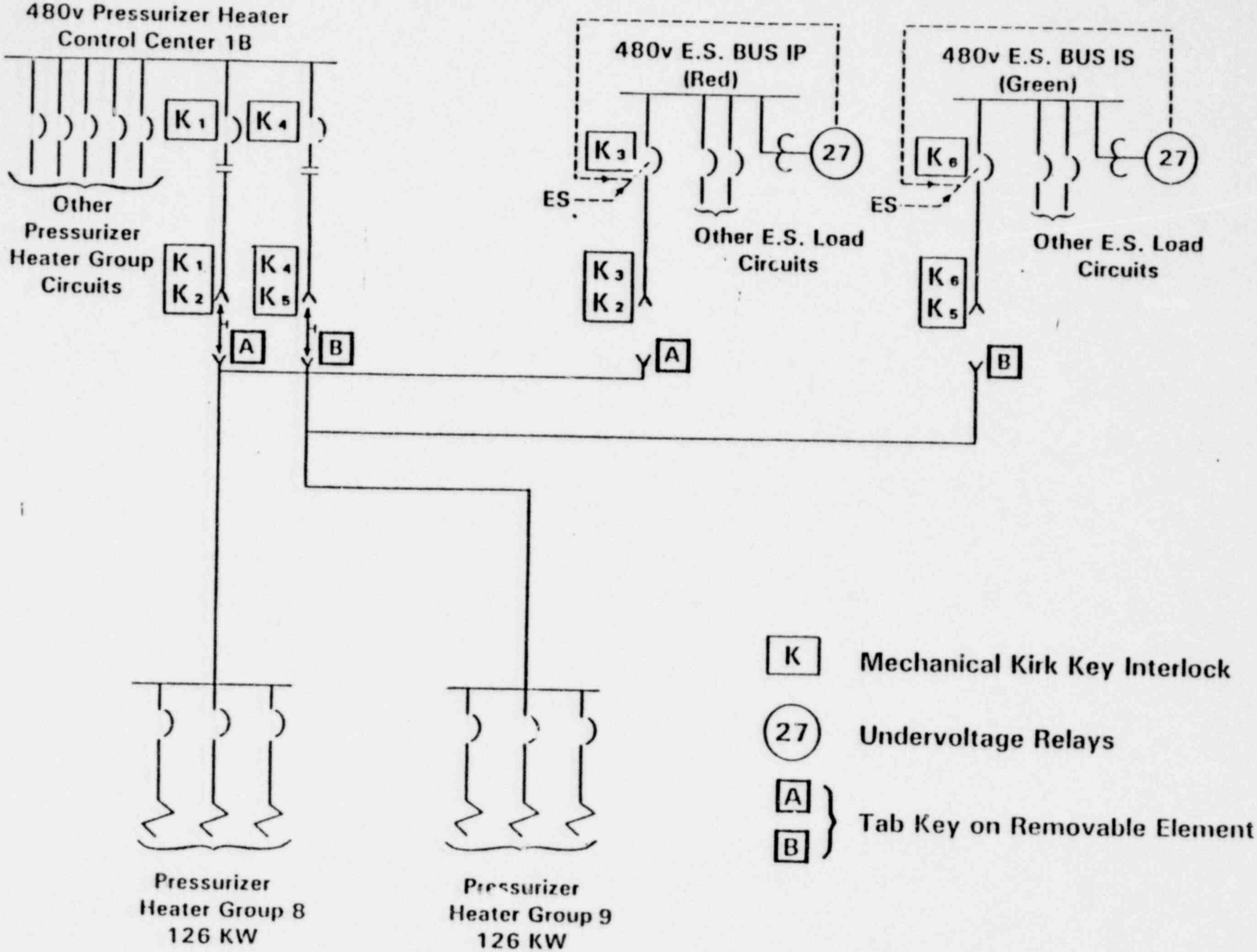


Figure 2.1-4

Am. 3

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APPENDIX 2A

To Be Submitted Later.

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shift and is cognizant of maintenance activities being performed while he is on duty. The Shift Supervisor has the authority and obligation to shut down the unit if, in his judgment, conditions warrant this action and is responsible for the station during emergency situations from the Control Room until relieved.

5.2.5 Shift Foreman

The Shift Foreman is responsible for the actual operation of the unit during his assigned shift. He reports directly to the Shift Supervisor. He directs the activities of the unit operators on his shift and is cognizant of all maintenance activities being performed while he is on duty. The Shift Foreman on duty has both authority and the obligation to shut down the unit if, in his judgment, conditions warrant this action.

5.2.6 Supervisor Preventative Maintenance

The Supervisor of Preventative Maintenance reports to the Unit Superintendent and is responsible for organizing and conducting preventative maintenance and surveillance for the Unit. Operation relted maintenance activities are coordinated with the Supervisor of Operations. Corrective maintenance for the station will be performed under the direction of the Director of Maintenance - GPU which is shown on Figure 1.2.

5.2.7 Director - Technical Support

The Director of Technical Support will report to the Vice President-Nuclear Operations and is responsible for the coordination of the technical engineering staff including the Nuclear Engineering, Mechanical Engineering, Electrical Engineering, Instrument and Control Engineering and Shift Technical Engineers.

5.2.8 Shift Technical Engineer

A Shift Technical Engineer is assigned to each operating shift (NUREG 0578-Section 2.2.1.b). This position reports to the Director-Technical Support. He is responsible for providing on shift engineering, technical and administrative support and advice to the Operations staff personnel. The Shift Engineer is in an advisory capacity and has no authority or control over the Shift Supervisor. He will provide direct technical oversight of the plant reactor performance and associated safety systems in order to improve the safety of unit operations and maintenance performance. A Shift Engineer is onsite at all times and can be in the Control Room within a few minutes.

The Shift Technical Engineer (NUREG 0579-Section 2.2.1.b) reports to the Director-Technical Support. He is responsible for providing on shift engineering, technical and administrative support to the Operations staff personnel. He will provide direct technical oversight of the plant reactor performance and associated safety systems in order to improve the safety of unit operations and maintenance performance.

5.2.9 Manager of Support Services and Logistics

The Manager of Support Services and Logistics reports to the Vice President - Nuclear Operations. In this position he is responsible for coordination of facility functions such as office management, facilities, personnel, station security and health physics and chemistry.

1228 025

Incumbent A

High School Graduate. Temple University - 2 Semesters. U.S. Navy 7/47 to 11/72. Retired. Rank: Lt.
Six years experience Nuclear Power Plant Maintenance - TMI.

Incumbent B

High School Graduate. Naval Course (Various) U.S. Navy 3/58 to 6/62. Rank: E5.
Westinghouse Electric Corp. Saxton, PA (Elec. Tech.) 7/66 to 11/68.
9 Years experience in Nuclear power Plant Operation and Maintenance - Saxton Nuclear Experi. Station and TMI.

5.4.7 Director - Technical Support

The Director-Technical support shall have 8 years in responsible positions related to power generation, of which one years shall be nuclear power plant experience. A Bachelor of Science Degree in an Engineering or Scientific field is preferred and may be credited to the remaining 7 years of experience. The individual should have non-desctructive testing familiarity, craft knowledge, and an understanding of electrical, pressure vessel and piping codes.

Incumbent

B.S. Mech. Eng. - Villanova University, 1963

1963	-	Cadet Eng. - Reading
1965-67	-	2 years Crawford Station - Plant Eng. and then Mech. Maintenance Form.
1967	-	1 1/4 year Saxton Nuclear - obtained NRC operator license
	-	8 years TMI Unit #1 - Supervisor Operations - 8/1/68 Plant Engineer - 1/1/73 Unit Supt. - 8/1/74 to May 77 Obtained SRO license.

5.4.8 Shift Technical Engineer

The Shift Technical Engineer shall have a Bachelor of Science Degree in an Engineering or Scientific related field. A minimum of two years of related experience in power generation. In addition to the academic education, the Shift Engineer shall possess a thorough knowledge of plant systems and components. In addition, it is intended that the Shift Engineer obtain the training necessary to be licensed as an SRO on an as soon as practicable basis.

Incumbent A

High School Graduate. University of Missouri - B.S. Mechanical Engineering - 1972

1228 026

8.0 SAFETY ANALYSIS

8.1 INTRODUCTION

Changes affecting the acceptance criteria for the TMI-1 FSAR safety analyses arise from several sources. First is the TMI-1 "Order and Notice of Hearing" (Reference 19) which contains NRC staff recommendations that certain changes be made to the plant. This order encompasses recommendations made in NRC bulletins 79-05 A, B and C and the TMI-2 Lessons Learned Task Force NUREG-0578 (Reference 20). Most of the changes listed below are being made in response to this order. Prior to the TMI-2 accident, B&W 177 FA plants received orders requiring modifications to the high pressure injection system to accommodate certain small break LOCA's. These changes are being evaluated as well. A third source of changes has originated from plant upgrades that Metropolitan Edison believes would improve plant performance. Some of these modifications were being evaluated prior to the TMI-2 accident on March 28, 1979. Certain analyses have been, or will be, performed using the TMI-1 RETRAN computer model to model the modified design to plant relevant transients. These analyses will be selected in light of insight gained from TMI-2. The analyses of interest are:

1. The transition to natural circulation following loss of offsite power.

2. The feedline break accident with regard to functional requirements for the emergency feedwater system.

3. Partial and complete loss of feedwater events and their sensitivity to: PORV setpoint, emergency feedwater flow, and reactor trip on loss of feedwater/turbine trip. TMI-1 has design features which permit a turbine trip without causing a reactor trip. Since the reactor will now be tripped by a turbine trip, the following questions will be addressed in this safety analysis: 1) Should these features remain in the plant or be deleted; and, 2) what is the effect of the retention/deletion on the revised plant design? A second area of investigation was the PORV setpoint. As indicated in Reference 2, B&W analyses indicated that a setpoint of 2450 psig would prevent lifting of this valve for all transients that have been experienced at B&W plants. Finally, RETRAN analyses will also be used to determine if overcooling can occur as a result of EFW operation following a loss of offsite power. The present design would allow 200% capacity if all three pumps operate and the OTSG level would be controlled at 50% of the operate range.

   These analyses will also support design decisions affecting plant modifications. A final source of input will come from the Abnormal Transients Operating Guidelines (ATOG) Subcommittee of the B&W 177 FA Owner's Group. Met-Ed is a full participant in this group and will utilize results in developing operator guidelines, for TMI-1. The RETRAN model could be used in lieu of B&W analyses if plant specific analyses are required in developing operator guidelines.

The decision to investigate additional accidents/transients was arrived at by reviewing the events in Table 8.2-1. These events were developed from the TMI-1 FSAR, the Standard Format and Content Guide, Rev. 3, and NRC requests for additional information from the TMI-1 and TMI-2 dockets.

8.2 AREAS OF INVESTIGATION

The plant modifications which are being investigated are summarized below. They are grouped according to their origin.

8.2.1 Modifications Resulting from the August 9, 1979 Order

1. The reactor protection high pressure trip setpoint has been changed to 2300 psig from 2390 psig. This lower trip setpoint in conjunction with the higher power operated relief valve (PORV) setpoint of 2450 psig results in a lower likelihood of PORV operation.

2. A complete loss of feedwater flow will initiate a reactor trip.

3. A turbine trip will initiate a reactor trip.

4. The emergency feedwater system will be modified to allow:

   a. automatic initiation of the steam and motor drive EFW upon loss of all 4 reactor coolant pumps, feedwater/steam differential pressure and a loss of main feedwater.

   b. loading of EFW pumps on the diesel generators and deletion of the blackout start interlock.

   c. alternate manual control for the EFW system.

5. The emergency feedwater system will be modified to start automatically on the following safety grade signals:

   a. low steam generator level

   b. negative differential feed to steam differential pressure.

   c. loss of all four reactor coolant pumps. Since this item is long term, plant safety will be discussed with and without these changes.

8.2.2 Modification as Result of Order of May, 1978

Modifications to the high pressure injection system. The HPI injection lines have been cross connected to assure acceptable results from a break in a high pressure injection line. Cavitating venturis have been added to provide the proper flow split in the event of an HPI line break.

8.2.3 Modification Originating from within Met-Ed

1. Post accident instrument and valve operator availability will be improved by the addition of heat shrink tubing.

2. The switchover of the ECCS system suction supply from the borated water storage tank (BWST) will be accomplished automatically rather than by operator action.

3. The reactor building spray system will be modified to delete sodium thiosulfate. Sodium hydroxide will be retained. This change will provide equal drawdown of the BWST and NaOH tanks for a large spectrum of single failures.

4. The fuel handling building, which is presently shared between TMI-1 and 2, will have an airtight barrier partitioning the building.

8.2.4 I&E Bulletin 79-05C

Met-Ed is in the process of evaluating the response to this bulletin. It is expected that a reactor coolant pump trip will be initiated on a SFAS coincident with an indication of a large (in excess of 10-20%) void fraction. This or any other change will be evaluated with regard to their effect on the plant accident and transient analyses and plant operating guidelines.

8.3 EFFECT OF CHANGES ON SAFETY ANALYSIS

Following are summaries of the accidents listed in Table 8.2-1. Table 8.2-1 indicates where FSAR analyses took credit for non-safety grade equipment, or where mitigation is dependent on a specific operating/emergency procedure or design margin. These conclusions will continue to be revised to account for plant design changes.

The event description and mitigating equipment are for the plant design before modification. The modifications discussed in the previous secitons were considered in the review of each accident. If a modification affected that analysis, then a note as to its safety significance was made under the "conclusions" section.

8.3.1 Rod Withdrawal from Startup (FSAR Section 14.1.2.2)

1. Description

   Uncontrolled reactivity excursion starting from a subcritical condition of $1\%\Delta k/_k$ at hot standby.

2. Acceptance Criteria

   i. Limit power to design overpower (112%)

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ii. RCS pressure not to exceed code allowable of 2750 psig.

3. Mitigation

i. RPS trip on high pressure for fast power rises.

ii. Pressurizer code safety valves lift and peak pressure is limited to 2515 psia.

iii. Doppler coefficient provides a negative reactivity addition.

4. Conclusion

The FSAR analysis still bounds the modified TMI-1 plant design. The RCS high pressure trip is lower and safety margins are increased. Since no credit was taken for operation of the PORV, raising the valve setpoint does not change the analysis results. As discussed in Ref. 2, the PORV would lift for the worst case rod withdrawal accident which was analyzed in the FSAR. Nevertheless, the probability of occurrence has been decreased so that safety margins have been improved and lifting of the PORV is not likely for a broad spectrum of rod withdrawal accidents.

8.3.2 Rod Withdrawal at Power (FSAR Section 14.1.2.3)

1. Description

Accidental withdrawal of a control rod group at normal rated power, without ICS control and a 1% shutdown margin.

2. Acceptance Criteria

i. Limit power to design overpower of 112%.

ii. RCS pressure not to exceed code allowable (2750 psig).

3. Mitigation

i. RPS trips on high pressure for slow transients and high neutron flux for fast transients.

ii. Doppler and moderator coefficients provide negative reactivity addition.

4. Conclusions

The FSAR analysis bounds the modified TMI-1 plant design. Lowering of the reactor trip setpoint increases safety margins for this event. Credit was not taken for PORV operation. As discussed in Reference 2, some low worth rod

withdrawals can result in PORV actuation. Nevertheless, the probability of such an occurrence has been greatly decreased by the changes in the PORV and high pressure trip setpoints.

8.3.3 Moderator Dilution Accident (FSAR Section 14.1.2.4)

1. Description

Diluted makeup water is inadvertently added to the reactor coolant system at a rate of 500 gpm beginning at normal power. RCS boron concentration is at its highest initial value. The result is a reactivity insertion, increased power, pressure and temperature. The addition of one makeup tank volume of unborated water changes the shutdown margin by .8% $\Delta k/_k$.

2. Acceptance Criteria

i. Reactor power will be limited to less than the design overpower (112%).

ii. Reactor coolant system pressure will be limited to less than code allowable 2750 psig.

iii. The minimum shutdown margin will be at least 1% $\Delta k/_k$.

3. Mitigation

i. High pressure or high temperature trip.

ii. Termination of deborated water to makeup tank on reactor trip.

iii. Termination of makeup flow on high pressurizer level.

4. Conclusion

The FSAR analysis bounds the modified TMI-1 plant design. Lowering of the high pressure trip setpoint increases the safety margins for this accident. Operation of the PORV was not assumed in the original analysis, and peak pressure is 2435 psia. Therefore, the PORV setpoint will not be reached during this transient.

Reactor power is limited to 107.3%, and the final shutdown margin is greater than 1% $\Delta k/_k$ even with the most reactive rod stuck out of the core all of the acceptance criteria for this accident are met.

8.3.4 Cold Water Addition (FSAR Section 14.1.2.5)

1. Description

Startup of one or more idle reactor coolant pumps can cuase excess heat removal from the primary coolant system. This cooldown can cause positive reactivity insertions, which

result in a power rise. The worst case event is the startup of two reactor coolant pumps from 50% power. A tripped rod worth of 1% $\Delta k/_k$ is used in the analysis.

2. Acceptance Criteria

   i. Limit overpower to less than the maximum design overpower (112%).

3. Mitigation

   i. RPS trip on high pressure for slow power increases or power/flow mismatch for rapid power increases.

   ii. RC pump/power monitor limits initial conditions under which event can occur.

4. Conclusion

Lowering of reactor trip setpoint increases safety margins for this event. The FSAR analysis was performed without taking credit for PORV. Peak pressure did not exceed 2400 psia, hence the PORV will not lift during this event.

The FSAR analysis bounds the modified TMI-1 plant design.

8.3.5 Loss of Coolant Flow (FSAR Section 14.1.2.6)

1. Description

Fuel rods experience a limiting DNB transient when all four reactor coolant pumps trip on loss of offsite power or when one pump experiences a locked rotor resulting in an instantaneous loss of flow. The loss of flow analysis is performed from 114% normal power, nominal reactor coolant pump flow, a +2 F core inlet temperature error and a -65 psi error in pressure. Reactor trip delay is assumed to be 620 ms. and a 1% $\Delta k/_k$ subcritical margin is assumed at hot standby. The event is analyzed past the time that the minimum DNBR occurs.

The locked rotor accident is performed from an initial power level of 102% power, with a rampdown in flow from 100% to 75% in 100 ms. Temperature and pressure were the same as for the loss of flow accident. Reactor trip delay is assumed to be 650 ms.

2. Acceptance Criteria

   i. DNB is greater than 1.3 for a loss of coolant flow.

   ii. DNBR is greater than 1.0 for a locked rotor accident.

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3. Mitigation

i. Protection from four pump coastdown is by limitation of peaking factors, limitations on power level and the pump power monitor.

ii. Protection for the locked rotor accident is by the flux/flow monitor initiating reactor trip.

4. Conclusions

The FSAR analysis for the four pump coastdown terminates prior to establishing stable decay heat removal by natural circulation. The EFW system will automatically start and maintain steam generator level at 50% on the operate range. This design should result in the transition to stable conditions; a startup test will be perfromed to demonstrate this transition prior to startup.

8.3.6 Dropped Control Rod (FSAR Section 14.1.2.7)

1. Description

A dropped control rod reduces the average coolant temperature and reduces power. A return to full power may result in high local power density and heat fluxes. The analysis is performed at rated power with the most adverse values of the moderator and doppler coefficients (EOL) Rod worth are the maximum expected for full power operation with and without Xenon. Tripped rod worth is assumed to be 1% $\Delta k/_k$.

2. Acceptance Criteria

i. DNBR remains above 1.3.

ii. Reactor coolant system pressure is less than code allowable (2750 psig).

3. Mitigation

i. The integrated control system inhibits withdrawal of control rods and ramps secondary side steam demand to 60% rated power to prevent overcooling.

4. Conclusions

This analysis has not been changed as a result of any of any TMI-1 plant design changes. Analysis results still show that the acceptance criteria are met. It should be noted that while ICS action is assumed in this analysis, acceptable results are not dependent on ICS operation. The dropped control rod analysis performed in the TMI-2 FSAR does not assume ICS action, and demonstrates that the accident acceptance criteria are met.

8.3.7 Loss of Electric Power (FSAR Section 14.1.2.8)

1. Description

Separation of the unit from the transmission network can result in the trip of the turbine and reactor. As analyzed in the FSAR, a more severe transient occurs if the ICS does not run back the reactor load demand. The result is reactor trip on high pressure. Cooldown is accomplished through the atmospheric dump or steam relief valves. In the presence of failed fuel and primary to secondary leaks, this event can lead to low levels of radioactivity release.

2. Acceptance Criteria

i. DNBR shall not be less than 1.3.

ii. Reactor coolant system pressure will not exceed code allowable limits of 2750 psig.

3. Mitigation

i. Reactor trip on high pressure.

4. Conclusion

This transient has an increased safety margin over the analysis performed in the FSAR as a result of the high pressure trip setpoint reduction to 2300 psig and the anticipatory reactor trip with turbine trip. In addition, a PORV setpoint of 2450 assures that the PORV will not be activiated (Ref. 1). The addition of the reactor trip signal initiated on turbine trip results in an improved safety margin for this event.

8.3.8 Station Blackout (Loss of AC) (FSAR Section 14.1.2.8)

1. Description

All AC power to the unit is lost, with only battery power available. The reactor and turbine trip, and reactor coolant and feedwater pumps are lost. Core cooling is accomplished through heat rejection to the secondary side using the turbine driven emergency feedwater pump with steam relief to the atmosphere. The analysis is performed starting at full power 2535 Mw (t), and takes credit for a condensate inventory of 200,000 gallons. NNI and ICS instrumentation is taken credit for in controlling the plant when it is powered from the vital ac inverters.

2. Acceptance Criteria

i. DNBR is not less than 1.3.

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ii. Reactor coolant system pressure does not exceed code allowable pressure of 2750 psig.

3. Mitigation

i. Control of the steam driven emergency feedwater by the EFW level control system.

ii. Steam relief through the atmospheric dump and main steam relief valves either by the ICS or in accordance with Emergency procedure 1202-2 and 29.

4. Conclusion

The FSAR analysis of this event remains bounding for the modified TMI-1 plant design. None of the plant modifications being made affect the systems and components which are necessary to mitigate this accident. Since the ICS is powered from the vital ac system, monitoring instrumentation will be powered by the station batteries. The operator will have all of the instrumentation available to bring the plant to a stable shutdown condition.

The extended analysis of this event will determine:

i. When power would have to be restored to maintain stable shutdown.

ii. RCS system pressure response without pressurizer heaters available.

8.3.9 Steam Line Failure (FSAR Section 14.1.2.9)

1. Description

A steam line rupture results in depressurization of the secondary system. This depressurization causes a primary system cooldown causing a DNBR transient and a positive reactivity addition. Blowdown can cause a significant mass and energy addition to containment. Finally, offsite doses can result from the release of secondary side steam to the atmosphere, if steam generator tube leakage exists. The FSAR analysis addresses a variety of break sizes, including the rupture of all four main steam lines outside the reactor building. HPI was not assumed to operate during this event.

2. Acceptance Criteria

i. The core will be maintained in a coolable geometry.

ii. No steam generator tube loss of integrity will result from the pressure/temperature transient.

iii. Offsite doses will be within the limits of 10CFR100.

3. Mitigation

i. Reactor trip on low pressure or high neutron flux.

ii. Feedwater isolation of the affected OTSG as a result of low steam generator pressure.

iii. Isolation of the unaffected steam generator by the turbine stop valves.

iv. Decay heat removal through the unaffected OTSG by manual control of emergency feedwater (Procedure 2203-2.3) and either atmospheric dump valves or the turbine bypass valves if they are available.

v. Containment temperature and pressures are limited by the containment fan coolers (and reactor building spray systems) if reactor building pressure exceeds 28 psig.

4. Conclusion

Recent, detailed analyses of TMI-2 (Refs. 5 through 8) allow broader conclusions about the acceptability of TMI-1 regarding steam line break. The TMI-2 analysis considered additional single failures, the most limiting were the feedwater regulating and turbine stop valve failures. In addition, the reactor core performance was analyzed assuming that: feedwater is not isolated, offsite power is available if results are worse for that case, and both steam generators blow down outside containment. Reference 3 explains why the TMI-2 core performance analysis bounds Unit 1.

At the Cycle 5 refueling outage, the feedwater latching signal was added to the upstream block valves (FW-V-5A/B). The TMI-2 feedwater regulating valve and turbine stop valve failures cases thus bound the TMI-1 design. Although these failures are not a licensing basis for the plant, they do demonstrate the additional safety margins available for this accident.

The difference in design of the main steam isolation valves between TMI-1 and TMI-2 results in less severe containment transients for TMI-1. The Unit 1 valves are a stop/check design, so that they would prevent the blowdown of both steam generators inside containment. Since TMI-1 does not have cavitating venturi's on the emergency feedwater lines, the operator would have to isolate the affected steam generator to prevent containment overpressure. The operator would have approximately 20 minutes to perform this action.

TMI-1 has not analyzed the environmental effect inside containment for the worst case single failure (because of the

stop/check MSIV's, the worst failure is the feedwater regulating valve failure). As noted previously, the blowdown will be less severe than for Unit 2. Although this issue is still being resolved, there are several reasons to expect acceptable results.

i. Heat shrink tubing is being added to splices inside containment. This change was made to TMI-2 prior to receipt of the operating license to resolve this concern.

ii. Much of the equipment which was analyzed and shown acceptable for TMI-2 is also used on TMI-1.

The radiological consequences of the unmitigated steam line break accident have also been addressed on the TMI-2 docket (Ref. 6 and 7). These analysis results demonstrate that worst case doses from a steam line break accident are within the limits of 10CFR100.

8.3.10 Steam Generator Tube Failure (FSAR Section 14.1.2.10)

1. Description

The rupture of a steam generator tube concurrent with 1% failed fuel results in the release of radioactive steam to the environment via the condenser air ejector. Leakage is greater than the capacity of the makeup system, so that the RCS depressurizes.

2. Acceptance Criteria

i. Doses are less than 10CFR100 limits.

3. Mitigation

i. Reactor trips on low pressure.

ii. High pressure injection initiates and maintains primary system pressure and inventory.

iii. Turbine trip isolates the steam generator, and the release path of steam to the environment is via the turbine bypass line, through the condenser to the air ejector.

iv. Cooldown is achieved first via the unaffected steam generator and then through the decay heat cooling system.

4. Conclusions

There have been no plant changes which change the results of this analysis. Results are still valid and acceptable.

8.3.11 Fuel Handling Accident (FSAR Section 14.2.2.1 and References 8 through 10)

1. Descr[illegible]

ailure of a spent fuel assembly, either in the fuel handling building or inside the containment building can result in release of radioactivity to the environment. The fuel ndling accident in the fuel handling building considers a 72 hr. decay period for the fuel with the release of gap activity from the entire row of fuel pins on one assembly. 100% of the noble gases and 1% of this iodine inventory is released from spent fuel pool. The fuel handling accident inside containment assumed failure of an entire assembly, filtration by the refueling canal water, and release via the purge exhaust filtration system.

2. Acceptance Criteria

i. Doses should be appropriate within the guidelines of 10CFR100 (less than 100 REM).

3. Mitigation

i. Filtration of releases through the fuel handling building ventilation system.

ii. Filtration of releases by the purge exhaust filter system for the accident inside containment.

iii. Meteorological dispersion of 6.8×10^{-4} sec/m^3 for the accident initiating inside containment.

4. Conclusion

The plant design changes do not affect the mitigation of the fuel handling accident inside containment. Results are still within the acceptance criteria.

The partitioning of the fuel handling building between Unit 1 and Unit 2 does not affect the consequences of this accident because each unit has its own HVAC system. A Unit 1 fuel handling accident would still be mitigated by the Unit 1 ventilation system.

8.3.12 Rod Ejection Accident (FSAR Section 14.2.2.2)

1. Description

Failure of a pressure barrier component could result in the rapid ejection of a control rod from the core. A power excursion and leakage of radioactive primary system fluid to the secondary side would result. Releases to the environment result both from releases via the secondary system and from leakage from containment.

2. Acceptance Criteria

i. The reactor coolant pressure boundary is not further degraded as a result of the ejected rod (no reactor vessel deformation).

ii. Offsite doses are within the limits of 10CFR100.

iii. Radially averaged enthalpy should not be greater than 280 cal/gm at any axial location in any rod.

3. Mitigation

i. The power excursion is limited by the Doppler coefficient.

ii. The power excursion is terminated by reactor trip on high pressure or high flux.

4. Conclusions

The lower high pressure trip setpoint results in increased safety margins over the FSAR analysis. Improvements to the containment isolation signal (radiation +Rx trip) make release of fluid from the containment building less likely.

8.3.13 Feedwater Line Break Accident (TMI-2 FSAR, S3-22.49)

1. Description

This event has not been analyzed for TMI-1. The following description is based on FSAR analyses for TMI-2. A loss of feedwater flow results in a loss of heat sink, primary system heatup, increased pressurizer level and pressure, and reactor trip on high RCS pressure. The TMI-2 analysis assumes a complete loss of feedwater due to a break upstream of the first feedwater line check valves. No analysis of loss of feedwater due to pump trip or valve closures were analyzed. The loss of feedwater flow due to the postulated break is analyzed as an immediate loss of flow, which results in a bounding analysis for loss of feedwater events. The reactor is initially at 2772 Mw(t). Assumptions were made to provide two worst case scenarios one for containment, and one for primary system conditions.

A double ended rupture (with a blowdown area limited by the feedwater nozzle area) was analyzed; steam generators are assumed to have a fouled inventory of 62,500 lbs., and emergency feedwater is assumed to be at full flow within 40 seconds. The loss of feedwater is not directly calculated but taken as a conservative loss of heat demand (100-0% in 5 seconds for the affected generator and 100-0% in 20 seconds for the unaffected generator).

1228 039

2. Acceptance Criteria

i. Core thermal power shall not exceed 112% of rated power.

ii. Reactor coolant system pressure shall not exceed code allowable limits of 2750 psig.

3. Mitigation

i. Reactor coolant system trip on high pressure.

ii. The secondary system heat sink is restored by initiation of emergency feedwater to full flow within 40 seconds. Heat removal is through the turbine bypass valves or main steam relief valves.

4. Conclusions

Results of the TMI-2 feedwater line break accident have become bounding for Unit 1 with the addition of a feedwater line break initiating signal. The addition of reactor trip or loss of feedwater increases the safety margin over the TMI-2 analysis. Lowering of the high pressure trip setpoint also increases safety margins since reactor trip will be initiated sooner. The RCS heatup is thus reduced. PORV operation was not assumed in the feed line break analysis, so that the increase in the valve setpoint does not affect analysis results. The PORV would actuate for the worst case feedline break accident analyzed in the TMI-2 FSAR.

8.3.14 Waste Gas Decay Tank Rupture (FSAR Section 14.2.2.5)

1. Description

The rupture of a waste gas decay tank would result in radiological releases via the plant ventilation system. The tank contents as calculated assuming the activity evolved from degassing the primary coolant system after operation with 1% failed fuel.

2. Acceptance Criteria

Doses shall not exceed the limits of 10CFR100.

3. Mitigation

Elevated release of activity from the unit vent.

4. Conclusions

This analysis has not been changed as a result of any plant modifications.

1228 040

8.3.15 Small Break Loss of Coolant Accidents (LOCA)

1. Description

Small break LOCA's are piping ruptures whose break areas range from as small as 0.005 ft.^{2} to as large as 0.5 ft.^{2}. These LOCA's may or may not involve depressurization of the Reactor Coolant System (RCS).

2. Acceptance Criteria

i. Local fuel cladding oxidation (metal water reaction) shall not exceed 0.17 times the total cladding thickness, or .05 the overall cladding mass.

ii. Peak Cladding Temperature (PCT) shall not exceed 2200°F.

iii. A coolable geometry shall be maintained.

iv. Long term cooling shall be assured.

3. Mitigation

i. Inventory will be maintained by the high pressure injection system.

ii. Emergency Feedwater flow within 20 minutes of very small break LOCA's allows depressurization of the RCS and allows sufficient inventory addition by the HPI system to maintain core cooling.

4. Conclusion

Pursuant to NRC regulations (10CFR50.46) and 10CFR50 Appendix K) B&W performed generic LOCA analyses of their 177 fuel assembly lowered loop plants. Initially this work was performed to meet the Interim Acceptance Criteria (IAC) and documented in BAW-10052. Later, the analyses were revised to the Final Acceptance Criteria (FAC) using the approved Appendix K model (BAW-10104). The FAC analysis results were documented in BAW-10103.

The work performed for BAW-10052 was used as the basis for the small break LOCA lcoation and size sensiti ty study and therefore no new work was performed for B. 0103 other than analysis of three specific break sizes and locations (0.04 ft.^{2}, 0.44 ft.^{2} and 0.5 ft.^{2} break sizes).

In April 1978, B&W identified an error in their ECCS model. The error was also evident in the model used for the BAW-10052 sensitivity studies and therefore the basis for the acceptability of the small break analysis was eliminated. B&W performed additional small break studies using the corrected model. The revised analyses are documented in a letter from J. H. Taylor, B&W to S. A. Varga, NRC dated July 18, 1978. These analyses cover break sizes 0.04, .055, .07, .085, 0.1, 0.15, 0.2, 0.3, 0.13, and 0.17 ft.^{2}.

Key assumptions for the small break LOCA analyses versus the TMI-1 plant design are given below:

	BAW-10103 Generic	TMI-1
Reactor Power (MWt)	2772	2335
Reactor Trip (psig)	1900	1900*
RC Pumps (LOOP)	Coastdown	Coastdown
AFW Available**	Yes-40 sec.	Yes****
ESFAS HPI (psig)	1600	1500
Operator Action	Yes-cross-connect	none***
HPI Distribution	70% to Core within 10 min.	70% to core from time zero***
HPI Flow (gpm)	450 at 600 psig	500 at 600 psig

* Variable low pressure at full power.

** Amount assumed for generic analyses 550 gpm which is less than the minimum 900 gpm available for TMI-1.

*** Prior to startup TMI-1 will install HPI injection leg cross connects and flow control devices to eliminate operator action to cross connect HPI and equalize flow in all four injection legs.

**** For worst case LOCA in which offsite power is lost, EFW is initiated by the control grade loss of feedwater signal.

In all cases, TMI-1 plant specific information is as conservative or more conservative than the generic assumption.

Since the TMI-2 accident, greater focus has been placed on small break LOCA's and the capability of the ECCS to mitigate them. Problems such as those discussed in Reference 21 (where the pressurizer stays full due to the loop seal arrangement despite loss of RCS inventory) have been addressed. These studies are documented in B&W's "Evaluation of Transient Behavior and Small Reactor Coolant System Breaks in the 177 Fuel Assembly Plant" May 7, 1979 (Reference 2). Breaks of 0.01, 0.02, and 0.07 ft.^{2} are analyzed utilizing varying assumptions on the availability and timing of AFW and HPI. These analyses use the same initial assumptions as used in BAW-10103 except that ESFAS is assumed to occur at 1350 psig. Therefore, they are also bounding assumptions for TMI-1 except for the distribution of HPI flow as discussed below. The analysis in Reference 2 also established that EFW flow is not required less than 20 minutes before any steam line break accident.

1228 042

In Reference 2, credit is taken for operator action to initiate HPI or EFW. No mention is made as to whether whether operator action includes the time necessary to cross connect HPI as required in B&W's other small break accident analyses. TMI-1 will complete the installation of permanent cross connection of the HPI prior to startup, therefore, operator action will not be necessary. All of the B&W small break LOCA analyses assume essentially equal backpressure for all four HPI injection points. This assumption is the basis for the 70%/30% flow split of HPI (assuming a single failure of one HPI train) between the core and the break respectively, after cross connection is accomplished. Such an equal backpressure would not exist given an HPI line rupture. The back pressure on the broken HPI leg would be essentially zero and therefore the HPI loss out the break could be high resulting in inadequate injection to the core.

The criterion established by B&W for the small break analysis requires that 70% of the total flow for one HPI pump be injected into the broken legs of the reactor coolant system. This criteria applies to a 2772 MW thermal 177 fuel-assembly plant. For TMI-1 with a licensed core power of 2535 MWt, the 70% - 30% criterion can be relaxed in direct proportion to the power reduction. This is justified based on the fact that the decay heat load following a small break LOCA is proportional to power and therefore cooling requirements will be directly proportional to the power at which the plant has operated. Therefore, for TMI-1, the acceptable flow split can be relaxed to 64% - 36%. The 64%/36% flow split would not be obtained for an HPI line break as explained above. Therefore, operator action would be required to isolate the ruptured HPI line. The need to isolate could be determined by observing the individual flow indicators for the HPI legs. The high flow leg would then be isolated. This action would be contrary to the operators instinct and would require considerable judgment since the initial flow imbalance may not be dramatic. Since too great a chance for operator error (error of omission) exists, cavitating venturis will be added to the injection legs to limit flow in the broken leg.

The venturis have been sized to limit flow in each leg to 137.5 gpm when only one high pressure injection pump is operating and Reactor Coolant System is at atmospheric pressure. The venturi design ensures that for the worst case HPI line break condition, the 64%/36% flow split can be achieved when Reactor System Pressure is less than 1500 psig. At RCS pressure conditions greater than 1500 psig, a flow split beyond the 64%/36% acceptance criteria will occur. B&W has reviewed this situation and judged the cavitating venturi performance is acceptable. This conclusion is based on the fact that under HPI line break conditions, the Reactor Coolant System will not expend significant time above 1500 psig and that during the time the RCS is above 1500 psig the cavitating venturi ensures that there is significant flow of high pressure injection into the RC system. B&W also notes that a much larger small break than a HPI line break sets the generic flow split criteria and therefore for a HPI line break the flow split criteria can be relaxed.

In addition to the benefits discussed above, the venturis provide two added benefits. First, they balance flow of the injection legs under all other small break conditions such that TMI-1 flow split will be within the bounds of the generic analysis (i.e., 70%/3-% flow split). Secondly, the cavitating can be relaxed.

8.3.16 Large Break Loss of Coolant Accidents (Reference FSAR Section 14.2.2.3)

1. Description

Break sizes in the reactor coolant system (RCS) greater than 0.5 ft.^{2} are classified as large break loss of coolant accidents (LOCA's). These breaks involve rapid depressurization of the RCS and are accompanied by rapid increases in containment pressure. Offsite doses are calculated from the design basis radioactivity release to containment, and the design basis containment leak rate.

2. Acceptance Criteria

i. Peak fuel clad temperature does not exceed 2200°F.

ii. The core is maintained in a coolable geometry.

iii. Local fuel cladding oxidation (metal water reaction) shall not exceed 0.17 times the total cladding thickness of .05 times the total cladding mass.

iv. Offsite doses are within the limits specified by 10 CFR 100.

3. Mitigation

i. Core flood tank actuation at 600 psig to establish water inventory.

ii. Low pressure injection system flow below 200 psig to establish core cooling for the remainder of the accident.

iii. Building spray addition to put iodine in solution with the containment water volume thus preventing release to the environment.

iv. Containment leak tightness to limit radioactivity releases.

4. Conclusion

The calculated offsite dose resulting from the design basis LOCA will increase as a result of the deletion of sodium thiosulfate from the building spray system. Doses will still

be within the limits of 10 CFR 100. Dose calculations performed for TMI-2 (see TMI-2 FSAR, Section 15 and Reference 5) demonstrate that design basis LOCA doses are within the limits of 10 CFR 100. The TMI-2 dose calculations were performed taking no credit for sodium thiosulfate. Since Unit 2 has a slightly large thermal power level and allowable containment leak rate, then Unit 2 dose calculations conservatively bound the worst case LOCA do e for TMI-1.

8.4 SUMMARY AND CONCLUSIONS

Plant modifications to TMI-1 allow the plant analyses to bound the expected plant behavior (see below). In some cases, analysis for TMI-2 have been referenced because they either analyze events that are not in the TMI-1 FSAR (feedline break) or provide additional assurances of safety margins (steam line break).

1. Raising the PORV setpoint and lowering the high pressure trip setpoint affects all of the pressurization transients in the FSAR. Safety margins are improved since the high pressure trip setpoint has been lowered. No credit was taken for operation of the PORV, so that raising the valve setpoint has no effect on the FSAR analysis results.

   The combined effect of the PORV and RPS setpoint changes are to decrease the probability of PORV operation. The integrity of the primary coolant system will be challenged less frequently, so that this change is in the conservative direction. It should be noted that this modification could result in more frequent plant trips.

2. Reactor trip resulting from loss of feedwater results in improved safety margins for loss of feedwater events and does not degrade plant response for any accidents/transients.

3. Reactor trip as a result of turbine trip increases safety margins for the loss of feedwater or feed line break analyses. The effect of retaining or deleting plant features that permitted this event to occur without a reactor trip is being analyzed.

4. The addition of emergency feedwater initiating signals for the feedline break accident makes the TMI-2 feedwater line break accident analysis bounding and conservative for TMI-1. This event has additional safety margins beyond the TMI-2 analysis since both turbine and feedwater trips result in a reactor trip. This earlier reactor trip will result in a smaller heatup of the primary system.

5. Modifications to the high pressure injection system will allow adequate HPI flow for the spectrum of LOCA's. System performance is not degraded for any other accidents/transients in which HPI flow is initiated.

5. Modifications to the high pressure injection system will allow adequate HPI flow for the spectrum of LOCA's. System performance is not degraded for any other accidents/transients in which HPI flow is initiated.

6. Upgrading of instrumentation inside containment assures that instrumentation will be functional in the postulated accident environments.

7. Automated switchover of the BWST to the recirculation mode provides additional assurance that switchover will occur within the correct level band. Correct operator action had always been assumed in previous LOCA analyses. The automated switchover achieves the same function requirement by means of a safety grade control system.

8. Dose calculation performed for TMI-2 demonstrate that the requirements of 10CFR100 are met even after sodium thiosulfate is deleted.

9. Partitioning of the fuel handling building does not degrade the capability of the building HVAC to mitigate fuel handling accidents. Filtration of radioactivity will still be accomplished in accordance with the licensing basis for the unit.

10. The transition to natural circulation following a complete loss of feedwater will be demonstrated by a startup test.

11. An analysis of the station blackout will be performed to determine what specific actions would be required to bring the plant to a safe shutdown condition.

12. A PORV setpoint of 2450 psig does not result in unacceptable interactions between the PORV and the pressurizer safety valves, whose setpoint is 2500 psig.

1228 046

REFERENCES

1. Three Mile Island Unit 1 Nuclear Station, Final Safety Analysis Report, USNRC Docket No. 50-289.

2. "Evaluation of Transient Behavior and Small Reactor Coolant System Breaks in the 177 Fuel Assembly Plant," Volumes I & II, Babcock and Wilcox, May 7, 1979.

3. "GPUSC Safety Evaluation Report for Three Mile Island Unit 1 Cycle 5 Reload," dated March 1979.

4. Letter, Met-Ed (J. G. Herbein) to USNRC (R. W. Reid) on "High Pressure Trip and Pressurizer Code Safety Valve Settings," GQL-0669, April 17, 1978.

5. "Supplement No. 2 to the Safety Evaluation Report by the office of Nuclear Reactor Regulation, Three Mile Island Nuclear Station Unit No. 2, Docket Number 50-320," USNRC, NUREG 0107, dated February, 1978.

6. Letter, Met-Ed (J. G. Herbein) to USNRC (S. A. Varga), on "Analysis of Fuel Performance During a Steamline Break for TMI-2," License No. CPPR-66, Docket No. 50-320, dated November 18, 1977.

7. Letter, Met-Ed (J. G. Herbein) to USNRC (S. A. Varga), on "Response to Staff Questions on Analysis of Fuel Performance During a Steamline Break," dated December 9, 1977.

8. Letter, Met-Ed (J. G. Herbein) to USNRC (R. W. Reid) on "TMI-1 Fuel Handling Accident Inside Containment," GQL-0460, dated April 20, 1977.

9. Letter, USNRC (R. W. Reid) to Met-Ed (J. G. Herbein), dated February 4, 1979.

10. Letter, Met-Ed (J. G. Herbein) to USNRC (R. W. Reid) on "TMI-1 Fuel Handling Accident Inside Containment, "GQL-0460, dated May 8, 1979.

11. ECCS Analysis of B&W's 177-FA Lowered Loop NSS, BAW-10103, Rev. 2, Babcock & Wilcox, April 1976.

12. USNRC to Met-Ed "Order for Modification of License," Docket No. 50-289, May 19, 1978.

13. Letter, Met-Ed (J. G. Herbein) to USNRC (R. W. Reid), on "Small Break LOCA," GQL-0809, May 3, 1978.

14. Safety Evaluation and Environmental Impact Appraisal by the Office Nuclear Reactor Regulation, Supporting Amendment No. 65 to Facility Operating License No. DPR-47, Amendment No. 62 to Facility Operating License No. DPR-55 Duke Power Company, Oconee Nuclear Station, Units Nos. 1, 2 and 3, Docket Nos. 50-269, 50-270, and 50-287, October 23, 1978.

15. TMI-1 Fuel Densification Report, BAW-1389, Babcock & Wilcox, June 1973.

REFERENCES - (Cont'd)

16. GPUSC Safety Evaluation Report of B&W's TMI-1 Cycle 4 Reload Report, dated January 13, 1978.

17. GPUSC Safety Evaluation of B&W's TMI-1 Cycle 3 Reload Report, dated January 21, 1977.

18. Office of Standards Development, U.S. Nuclear Regulatory Commission, Regulatory Guide 1.70, "Standard Format and Content Guide, Rev. 3, LWR Edition.

19. "Order and Notice of Hearing, Docket 50-289," dated August 9, 1979, USNRC.

20. "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979.

21. Michelson, C. "Decay Heat Removal During a Very Small Break LOCA for a B&W 205-Fuel Assembly PWR". January, 1978.

1228 048

TABLE 9.2-1
Restart Modification Additional Loads

Items	Title	Additional Load in KW	MCC or Dist. Panel	Bus
	Upgrade Decay Heat System			
	Vent Valve A	0.7	DC Pool 1E	
	Vent Valve B	0.7	DC Pool 1F	
	Vibration Monitor	0.6	MCC 1B	Bus 1S
2.1.1.1	Reactor Trip	Neg.		
2.1.1.6.3.1	Incore Thermocouples	Neg.		
2.1.1.5	Containment Isolation	less than 1		
2.1.1.2	Valve Position Indication	0.23	PNL ATB	Inverter 1E
	Computer	Less than 0.5		Inverter 1E
2.1.1.2	Power Operated Relief Valve Position Indication	Less than 1		
2.1.1.4	H_2 Recombiner			
	A bus heater & blowers	45	MCC 1A	1P
	B bus heater & blowers	45	MCC 1B	1S
	space heater	0.8	PNL CT-E	1S
	isolation valves	0.53	DC PNL 1A	
	isolation valves	0.53	DC PNL 1B	
	position indication	0.025	Swing DC PNL 1M (PNLS 1A and 1B)	
2.1.1.7	Emergency Feedwater	Less than 1		
	Changes to HPI System to Accommodate Small Break LOCA	0.05		Inverter 1E
2.1.1.3	Pressurizer Heaters connected only on loss of offsite power and no E.S.			
	Heaters to A System	126 KW		1P
	Heaters to B System	126 KW		1S
2.1.1.6.3.3	P_{sat} Alarm	less than 1		

1228 049

TABLE 9.2-1 (Cont'd.)

Restart Modification Additional Loads

Items	Title	Additional Load in KW	MCC or Dist. Panel	Bus
2.1.1.6	Reactor Coolant System Temp.	Neg.		
	Reactor Building Sump Water Level	Less than 1		
	Reactor Building Cooling Fan Motors	No Requirement		
	Fire Protection Change	later		

NOTES

1. Items marked "neg." indicates less than 100 watts load and the source has not been determined.
2. Items marked "no requirement" indicates no load or no additional load requirements.
3. Items marked "later" indicates that changes are unknown. This information will be supplied when available.

Recommendation	Response
Item 8	Section 11.2.1
Item 9	Section 2.1.1.5.3
Item 10	Section 3.1.3
Item 11	(Later)
Item 12	Section 3.1 Table 3.1-1 (AP 1044)
IEB 79-05B	
Items 1 & 2	Sections 3.1.4 and 6.2
Item 3	Sections 11.2.3 and 8.1 (Based on B&W analyses submitted May 7, 1979)
Item 4	Sections 3.1.1 and 2.1.1.1
Item 5	Section 2.1.1.1
Item 6	Section 3.1 Table 3.1-1 (AP 1044)
Item 7	Section 11.2
IEB 79-05C	
Item 1	Section 3.1.1
Item 2	(Later)
Item 3	Section 3.1.
Item 4	Sections 3.1.1 and 6.0
Item 5	See NUREG 0578 Item 2.1.9 below
Item 1 (Long Term)	Sections (later) and 8.2.4
3. Emergency Plan Upgrading	Section 4.0
4. TMI-1/TMI-2 Radwaste Ventilation and Sampling Separation	Section 7.2
5. TMI-1 Radwaste Management Capability	Section 7.3
6. Organization and Resources	Section 5.0 to be supplemented separately

1228 051

Recommendation		Response
7.	Financial Qualifications	To be Submitted Separately
8.	TMI-2 Lessons Learned Recommendations - NUREG 0578	
	2.1.1	Section 2.1.1.3
	2.1.2	Met-Ed will participate in the EPRI/NSAC program to conduct performance testing of PWR relief and safety valves. We will verify that the program is applicable to TMI-1. It is understood that this program will be reviewed with the NRC prior to testing to ensure that the intent of NUREG-0578, Recommendation 2.1.2, is satisfied. We believe that substantive test data can be obtained by July, 1981. However, scheduling of the test facility, acquisition of valves to be tested, and the possibility of extensive retesting could result in a longer schedule.
	2.1.3.a	Section 2.1.1.2
	2.1.3.b	Section 2.1.1.6
	2.1.4	Section 2.1.1.5
	2.1.5	Section 2.1.1.4
	2.1.6	(Later)
	2.1.7	Section 2.1.1.7
	2.1.8	(Later)
	2.1.9	Sections 3.1.1, 6.0 8.1 and (Later)
	2.2.1.a	Section (Later)
	2.2.1.b	Section 5.0
	2.2.1.c	Section (Later)
	2.2.2	Section 4.0
	2.2.3	Not Applicable until NRC Regulations are revised

dropped approximately 219 inches and T_{ave} dropped to 536°F following the trip; both of these related parameters exceeded their normal response to a turbine trip. The apparent cause was the failure of two main steam safety valves, MS-V21A and MS-V20B, to reseat. This allowed an initial drop in OTSG header pressure to 950 psi until the turbine bypass valves adjusted to compensate for this additional steam relief. Although this was a deviation from the expected performance it is not considered to be significant since no Limiting Conditions for Operation were violated, pressurizer level remained on scale, and the turbine bypass valves were more than adequate to control header pressure.

Summary of Corrective Action

Since the above review did not identify any significant deviations from expected performance, no major corrective actions were undertaken. Minor corrective action such as rechecking of instrument setpoints were performed. Details concerning each transient that was reviewed and the specific corrective actions taken are included in Appendix 10A. Neither of these transients were reported as reportable occurrences.

1228 053

APPENDIX 10A

1228 054

REACTOR TRIP # 11 8/30/74 @ 1312

CAUSE OF REACTOR TRIP Variable Pressure/Temperature

CAUSE OF TURBINE TRIP High Vibration #11 Bearing

REACTOR POWER AT TIME OF TRIP 75 %F.P.

OPERATOR ACTIONS Manual reduction of feed flow.

POST TRIP REVIEW

TIME SINCE TRIP (Seconds)	TAVE (°F)	TH (°F)	Tc (°F)	Pressurizer Level (inches)	R.C. Pressure (PSIG)
-300	578.45	595.9	561	247	2153
-90	583.80	597	570.6	277	2121
-60	592.9	603.3	582.5	319	2284
-30	606.4	612	600.8	405	2214
0	599.76	600.77	598.75	363	1955
60	576.5	576.9	576.1	209	1730
120	563.38	563.67	563.1	135	1662
180	558.4	558.60	558.5	123	1670
240	557.88	557.87	557.9	133	1767
300	558.48	558.47	558.5	149	1865

1228 055

Rx. Trip #11 8/30/74 @ 1312

I. Events Leading Up to the Trip

The reactor was operating at 75% power with steady state conditions. All ICS stations were in AUTO. Vibration of the Number 11 bearing on the main turbine increased rapidly to the trip point (8 mils.). This caused a turbine trip.

In the one minute time span immediately following the turbine trip, the secondary safety valves lifted, the p mary system dropped slightly and the feedwater flow was cut back (See Enclosure II). The loss of steam load and the decrease in feedwater flow caused the primary pressure to increase rapidly to the electromatic relief valve setpoint. While the electromatic was lifting t decrease the RC pressure, the feedwater flow was still being cut back drastically. Feedwater demand had been taken into manual at so point and manually reduced, but it isn't clear on the data and charts exactly when this occured. It appears that feedwater had cut back automatically at first and then again manually. The result was that Tave began increasing rapidly as the primary pressure was decreasing. The operator tried to manually increase feedwater flow to correct his error but the reactor tripped on Variable Temp./Press. before the correction could be made.

II. Integrated Control System Response

Before the reactor trip, all ICS stations were in AUTO. The turbine tripped at 1310:54 and at 1310:57 a Unit Load Limited by Feedwater Flow alarm was received along with a Steam Gen. B on BTU Limit alarm. At 1310:59 a Unit Load Limited by Reactor alarm was received and the reactor began running itself back to 15% power as designed. At the same time a Steam Gen. A on BTU Limit alarm came in. At 1311:00 the Feedwater Flow Limit cleared but came right back in at 1311:01. The Steam Gen. A on BTU Limit cleared at

1228 056

1311:04. The Unit Load Limited by Feedwater Flow alarm did not clear until 30 seconds after the reactor trip. When the first Feedwater Flow alarm (1310:57) was received, the feedwater flow began running itself back in AUTO. Shortly thereafter, the CRO took Feedwater demand into MAN. and ran feedwater flow down even faster.

ICS response post trip was per design.

III. Operator Action

Before the trip, the operators were observing control rod movement because of a recent deboration. When the turbine tripped off they put their attention on keeping the reactor from tripping. When the primary CRO saw pressure decreasing due to electromatic relief lift he placed feedwater demand in manual and began reducing feedwater flow to stop the pressure drop, but he realized he had dropped it too much when he saw Tave increasing rapidly. He began increasing feedwater flow, but the reactor tripped before he could recover the feedwater flow.

After the reactor trip, the operators carried out reactor trip and emergency procedures.

IV. Overall Plant Response

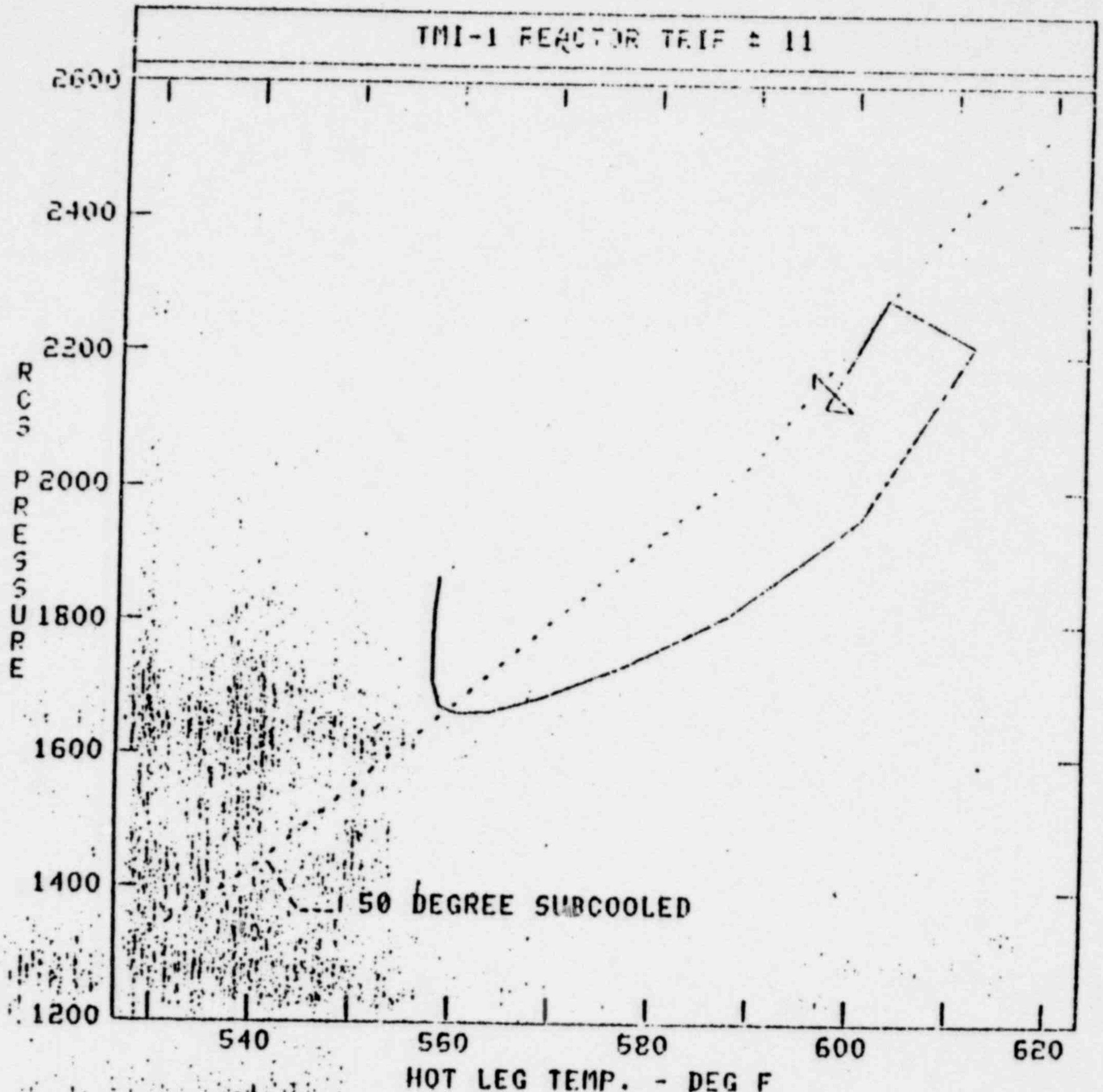
Immediately following the turbine trip the reactor began to run back in power as designed. It reached about 25% power before the reactor tripped. The turbine trip caused the secondary safety valves to lift. They remained lifted approximately 30 minutes and 6 to 10 of them lifted.

The loss of steam load caused the primary system pressure to increase until the electromatic relief valve lifted. The lifting of this relief caused the reactor coolant drain tank rupture disc to fail. There is no indication of abnormal operation of the electromatic relief valves. It opened for approximately 35 seconds and then reseated.

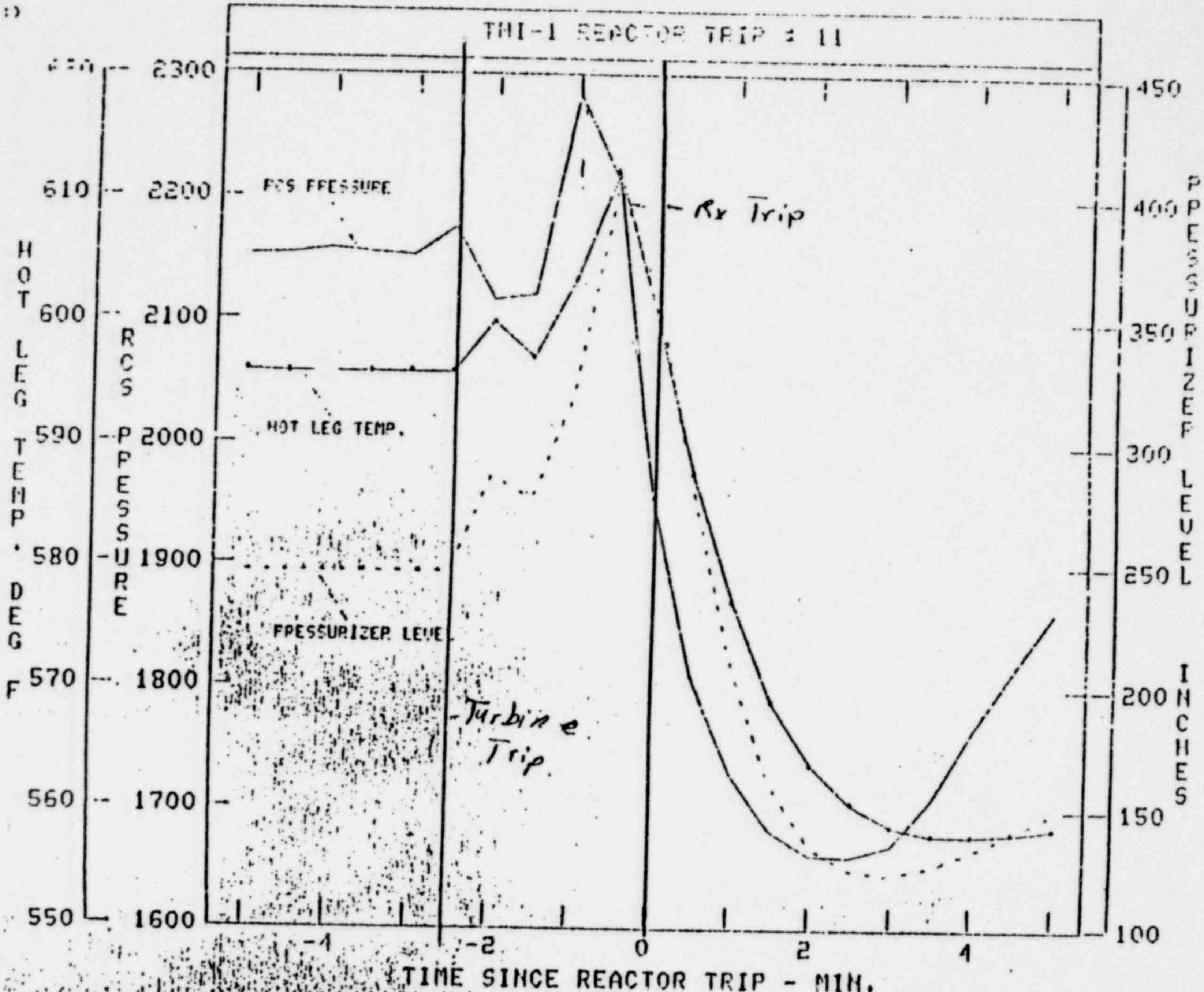
The turbine header pressure was 890 psi. before trip and hit a maximum of 1055 psi. The OTSG "A" Level was 177 inches before the trip and went to a minimum of 28 inches. OTSG "B" was at 170 inches and dropped to about 10 inches. During the transient the charts show a maximum R.C. Pressurize Level of greater than 400 inches and a minimum of 100 inches. The R.C. Pressure (WR) hit a maximum of 2309 psia. and a minimum of 1691 psia. Tave reached a maximum of 606.5°F and then cooled down to 532°F after the reactor trip. Finally, R.C. Pressure (NR) reached a maximum of 2295 psia. Tables and charts of these values can be found in the enclosures.

V. Recommendations

1. Have General Electric representatives evaluate the problem with #11 bearing.
2. Check setpoints on electromatic relief.
3. See attached letter from B&W. PORC should recommend GAI evaluate capacity of cooling system.
4. Instrument Department looking at some method of starting recorders in fast speed based on input from plant parameters during trips.


TMI-1 REACTOR TRIP # 11
RCS PRESSURE
2600
2400
2200
2000
1800
1600
1400
1200
540
560
580
600
620
HOT LEG TEMP. - DEG F
50 DEGREE SUBCOOLED

1228 059



POOR ORIGINAL

1228 060

POOR ORIGINAL

REACTOR TRIP # 12 3/30/75 @ 0010

CAUSE OF REACTOR TRIP High Pressure

CAUSE OF TURBINE TRIP Loss of 125VDC power to EHC

REACTOR POWER AT TIME OF TRIP 100 %F.P.

OPERATOR ACTIONS/Remarks: MS-V21A & MS-V20B did not reseat properly. Started MU-P1A, opened MU-V14A, closed MU-V3, Took manual control of bypass values (turbine).

POST TRIP REVIEW

TIME SINCE TRIP (Seconds)	TAVE (°F)	TH (°F)	TC (°F)	Pressurizer Level (inches)	R.C. Pressure (PSIG)
-30	578	600	556	235	2146
0	562.5	567	558	237	1802
30	548	550	546	135	1724
60	540.5	543	538	44	1697
90	536	540	532	20	1702
120	536.5	539	534	16	1758
150	539	540	538	29	1852
180	541.5	542	541	50	1952
240	545.5	546	545	90	2133

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Rx. Trip #12 3/30/75 @ 0010

I. Events Leading Up to the Trip

The unit was operating at full power with steady state conditions. The "A" start up block valve was closed and the "B" main feed pump was in hand. All other ICS stations were in AUTO. There was no indication of any problems. At 0010 on March 30, 1975, the turbine tripped. The operator received approximately ten overhead SCAM alarms and then checked the control rod PI panel and noted in limit lights for all control rod groups with the exception of group 8, indicating the reactor had tripped. The operator then began trying to stabilize the plant. This all took place in a five to ten second time span.

II. Integrated Control System Response

Before the reactor trip all ICS stations, except "B" main feed pump, were in AUTO. An erroneous signal from a faulty 701 relay indicated a loss of 125 volt DC supply to the turbine EHC system. This immediately resulted in a turbine trip. In the next four seconds, the following events occurred: ICS went into tracking mode, reactor power began decreasing, T_H began decreasing, T_C began increasing, RC pressure increased, pressurizer level increased, feed water flow decreased. Four seconds after the turbine tripped, the RC pressure reached 2355 psi and the reactor tripped. To this point in time the control room operators took no action. RC pressure began to decrease rapidly and the pressurizer level started dropping. The control room operators began to take manual control of the plant in order to stabilize conditions.

III. Operator Action

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The primary system operator was at the console when the overhead alarms began annunciating. He looked up and saw about 10 alarms flashing. One he noticed was high RC pressure. He then noticed the in limit lights for all control rod groups except group 8. By this time, RC pressure and pressurizer level were decreasing, so the operator closed MU-V3, opened

MU-V16B and started MUP-1A. Pressure continued to decrease so the operator opened MU-V14A, thereby adding borated water to the RCS from the BWST.

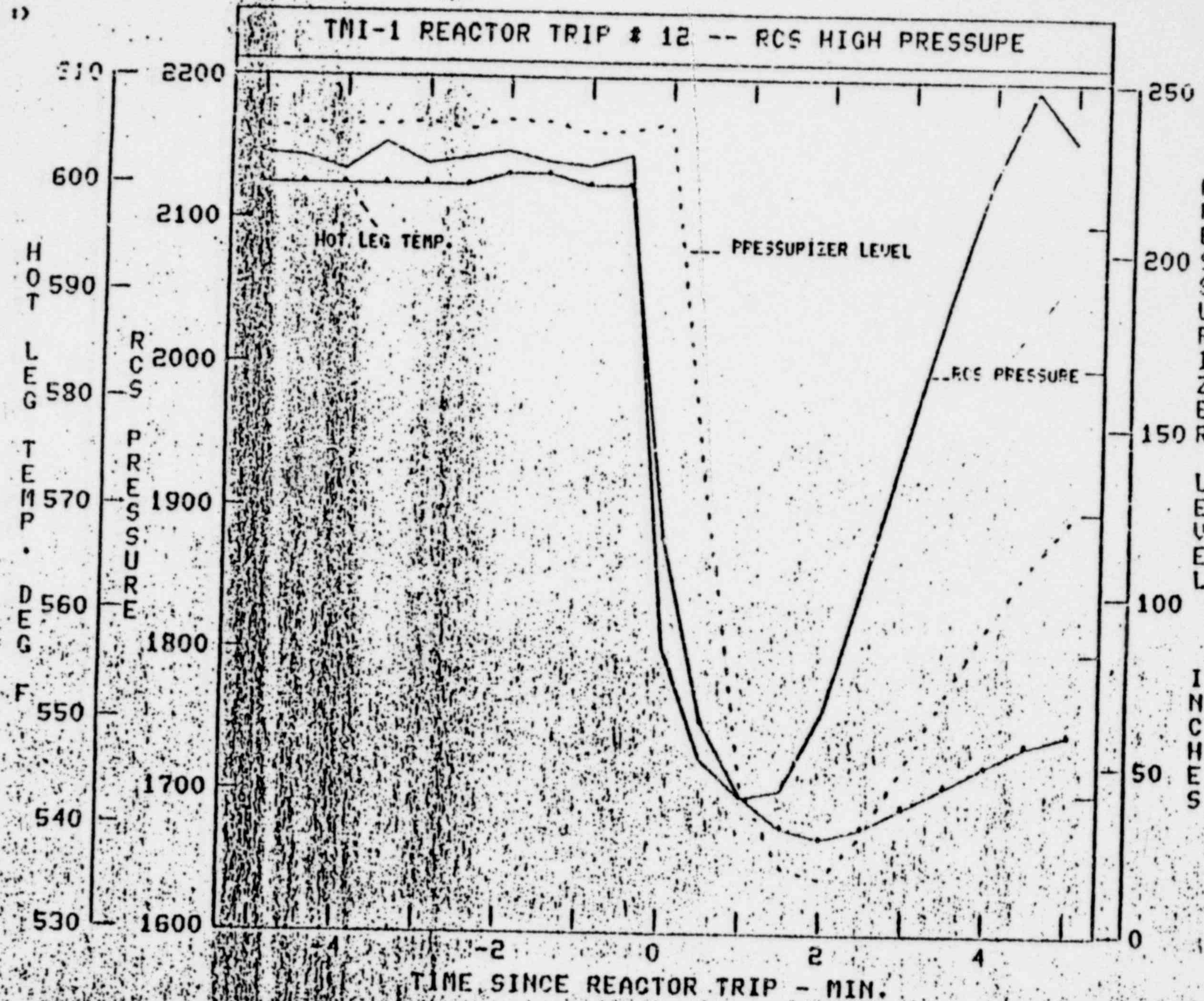
The secondary CRO checked that all generator breakers were open and started all turb -generator oil pumps. He then checked the header pressure which was reading about 1000 psi. The secondary operator took manual control of steam bypass and FW-V16A/B and lowered turbine header pressure to 900 psi. He maintained the OTSG levels at thirty inches.

When conditions had stabilized, the Diamond control station was reset, FW-V16/A&B were placed in AUTO, steam bypass was placed in AUTO, MU-V14A and MU-V16B were closed and MU-P1A was stopped. The above actions indicate the operators correctly carried out the necessary emergency procedures.

IV. Overall Plant Response

Under these circumstances, the turbine trip was inevitable. The plant followed the same sequence of events that took place during the loss of load test from 100% which was performed during startup testing. The reactor tripped four seconds after the turbine trip due to high RC pressure. Most of the secondary system steam safety valves lifted and two remained open for approximately one hour. After the reactor tripped due to high pressure, the RC pressure began decreasing rapidly and pressurizer level dropped. As described previously, the CRO's took the necessary actions to stabilize these conditions. Following short form (<24 hrs.) precritical checks, the reactor was taken critical 5.7 hours after the trip and the turbine was put back on line about eight hours later.

Enclosure 1 provides the computer sequence of events printout. Enclosure 2 provides the alarm printouts. The change of plant parameters with time during the transient can be found in Enclosures 3-5.



POOR ORIGINAL

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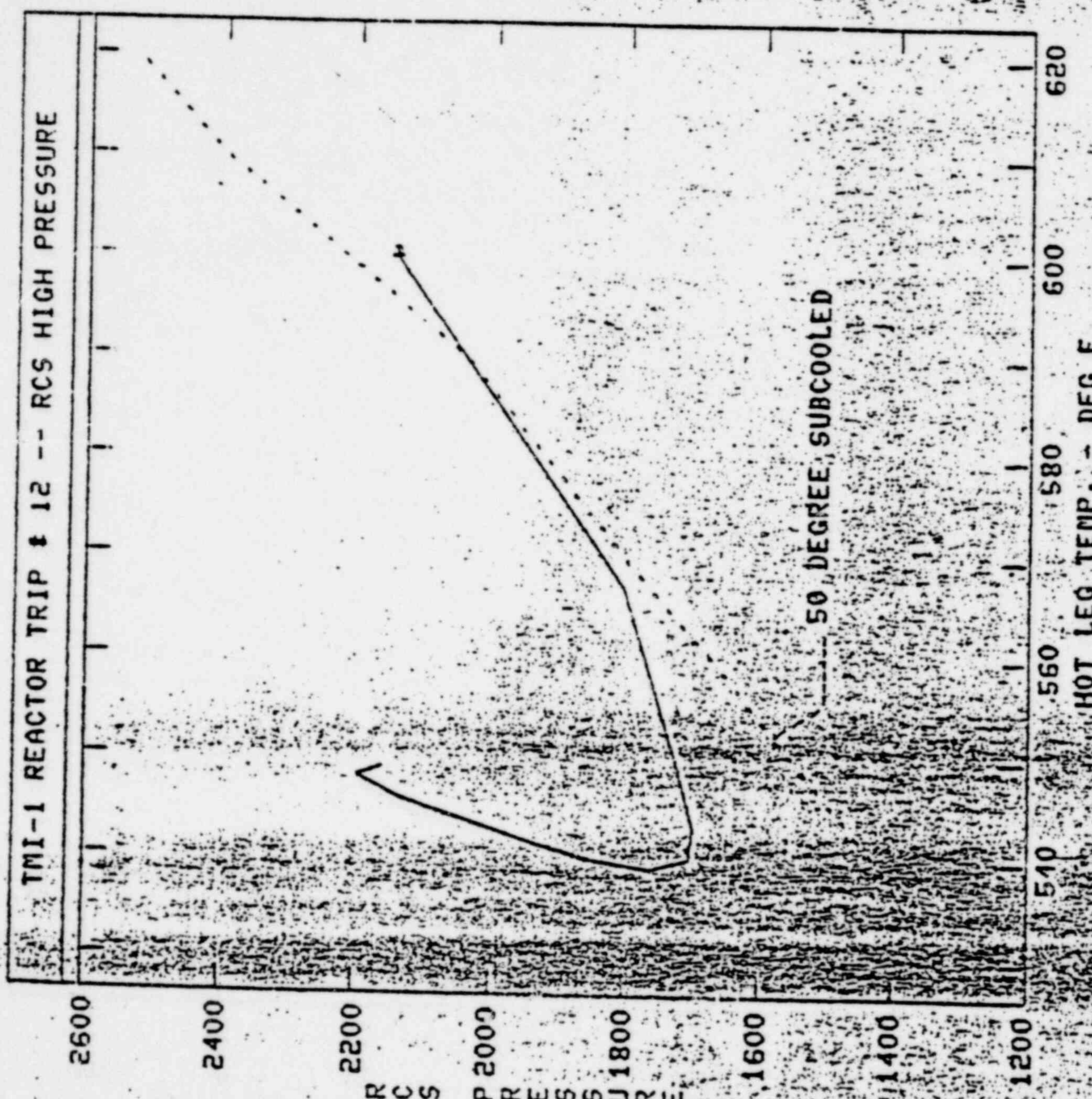

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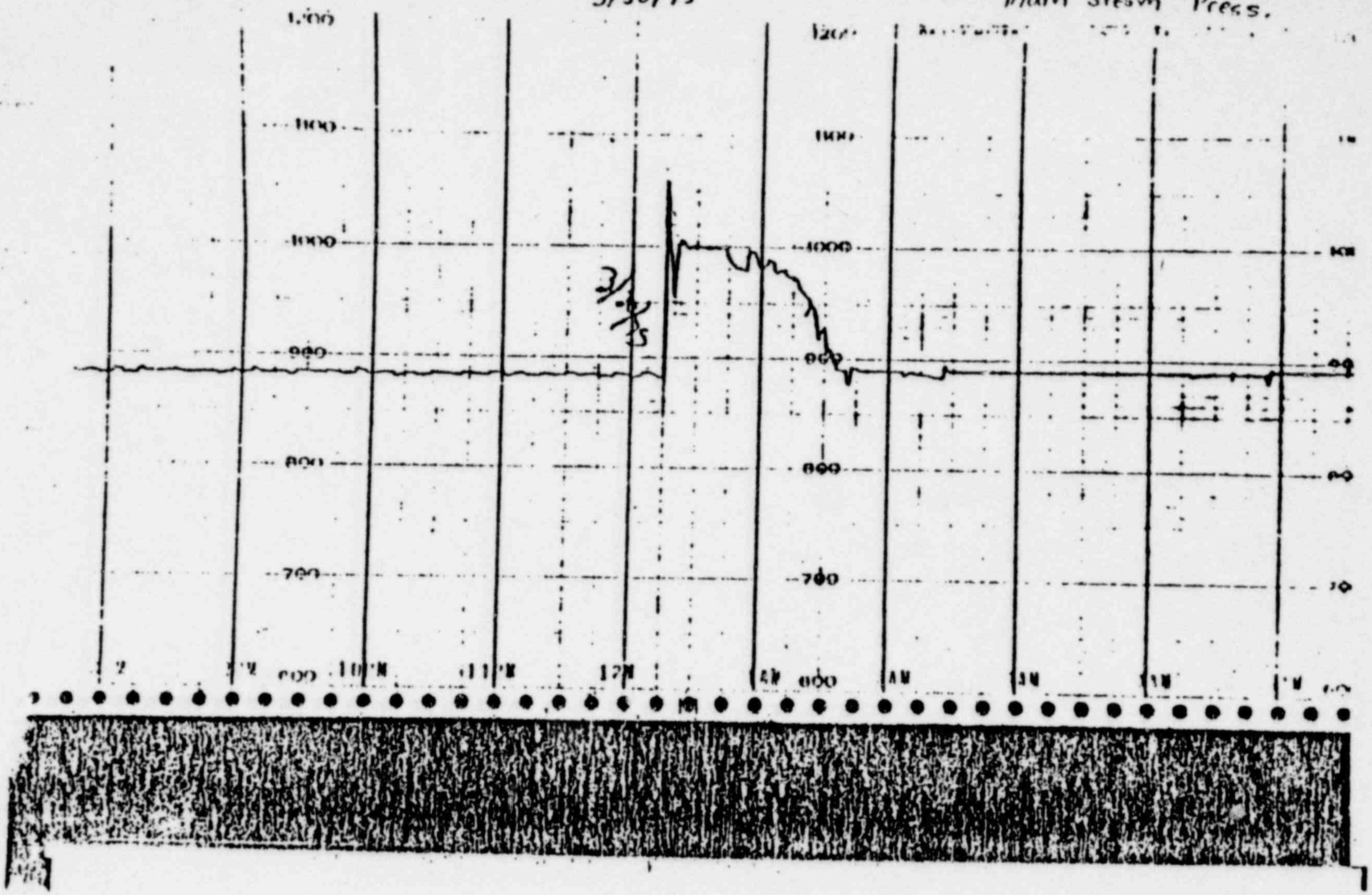
Trip #12 3/30/75 Main Steam Press.



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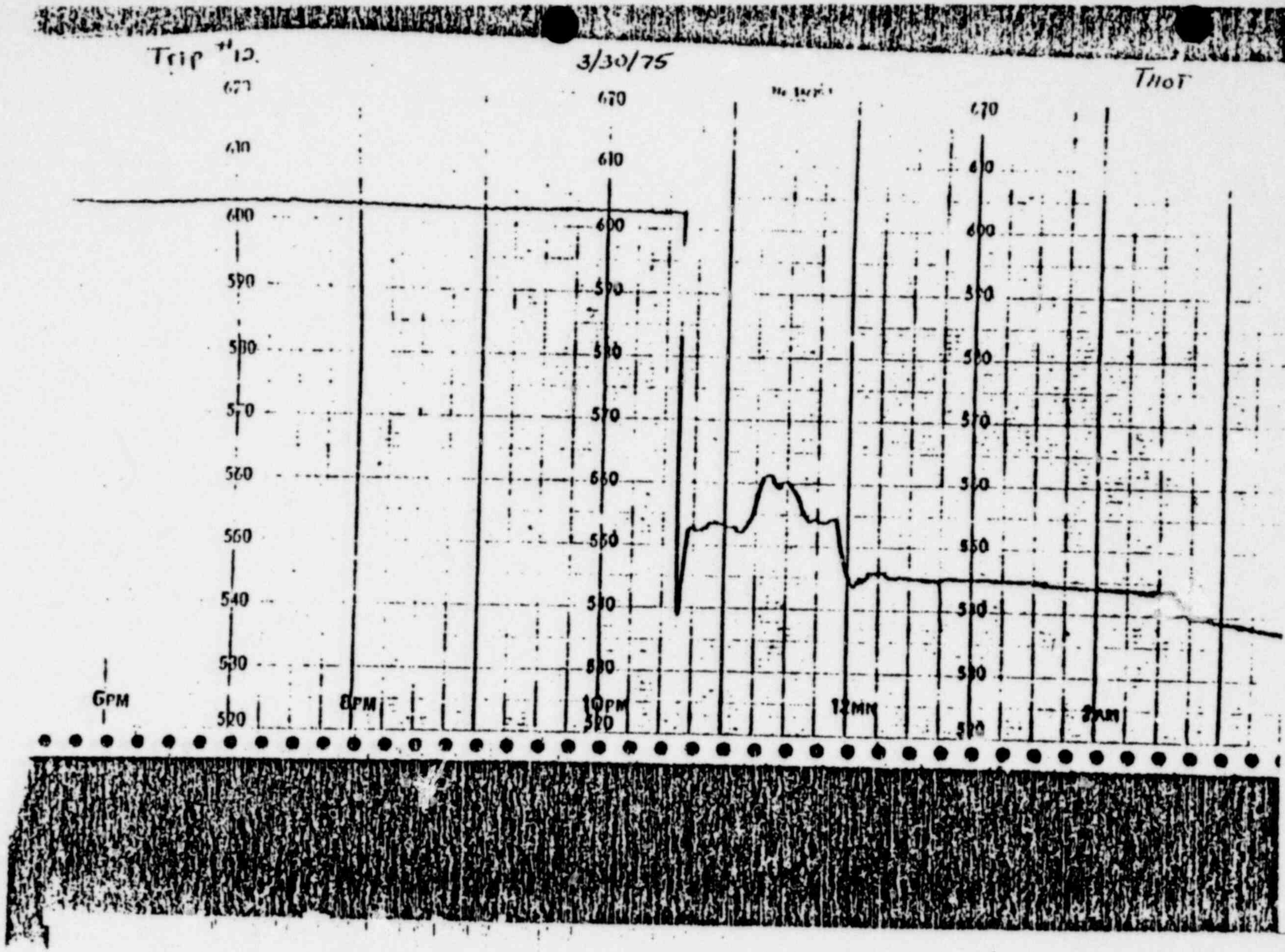

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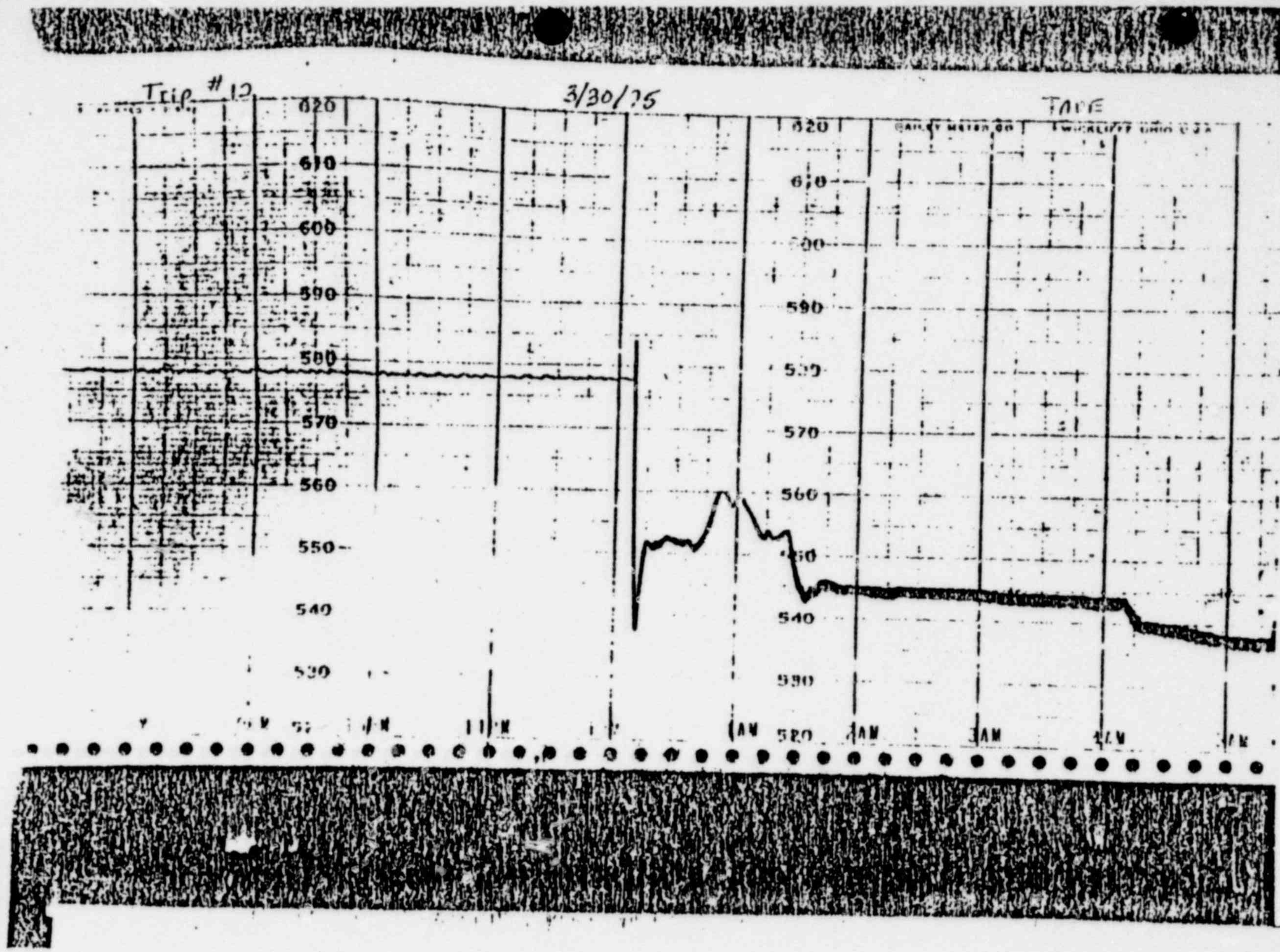

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