U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No. 50-289/90-13 License: DPR-50
50-320/90-06 DPR-73

Licensee: GPU Nuclear Corporation
P. O. Box 480
Middletown, Pennsylvania 17057

Facility: Three Mile Island Nuclear Station, Units 1 and 2

Location: Middletown, Pennsylvania

Dates: June 27, 1990 - August 6, 1990

Inspectors: F. Young, Senior Resident Inspector
D. Johnson, Resident Inspector
T. Moslak, Resident Inspector
D. Beaulieu, Resident Inspector
J. Trapp, Reactor Engineer

Approved by: W. H. Ruland 9/10/90
W. Ruland, Chief Date
Reactor Projects Section No. 4B

Inspection Summary for Combined for Inspection Report Nos. 50-289/13 and 50-320/06

The NRC staff conducted routine and reactive safety inspections of Unit 1 power operations and Unit 2 cleanup activities. The inspectors reviewed plant operations, maintenance and surveillance, radiological practices, security measures and engineering support activities as they related to plant safety. Licensee action on previous inspection findings was also reviewed.

Results: An overview of inspection findings are in the executive summary.

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*Denotes inspection modules performed

Executive Summary

I. PLANT OPERATIONS

Overall, plant operations were conducted in a safe manner. Control of plant power escalation following adjustment of OTSG level control setpoints was accomplished satisfactorily. A resident inspector found a non-safety alternate emergency feedpump supply valve incorrectly deenergized. The valve indication is on the front center control room panel and was left deenergized for at least one week. The operators did not carefully question the aberrant indication during board walkdowns.

II. RADIOLOGICAL CONTROLS

Routine observations of radiological controls were conducted throughout the inspection period. No noteworthy observations were made.

III. MAINTENANCE AND SURVEILLANCE

The licensee continues to conduct maintenance and surveillance activities in a safe and timely fashion. An inadvertent full ESF Train "B" actuation occurred was caused by a momentary lapse in operator concentration. The inspectors considered the event an isolated incident. The licensee found that 10% of the mobile crane inspections had not been performed for two years. No material problems with the cranes were found.

A containment integrated leak rate test was observed, and the report reviewed by an inspector. The containment as found condition met the acceptance criteria. The inspector had no concerns.

IV. ENGINEERING AND TECHNICAL SUPPORT

Engineering support to plant activities was appropriate to resolve specific plant problems. In general, good engineering interface with the plant staff continues to be noted. The NRC staff reviewed the safety evaluation (SE) for raising OTSG operating levels. The NRC staff had no concerns with the licensee's evaluation.

V. EMERGENCY PREPAREDNESS (EP)

Routine review of this area identified no noteworthy observations.

VI. SECURITY

Upgrade of the Computer Access Control System (CACS) was inspected. The new system will greatly improve accessibility to information and provide greater reliability. No concerns were identified relating to the design, installation or testing of the system.

VII. SAFETY ASSESSMENT AND QUALITY VERIFICATION

A Licensee Event Report (LER) was reviewed for the ESF actuation. The LER was adequate in describing the event and corrective actions.

DETAILS

1.0 Summary of Facility Activities

1.1 Licensee Activities

The licensee began the reporting period at 93% power. They were limited to 93% power due to Once Through Steam Generator (OTSG) operation near the Integrated Control System high level limit because of OTSG secondary side fouling. After a safety evaluation was written concluding the plant could safely be operated at higher OTSG le ʾs, on July 20, 1990, reactor power was increased to 97%.

1.2 NRC Staff Activities

This inspection assessed the adequacy of licensee activities for reactor safety, safeguards and radiation protection. The inspectors made this assessment by reviewing information on a sampling basis, through actual observation of licensee activities, interviews with licensee personnel, or independent calculation and selective review of applicable documents. Inspections were accomplished on both normal and back shift hours.

NRC staff inspections were generally conducted in accordance with NRC inspection procedures (NIPs). These NIPs are noted under the appropriate section in the Table of Contents to this report.

Back shift inspections were accomplished during the following periods:

Day/Date	Time
July 29, 1990	4:00 p.m. - 6:30 p.m.
July 30, 1990	4:00 p.m. - 6:30 p.m.
July 31, 1990	4:00 p.m. - 9:30 p.m.
August 5, 1990	10:30 a.m. - 2:30 p.m.

1.3 Persons Contacted

*G. Broughton, Operations/Maintenance Director
J. Byrne, Manager, TMI-2 Licensing
*D. County, QA Auditor
R. Harper, Manager, Plant Material
C. Hartman, Manager, Plant Engineering
D. Hassler, Licensing Engineer
*H. Hukill, Vice President and Director
*W. Heysek, Licensing Engineer
G. Kuehn, Site Operations Director, TMI-2
R. Knight, Licensing Engineer

M. Nelson, Manager, Safety Review
J. Paules, Senior Operations Engineer
M. Ross, Plant Operations Director
*J. Shork, Chairman, TMI-2 Plant Review Group
*R. Skillman, Director, Plant Engineering
P. Snyder, Manager, Plant Materiel Assessment
C. Smyth, Manager, Licensing
*J. Stacey, Manager, Security
R. Wells, Licensing Engineer

* Denotes attendance at final exit meeting (see Section 9.2)

2.0 Plant Operations

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted in the following plant areas:

--Control Room	--Control Building
--Auxiliary Building	--Diesel Generator Building
--Switchgear Area	--Yard Areas
--Access Control Points	--Containment Penetration Area
--Protected Area Fence Line	
--Fuel Handling	--Turbine Building

During the inspection, operators were interviewed concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for observed activities. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspector comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted leads control log. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards.

2.2 Engineered Safety Features System Walkdown

On July 25, 1990, the inspector accompanied an auxiliary operator on a walkdown of the Emergency Diesel Generators (EDG) to verify that the EDGs and their support systems were properly aligned to provide emergency power to the plant's engineered safety features. Included in the inspection effort were the fuel oil systems, coolant systems, lube oil systems, and air starting systems. The inspector verified that the most current revisions of controlled operating and surveillance procedures, 1107-3 and 1303-4.16, respectively, were used in the system walkdowns and confirmed that the valve line-ups identified in the operating procedure matched the appropriate plant drawings. The inspector verified that the valves were in their required position and that selected valves were locked as appropriate. Equipment was clean and well maintained. Instrumentation was properly valved in, functioning and calibrated. No significant conditions were identified that could degrade the operability of the equipment.

2.3 Power Escalation Following OTSG Level Control Setpoint Changes

On July 20, 1990, the licensee completed changes for several Once Through Steam Generator (OTSG) control setpoints to enable the plant to operate at higher power levels. The licensee changed the OTSG high level alarm to 97% in the operating range and the Integrated Control System (ICS) high level limit to 98% of operating range level.

Following these changes, the licensee increased reactor power to approximately 97.5% from the previous maximum of approximately 93%. This resulted in OTSG levels of approximately 96% in the "B" OTSG and 84% in the "A" OTSG. The delta T-cold between the loops was maintained at -4.5 degrees F, and the heat sink protection system function for Hi-Hi isolation of main feedwater remained in the "Defeat" mode.

The affect on "post-trip" emergency operating procedures such as "Reactor Trip" and "Excessive Overcooling" were evaluated by the licensee. No changes were necessary. The licensee completed changes to several operating procedures and setpoint procedures prior to the power escalation. The appropriate computer points for additional monitoring of OTSG conditions were noted, and alarm setpoints for tube/shell delta-T and downcomer temperature were reduced to give the operator an earlier warning of OTSG performance degradation.

The inspectors witnessed the power escalation activities and reviewed the operators' training handout dated July 20, 1990. The handout was comprehensive and included appropriate guidance for the operators during normal operation and during potential transient conditions. The evolution was carried out smoothly with no affect on plant safety. The final correlation between power level and OTSG level compared well with predicted values. The inspectors had no safety concerns on licensee performance in this area.

See sections 6.1 and 9.1 for more information

2.4 Alternate Emergency Feedwater Supply Valve Found Deenergized

While performing a routine walkdown of control room panels, the inspector observed that valve CO-V-12, which is required to be energized by OP 1106-2, was deenergized (both open and closed lights were not lit). CO-V-12 is the non-safety suction isolation valve from the hotwell to the Emergency Feedwater pumps. The hotwell is the next source of water used to supply water to the Emergency Feedpumps when the Condensate Storage Tanks (CST) reaches the low-low level alarm.

The inspector addressed his concern to two control room operators (CROs) and a senior reactor operator (SRO). They said the valve was normally deenergized because of a fire protection provision which requires some valves on the control panels to be deenergized to prevent their spurious operation caused by a fire. The SRO reviewed Abnormal Transient Procedure 1210-10, step 2.5, Actions for Low Level alarms on Condensate Storage Tank, and the procedure was written assuming the valve should be energized. The SRO's response was that if CST ever reached a low level there would be plenty of time to shut the breaker.

One week later, the inspector still observed the valve deenergized and addressed his concern to an Operations Engineer. The engineer immediately recognized that the valve should be energized and directed that power supply breaker position be checked. The breaker was found open and was directed to be closed.

A licensee investigation into this matter failed to determine when the breaker was opened. They could only speculate that breaker was opened inadvertently when performing a procedure that opens another breaker in the vicinity of the breaker in question on July 9, 1990. This would have left this valve deenergized for approximately one month. A valve lineup, which checks the position of CO-V-12 from the control panel, was performed on February 19, 1990. This is the last definitive time the valve position was checked. The valve was not on the Engineered Safeguards Actuation System (ESAS) checklist which verifies safety system lineups each shift.

The licensee feels the cause of this problem is that some valves are required to be deenergized because of the fire protection provision and this confused the operators. To prevent recurrence of the problem, the licensee is considering labeling all valves that are normally left deenergized.

The actual event has minimal safety significance since the operators would have sufficient time to close the breaker before the CST emptied. The Final Safety Analysis Report states that there would be at least 50 minutes of pumpable storage at the Emergency Feedwater design flowrate. However, several operators over at least a week had made control board walkdowns and shift turnovers without discovering the problem. The operators improperly monitored the valve's position and provided the inspector with incorrect information. Both errors showed a lack of detailed conduct of control room activities.

The inspector had no other observations.

3.0 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation Work Permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent) and personnel frisking were observed on a sampling basis.

No noteworthy observations were identified.

4.0 Maintenance and Surveillance Observations

4.1 Maintenance Observation

The inspector reviewed selected maintenance activities to assure that:

-- The activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable;

-- required approvals and releases had been obtained prior to commencing work;

-- procedures used for the task were adequate and work was within the skills of the trade;

-- activities were accomplished by qualified personnel;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established where required and observed;

-- functional testing was performed prior to declaring the particular component(s) operable.

-- equipment was verified to be properly returned to service.

Maintenance activities reviewed included:

-- PH-P1A Preventive Maintenance, JO 25957 and 25958 on June 27, 1990

-- COV111 A/B Spring Pack Maintenance, JO 13364/15433 on June 29, 1990

-- Nuclear Service Heat Exchanger NS-C1A Clean and Inspect, JO 21856, on August 3, 1990

No noteworthy observations were identified.

4.2 Surveillance Observation

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, Technical Specifications were satisfied, testing was performed by qualified personnel and test results satisfied acceptance criteria or were properly dispositioned. The following surveillance testing activities were reviewed:

-- Surveillance Procedure (SP) 1303-5.1 "Reactor Building Cooling and Isolation System Logic Channel and Component Test"

-- SP 1303-5.2 "Loading Sequence and Component Test and High Pressure Injection Channel Test"

-- SP 1107-3 "Diesel Generator"

-- SP 1303-4.16 "Emergency Power System"

Except for the inadvertent full ESAS train "B" action described in section 4.3, no concerns were identified.

4.3 Inadvertent ESAS Train "B" Full Actuation

On July 2, 1990, the licensee was performing Surveillance Procedure 1303-5.1 which is an integrated test of the Engineered Safeguard Actuation System (ESAS) for the reactor building cooling and isolation system logic channels.

The components in the ESAS system are divided into three test groups for each actuation in each train to permit testing of one test group at a time during normal operations. To test only one test group, the operator must depress and hold in place a test button to prevent actuation of the other test groups' components. During performance of step 8.22, which tests Train "B" test group 1 ESAS components, the operator momentarily relaxed his finger holding the test button which caused a full actuation of ESAS Train "B" components. The operator immediately realized his error and responded to secure and restore affected components.

The effect on the plant was as follows: Make-up pump "C" started and caused an injection of approximately 375 gallons of water from the Borated Water Storage Tank (BWST) into the RCS; makeup and purification system letdown was isolated; Diesel generator "B" started but did not load; reactor building emergency cooling river water pump started and filled the reactor building cooling coils with river water; normal reactor building cooling was isolated; the sodium hydroxide (Na-OH) isolation valve to the decay heat system suction header opened but no transfer of Na-OH occurred (verified by sample); and decay heat pump "B" started and ran on minimum recirculation. The plant experienced a minor pressure and power transient due to the injection and isolation of letdown. The relatively small differential boron concentration between the BWST and the RCS helped minimize the transient.

The licensee properly notified the NRC after the event occurred and documented the event in Incident Report Number 1-90-02 on July 3, 1990. The licensee concluded that the event was clearly the result of operator error and that the surveillance procedure was clear, concise and well formatted. Corrective actions listed in the report included having each Shift Supervisor review the incident with his crew, emphasizing the need for total concentration while performing test steps and to have Plant Engineering determine whether design changes in the method of testing is warranted.

The NRC inspector witnessed performance of this surveillance before and after the event and reviewed the incident report. Prior to the event, during observations of the the step that tested train "A", Test group 1 components, the inspector determined that the test was being conducted in a controlled and orderly fashion and had no problems with the test method. After the event, the inspector witnessed the reperformance of the step that caused the event which was accomplished without error. The inspector reviewed the surveillance procedure to ensure that the event did not occur as a result of an unclear procedure. A caution statement clearly states that premature release of the test push button would result in an inadvertent actuation of High Pressure Injection components. Upon review of the incident report, the inspector concluded that the report was accurate and comprehensive and adequately addressed the concerns the inspector had.

The inspector concluded that the licensee responded in a safe and timely manner to the event and that corrective action was adequate. The inspector had no safety concerns associated with this event.

4.4 <u>Reactor Building Integrated Leak Rate Test</u>

An "As found" Type-A, Containment Integrated Leak Rate Test (CILRT) was conducted at the beginning of the 8R refueling outage. This test was performed to demonstrate that the Reactor Building's measured leak rate was less than 0.075 weight percent of the Reactor Building atmosphere per day at a calculated design basis accident pressure of 50.6 psig. The licensee took three attempts at this test to get an acceptable leak rate.

On January 10, 1990, the first of the CILRTs was commenced. Early in the test, test results indicated the leak rate would exceed acceptance criteria. The licensee identified the source of excessive leakage as being into the Once Through Steam Generators (OTSG). The leakage was identified by local inspection of secondary side valves outside containment and by a reduction in inventory in the OTSGs. The licensee identified leakage at the following valves: EF-V57, EF-V58, FW-V7A/B, FW-V16A/B and MS-V70D. To reduce the leakage into the OTSGs, valve packing was tightened, valves were repositioned and OTSG pressure was increased from 30 psig to 45 psig. Since the valves were not part of the test envelope, i.e. not containment isolation valves, no corrections to the CILRT acceptance criteria for known local leak rates was required. Following these actions, the measured containment leak rate was less but still did not meet acceptance criteria. Based on a preliminary test result evaluation, the test was ruled a failure and appropriate notifications were made to the NRC. Further evaluation of the leakage source by the licensee verified that the measured leakage was caused by secondary valve leakage, and therefore the CILRT would later be ruled an as found pass by the licensee.

On January 11, 1990, a second CILRT was commenced. Results of this test were inconclusive due to large temperature changes in containment air temperature. The changes in containment air temperature were caused by a Reactor Building Industrial Cooler. The Reactor Building Industrial Cooler was in service, in accordance with the CILRT procedure, to maintain containment temperature. During this CILRT, a weather front caused a large reduction in ambient temperature which was transferred by the Industrial Cooler into a large drop in containment temperature. Recognizing this, the test personnel secured the Industrial Cooler in an attempt to stabilize containment temperature. The attempt to stabilize temperature failed and the test was terminated.

The third test was commenced on January 12, 1990. During this test, the OTSG pressure was maintained at approximately 45 psig. The results of this test indicated a containment leak rate Upper Confidence Level (UCL), including corrections for local leak rate tests, of 0.0132 weight percent/day. This is an acceptable leak rate based on a leakage limit is 0.075 weight percent/day.

The licensee presented the results of the Type-A, CILRT, on January 25, 1990, to NRC representatives onsite. At this meeting a discussion was held regarding the pressurization of the OTSGs to 45 psi to eliminate leakage through the secondary side systems. The licensee stated that pressurization of the OTSGs was acceptable since the OTSGs would maintain a pressure greater than 45 psig during a Design Basis Loss OF Coolant Accident (LOCA). The licensee was requested to provide documentation verifying that OTSG pressure would remain above containment pressure. This documentation was provided to and reviewed by the NRC. The NRC found the licensee's actions taken with regard to this issue acceptable.

The inspector also reviewed the licensee's January, 1990, CILRT results documented in accordance with 10 CFR 50, Appendix J, Paragraph V.B. These results were summarized in a technical document entitled "Reactor Containment Building Integrated Leak Rate Test, 8R" and were attached to the licensee's letter dated April 16, 1990, to the NRC. The report contains a test summary and general test description, presentation of test results, and data analysis techniques. The inspector verified that the measured containment leak rate met its acceptance criteria and that the test had been conducted in accordance with regulations.

5.0 Security

5.1 Routine Security Evaluations

Implementation of the Physical Security Plan was observed in various plant areas:

-- Protected Area and Vital Area barriers were well maintained and not compromised;

-- Isolation zones were clear;

-- Personnel and vehicles entering and packages being delivered to the Protected Area were properly searched and access control was in accordance with approved licensee procedures;

-- Persons granted access to the site received badges to indicate whether they have unescorted access or escorted authorization;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized;

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate illumination was maintained.

No notable observations were identified.

5.2 Upgrade of Computer Access Control System

The licensee is in the process of replacing the existing Computer Access Control System (CACS) with a system that will provide improved reliability and increased speed for information retrieval. The CACS controls and records access of authorized personnel into the protected area of the plant. The new CACS is currently being installed and is expected to be completed in August, 1990. The licensee has found no problems with the operation of the portions of the system that have been placed in service.

The inspector reviewed the specifications for the upgraded CACS to ensure that the system still fulfills the requirements of 10 CFR 73.55 and 10 CFR 73.70. The inspector verified that personnel manning the Central Alarm Station (CAS) and Secondary Alarm Station (SAS) have been properly trained on the new equipment and that instructions have been posted on the operation of the new card readers. Installation and testing of portions of the new system was observed to verify adequacy.

The inspector identified no significant concerns relating to the design, installation or testing of the system. The system will greatly improve accessibility to information and provide greater reliability.

6.0 Engineering and Technical Support

6.1 OTSG Level Change Safety Evaluation

As part of the licensee plan to increase Once Through Steam Generators (OTSG) operating water level, the licensee completed a safety evaluation and 10 CFR 50.59 review for raising the OTSG high level limit. This safety evaluation, number SE-TI115403-005, Rev. 0, was reviewed by the inspector for completeness and accuracy.

The safety evaluation (SE) showed that increasing downcomer level would not invalidate safety analysis assumptions concerning OTSG inventory, and demonstrated that loss of feedwater heating would not adversely affect safe plant operations.

The evaluation considered the affect on operation by reduction in feedwater heating and operation with the OTSG high level isolation of main feedwater bypassed. The safety evaluation also addressed the Departure From Nucleate Boiling Ratio (DNBR) transient, containment overpressurization, offsite dose consequences and tube loading. None of these Final Safety Analysis Report (FSAR) analyses were affected by the small change in OTSG inventory which would result from operating at higher levels.

The plant response to the June 22, 1990, test was also documented. The test results showed no appreciable affect from the increased inventory, resulting from higher operating levels.

The SE concluded that operation with a full downcomer would not violate Technical Specifications or Design Basis Accident (DBA) assumptions and that loss of feedwater preheating would not adversely affect plant operation. The evaluation concluded that operation up to 98% level was acceptable for up to four effective full power years as long as the upper downcomer temperature remains greater than 526 degrees F on the "B" OTSG and 528 degrees F on the "A" OTSG. This difference in feedwater temperature was due to the imbalanced feedwater flow.

The NRC staff concluded that the SE was a complete review and analysis of potential concerns for raising OTSG operating levels.

The inspectors had no concerns with the licensee's analysis.

7.0 Safety Assessment and Quality Verification

7.1 Review of Written Reports

The inspector reviewed an LER to verify that the details of the event were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated and whether the event warranted onsite followup.

Unit 1:

LER 90-006-00, Inadvertent Emergency Safeguards (ESAS) Actuation Due to Personnel Error. LER issue date was July 31, 1990.

The above LER was reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LER was found to be of high quality with proper characterization of the event, root cause determination and corrective action.

8.0 TMI-2 Mobile Crane Inspection Record Irregularities

The licensee received information that routine monthly inspections for on-site mobile cranes were not appropriately performed. The monthly inspections are performed to determine if there has been a degradation of the crane's hoisting mechanisms. The mobile cranes involved are the 140 ton Manitowoc, a 30 ton crane and three 15 ton cranes. The cranes have been used to lift resin liners. The licensee found that about ten percent of the inspections scheduled over a two year period were not performed. As a result of the investigation, disciplinary action was taken against one individual. Inspections were immediately performed on each of the cranes by outside vendors. The vendor concluded that no degradation had occurred in the cranes' ability to safely lift rated loads. Based on this and that no significant corrective maintenance had occurred over the last two years, the licensee concluded that missed checks did not adversely affect the cranes.

The resident inspector reviewed the results of the licensee's investigation. The inspector determined that the licensee conducted a thorough investigation and took appropriate corrective actions. The inspector concluded that the irregularities identified in conducting crane inspections did not lead to unsafe cranes in this instance.

9.0 Management Meetings

The following meetings were conducted:

9.1 OTSG Level Meeting

At 10:00 a.m. on July 19, 1990, the below listed licensee and NRC staff personnel participated in a meeting to discuss the level changes to be made by the licensee for Once Through Steam Generator (OTSG) operation.

GPU Nuclear Corporation

-- J. Link, Engineer, System Engineering
-- C. Smyth, Manager, TMI-1 Licensing
-- L. Lanese, Manager, Mechanical Systems
-- J. Paules, Lead Operations Engineer
-- R. Barley, Manager, Steam Generator Programs
-- W. Drendall, Engineer, Engineering and Design
-- E. Eisen, Project Engineer, TMI-1
-- R. Skillman, Director, Plant Engineering

USNRC Staff

-- C. Hehl, Director, Division of Reactor Projects
-- D. Johnson, Resident Inspector, TMI-1
-- R. Hernan, Senior Project Manager, NRR
-- F. Rosa, Director, Project Directorate 1-4, NRR
-- A. Cohmeier, Reactor Engineer
-- D. Terao, Chief, Materials and Process Section
-- W. Ruland, Chief, Reactor Projects Section 4B
-- H. Gregg, Senior Reactor Engineer
-- M. Cc̈rmal, Reactor Engineer

Commonwealth of Pennsylvania

-- R. Cook, PWR Group Leader, DER

The meeting was initiated by R. Skillman of the licensee organization, who gave a general overview of OTSG operation and the history of the heat transfer surface fouling problem.

The TMI-1 OTSGs have experienced a phenomena whereby iron oxide deposits from the feedwater/condensate systems have impeded flow through the portion of the steam generator where significant heat transfer and boiling occur. The deposits occur in the broach holes in the tube support plates (TSP) in the lower part of the OTSG, primarily in the 3, 4, 5 and 6th TSPs. Recent mechanical cleaning has removed some material, and a recent manual reactor trip has redistributed some deposits but neither activity was totally successful in allowing the plant to reach full power.

The licensee presented data from a test on June 22, 1990, which showed that OTSG level could be increased above present setpoints with no adverse affect on feedwater heating, which takes place in the OTSG downcomer. A licensee engineer in technical functions briefed the staff on several analyses related to OTSG overfill and concluded that OTSG level control setpoints could be increased without any affect on the safety analysis. The conclusion was that OTSG overfill was not a credible event even with an increased OTSG operational level. The licensee also presented data from OTSG level instrument calibration to show that the level instrumentation was accurate at these high ranges.

The licensee plans were to increase operating level from the present 92 percent in the "B" OTSG to an operational maximum of 96 percent. Reactor power was expected to be increased by approximately 4 percent during this evolution (see section 2.3 of the report).

The meeting concluded with a brief summary by the plant engineering director, who stated that the power escalation would take place the following day.

The NRC staff concluded that the licensee had adequately assessed the potential problems and concerns in operating the OTSG at higher than previously accepted levels. The licensee briefing was comprehensive and the safety evaluation (discussed in Section 6.1) was also adequate. The staff had no safety concerns on the proposed licensee activities.

9.2 Exit Meeting

A summary of inspection findings was further discussed with the licensee at the conclusion of the report period on August 6, 1990. Persons designated with an asterisk in section 1.3 were present at the exit meeting.

TMI-1 OTSG LEVEL VERSUS POWER EXPERIENCE

- CAUSES OF FOULING
- PHYSICAL IMPACT
- THERMOHYDRAULIC IMPACT
  - CYCLE 6
  - CYCLE 7
  - CYCLE 8
- NEED FOR CHANGE

WHAT CAUSES FOULING

- IRON AND DISSOLVED SOLIDS ARE GENERATED IN THE TURBINE CYCLE PIPING AND COMPONENTS AND THE OTSG
- IRON IS TRANSPORTED TO AND DEPOSITED IN OTSG
- DEPOSITS FORM ON THE SUPPORT PLATES AND ON THE TUBES
- TEMPERATURE CHANGES CAUSE DEPOSITS ON TUBES TO SPALL (FLAKE) OFF
- THE BROACHED HOLE OPENING REDUCED BY SUPPORT PLATE FOULING AND FLAKE BLOCKAGE
- INCREASED FLOW PATH RESISTANCE NECESSITATES HIGHER DRIVING FORCES (DOWNCOMER LEVEL)

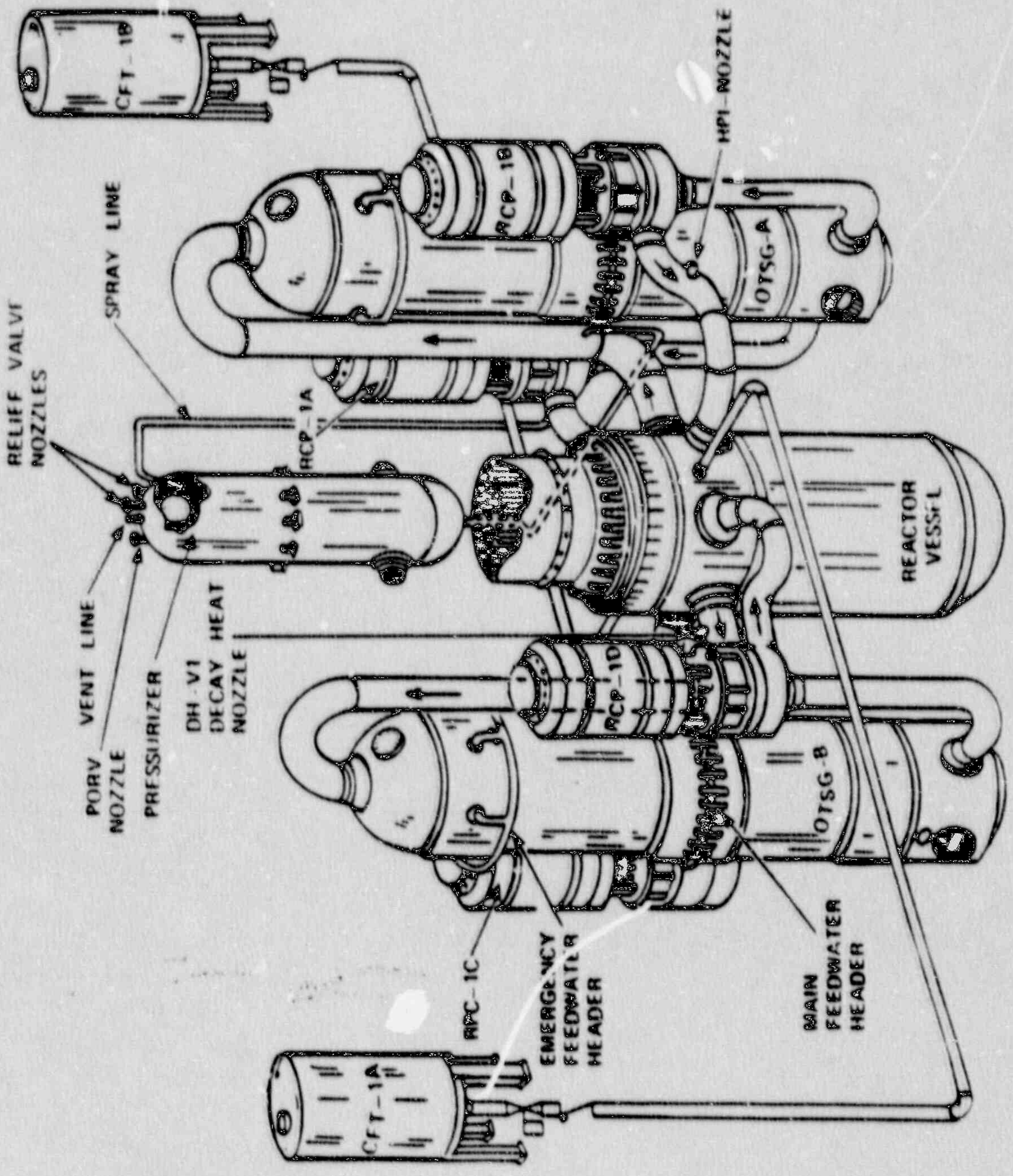
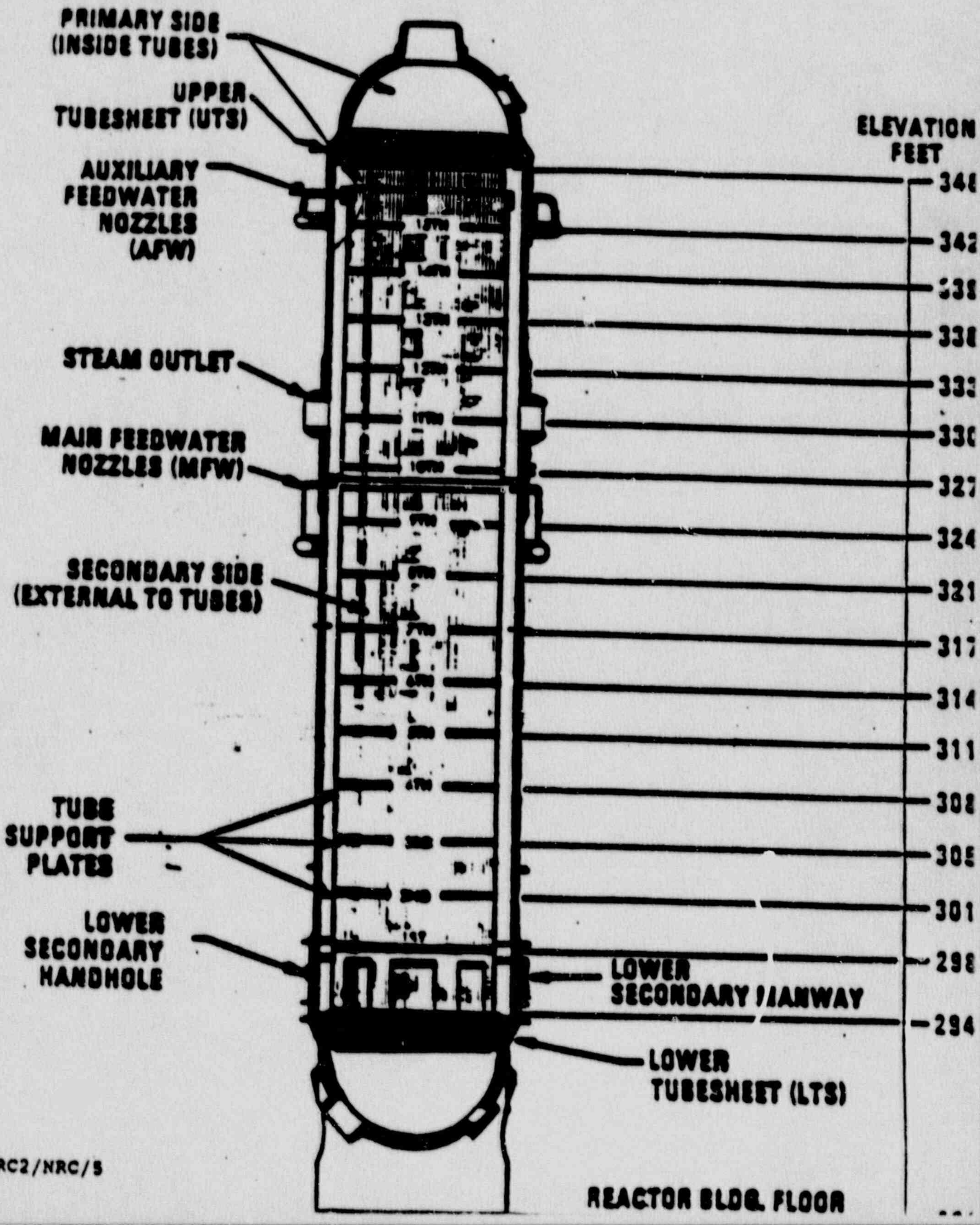


FIGURE-1 REACTOR COOLANT SYSTEM

OTSG Longitudinal Section Elevations (Typ.)



GPU Nuclear

OTSG Tube Support Plates, broached openings for flow between plate and tube

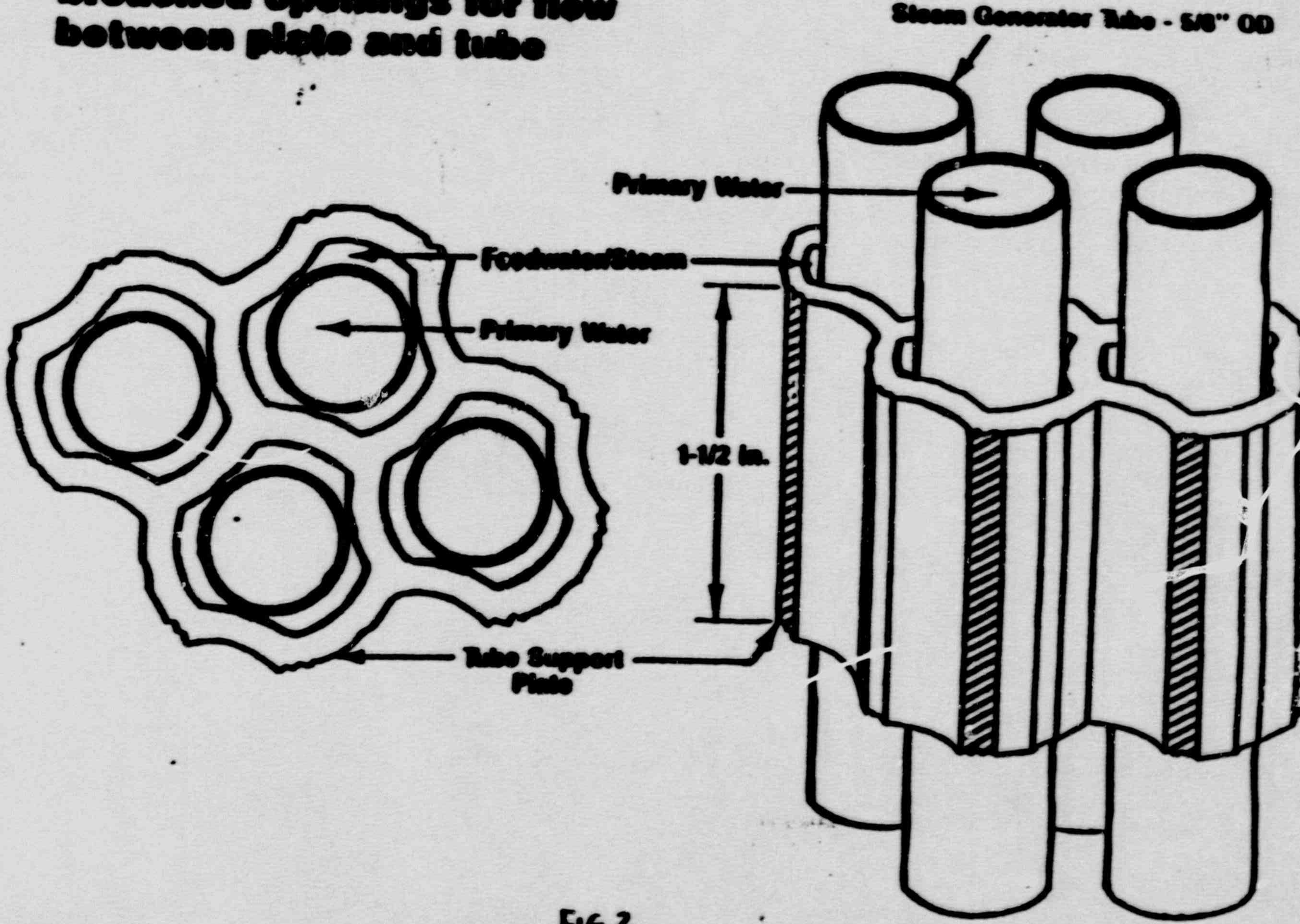
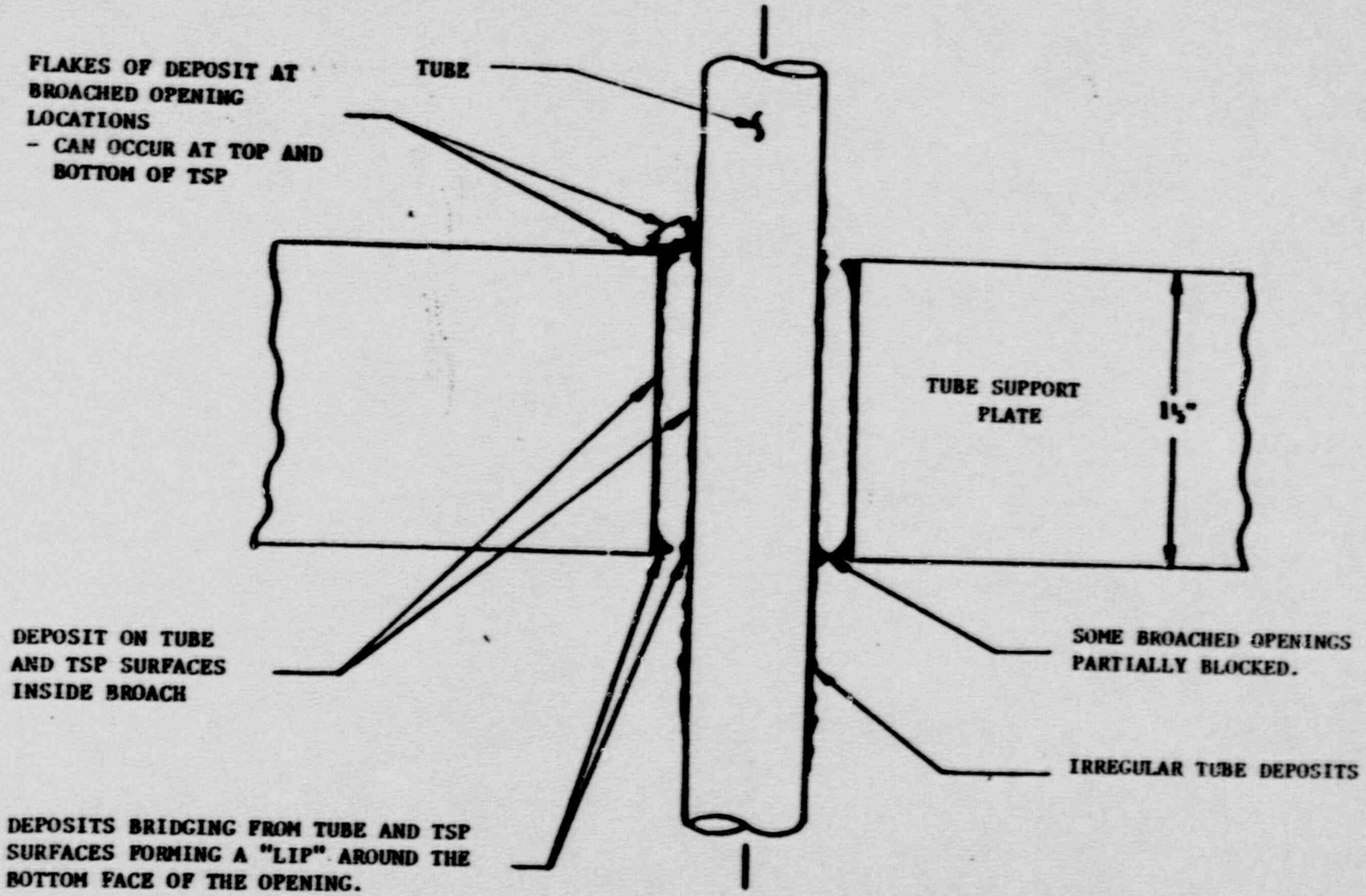
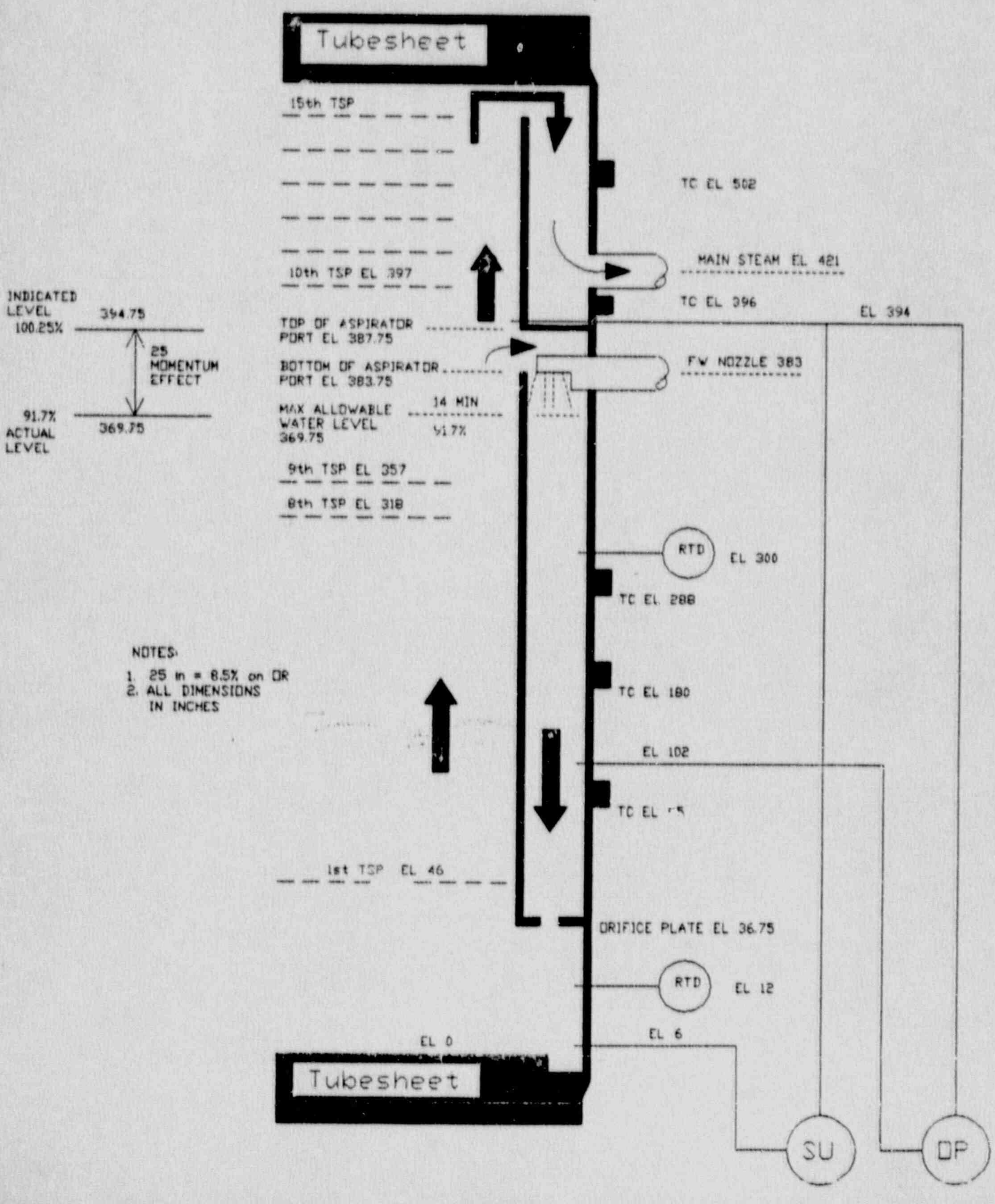


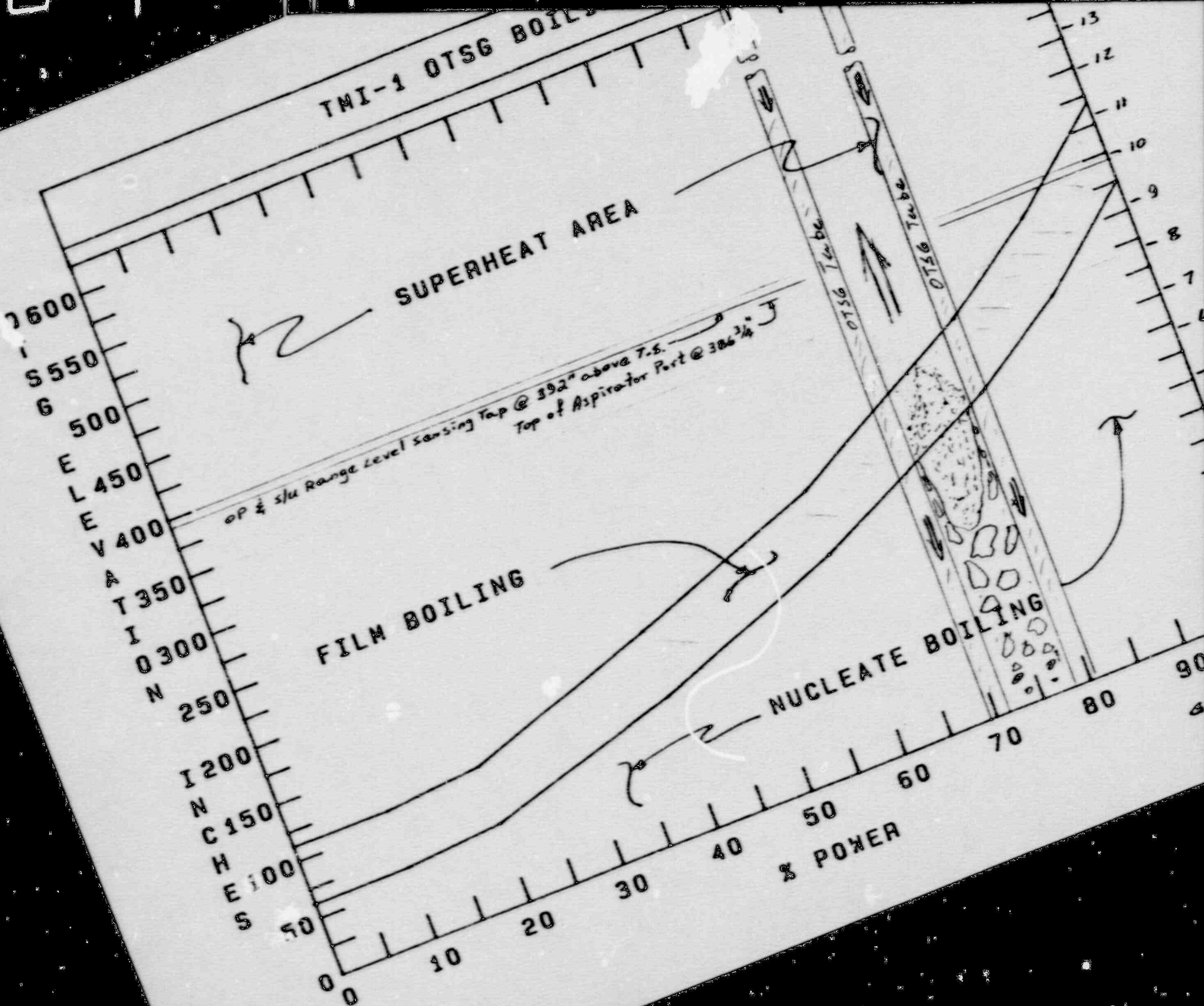
FIG 2

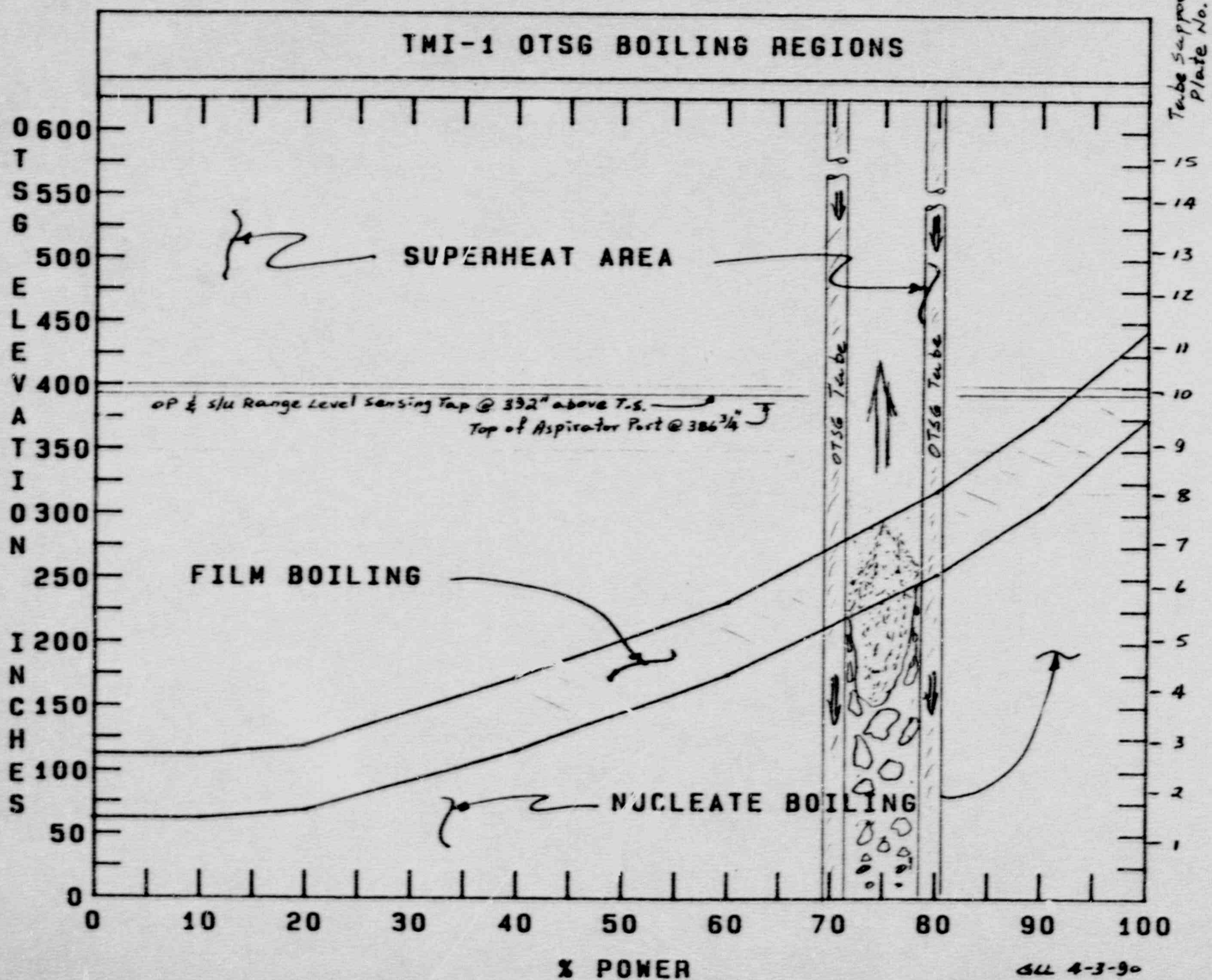


<u>SKETCH OF A TYPICAL TSP BROACHED OPENING</u>

OTSG OPERATE RANGE LEVEL

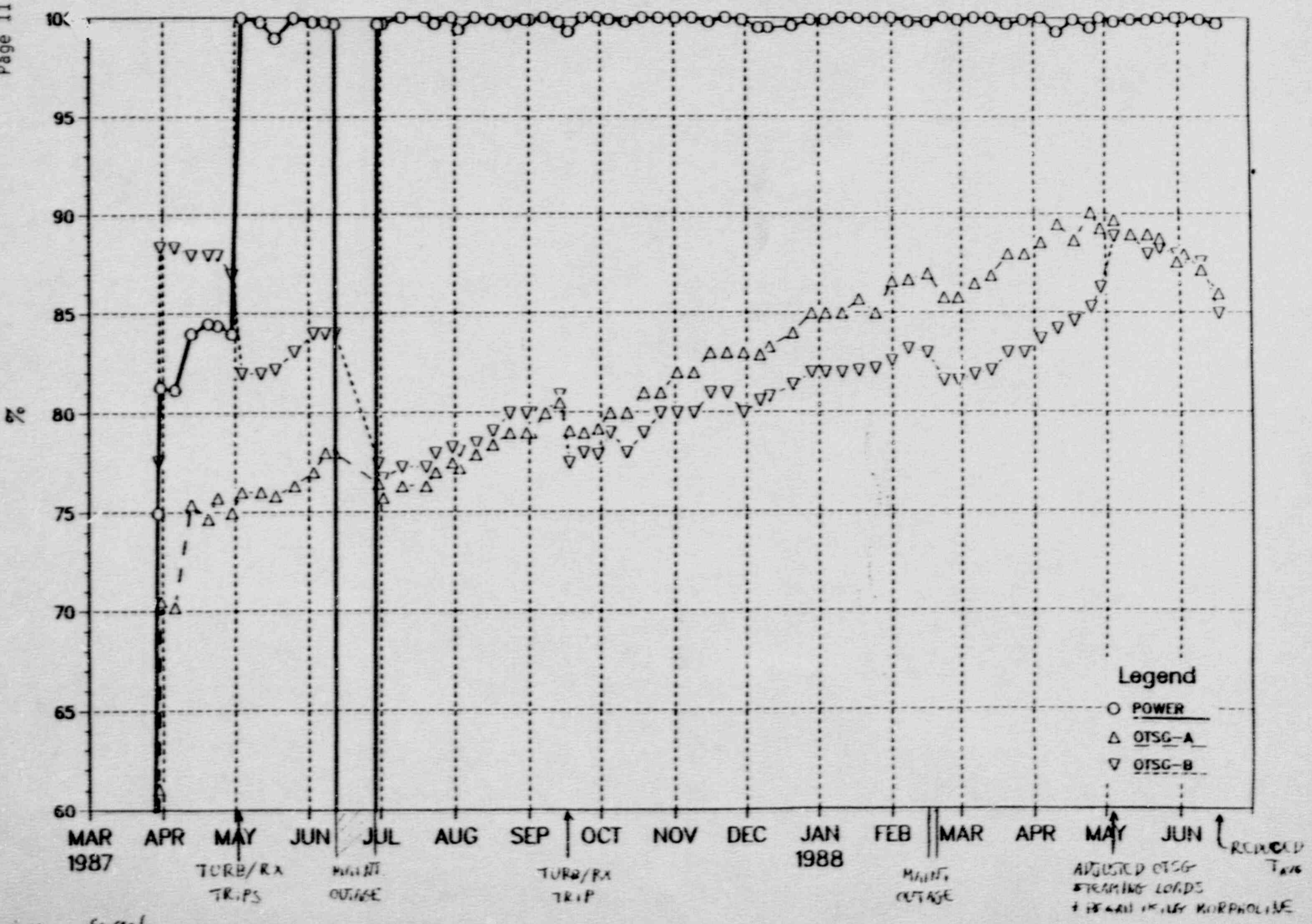



TMI-1 OTSG BOIL
SUPERHEAT AREA
OP & S/U Range Level Sensing Tap @ 392" above T.S.
Top of Aspirator Port @ 386 3/4"
FILM BOILING
NUCLEATE BOILING
OTSG Tube
OTSG Tube
ELEVATION INCHES
% POWER
0
50
100
150
200
250
300
350
400
450
500
550
600
0
10
20
30
40
50
60
70
80
90
13
12
11
10
9
8
7

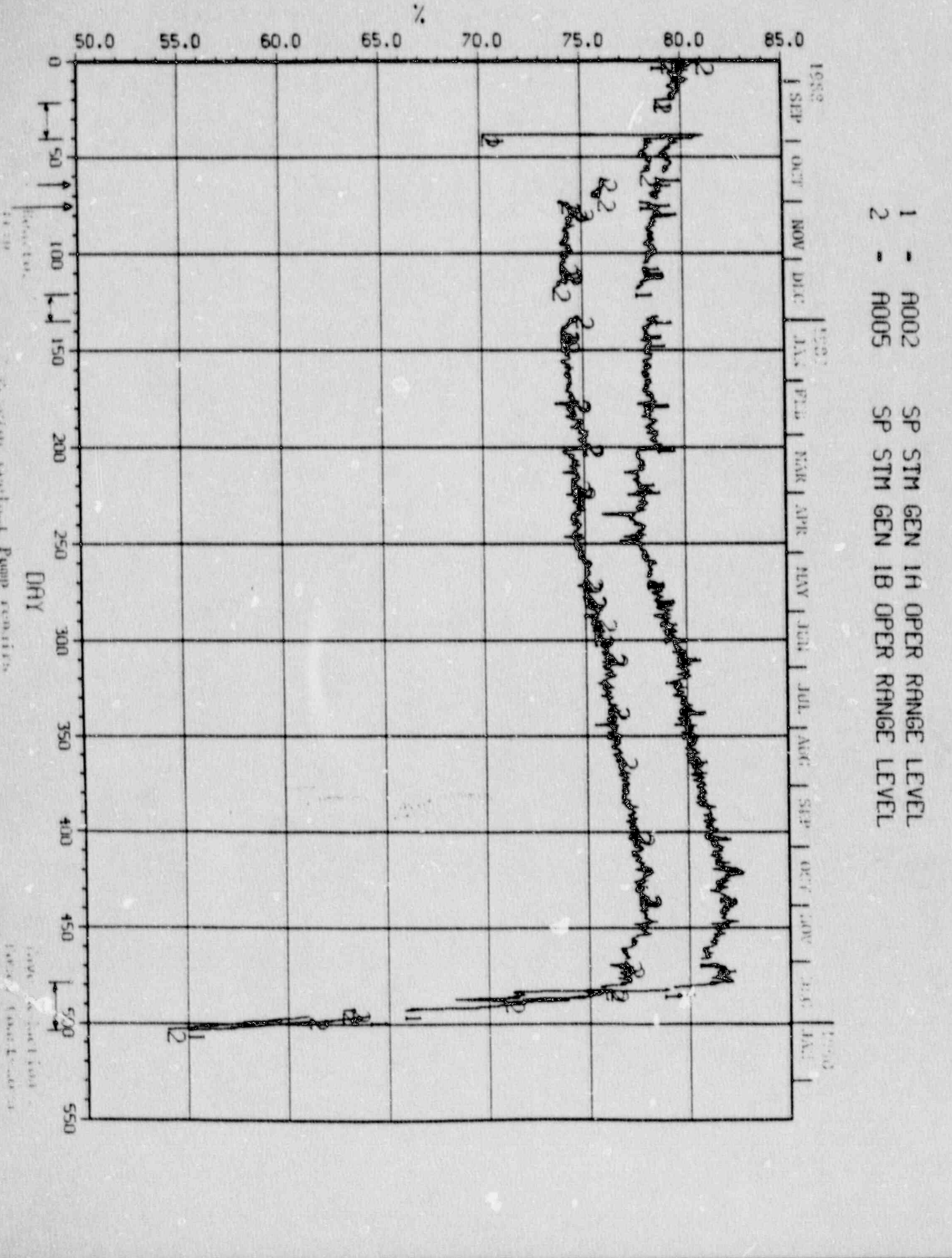

TMI-1 OTSG BOILING REGIONS
OTSG ELEVATION INCHES
0
50
100
150
200
250
300
350
400
450
500
550
600
SUPERHEAT AREA
OP & S/U Range Level Sensing Tap @ 332" above T.S.
Top of Aspirator Port @ 386 3/4"
OTSG Tube
OTSG Tube
FILM BOILING
NUCLEATE BOILING
Tube Support Plate No.
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
0
10
20
30
40
50
60
70
80
90
100
% POWER
GLL 4-3-90

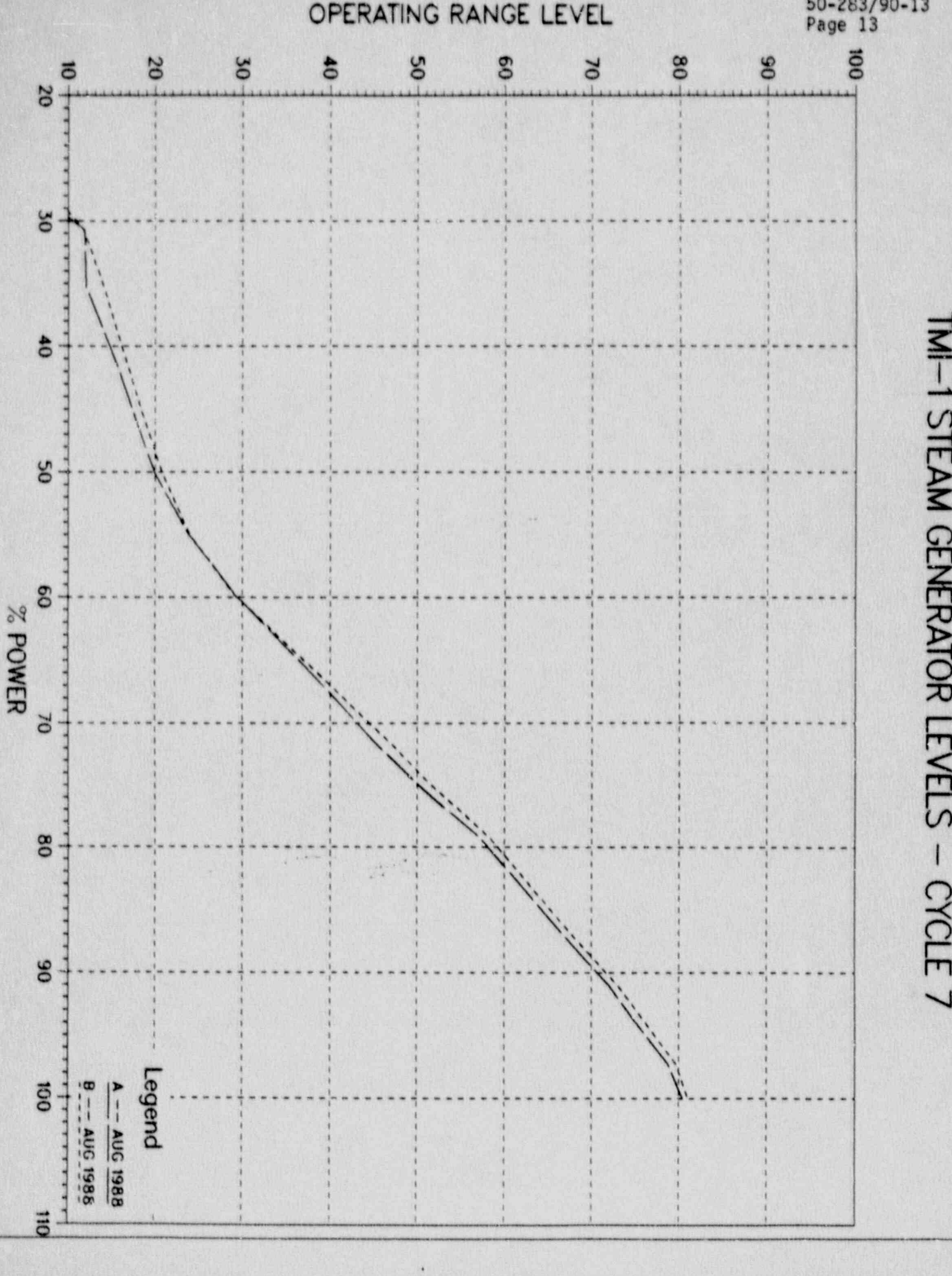
Attachment 1
50-283/90-13
Page 11

TMI-1 STEAM GENERATOR WATER LEVELS



Attachment 1
50-283/90-13
Page 12

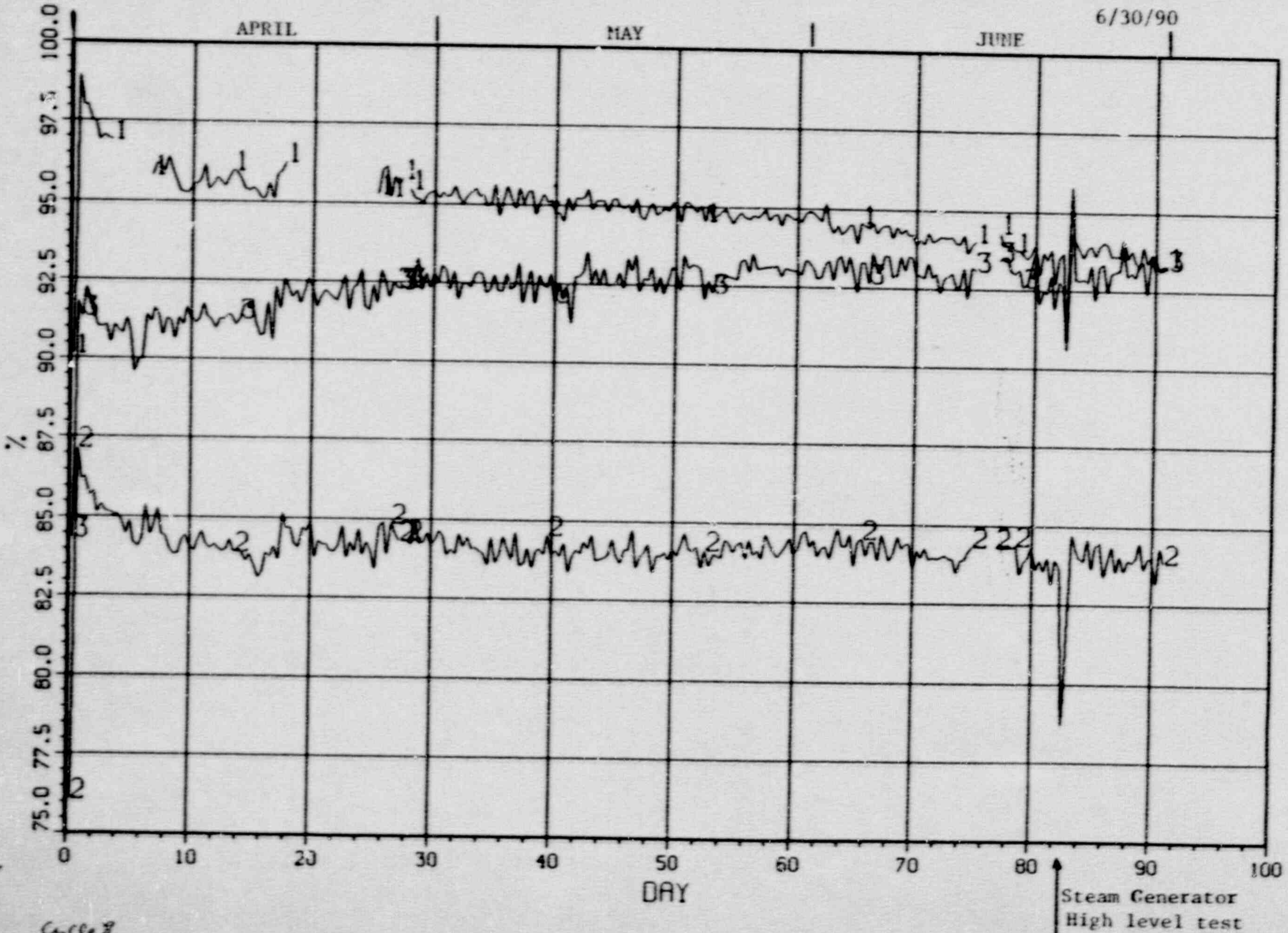



TMI–1 STEAM GENERATOR LEVELS – CYCLE 7
OPERATING RANGE LEVEL
% POWER
10
20
30
40
50
60
70
80
90
100
110
Legend
A -- AUG 1988
B --- AUG 1986

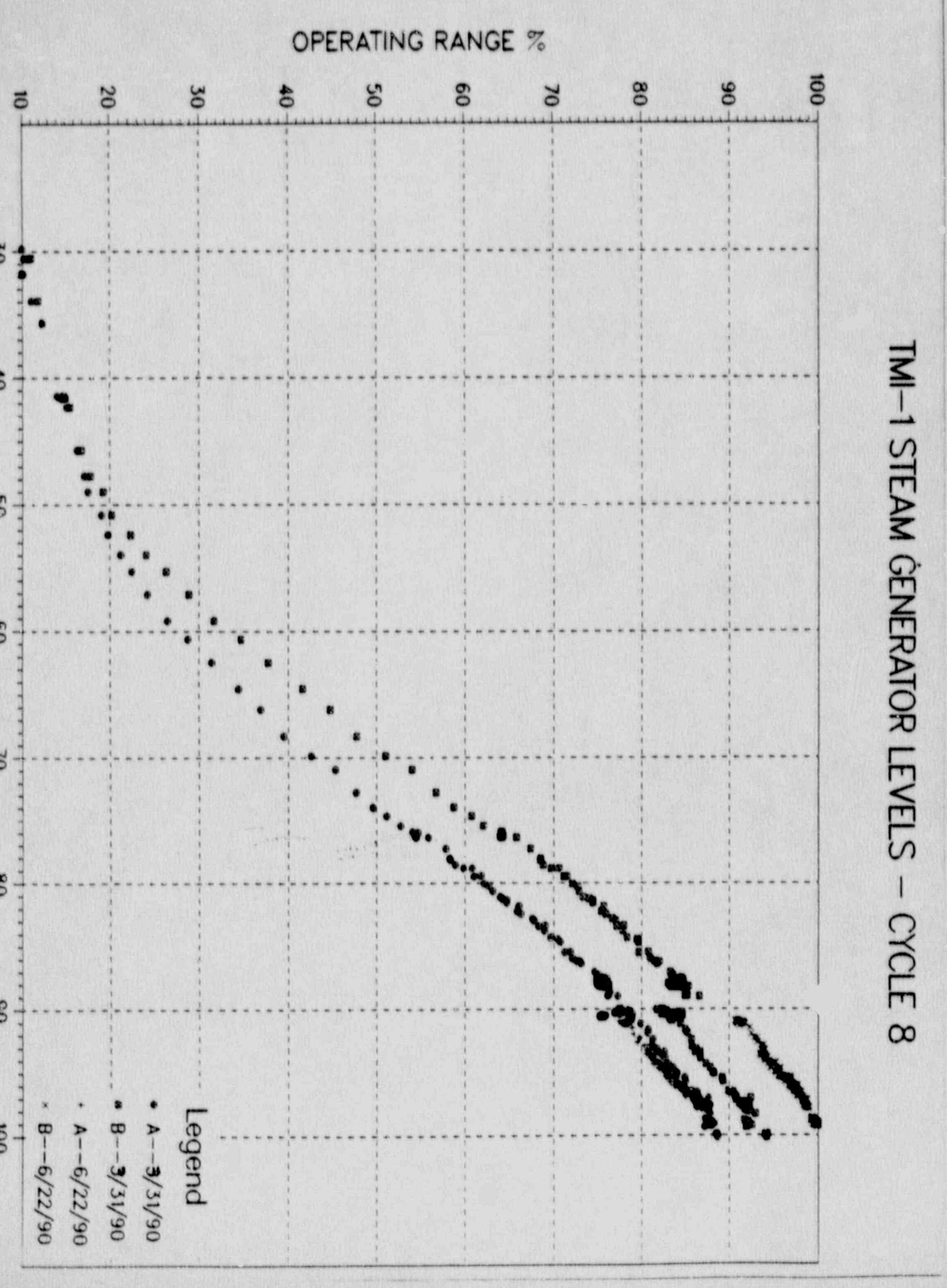
PLANT ANALYSIS DATA - (TMI-1)

1 - C3539 BEST ESTIMATE CORE POWER
2 - A0002 OTSG A OPER LEVEL / ICS INPUT
3 - A0005 OTSG B OPER LEVEL / ICS INPUT

4/ 1/1990
TO



Cycle 8


TMI-1 STEAM GENERATOR LEVELS - CYCLE 8
OPERATING RANGE %
% POWER
Legend
A--3/31/90
B--3/31/90
A--6/22/90
B--6/22/90

ISSUE OF CONCERN

OTSG INVENTORY

ACCIDENT OF CONCERN

STEAM LINE BREAK

- Tube Bundle Inventory Assumed Fouled Heat Transfer Surfaces

  OTSG Tube Heat Transfer is not Reduced as a Result of the Type of Fouling in the OTSGs

  Tube Bundle Inventory is Less Than Assumed

- Downcomer is Assumed Full of Saturated Water (Maximizes Inventory)

- TMI-1 OTSG Inventory Less Than Assumed in Analyses

- Steam Line Break Analyses are not Impacted

OTSG OPERATE RANGE LEVEL VERIFICATION TEST

PURPOSE: Determine the maximum downcomer level for operation without flooding the feedwater nozzles.

METHOD: Slowly raise Unit Load (thus downcomer level) while monitoring for a significant reduction in feedwater preheating caused by flooding the nozzles.

TERMINATION:
100% Reactor Power
10F Decrease in Downcomer Temperature
35F Minimum Steam Superheat
> 0.25F T-cold Decrease per 1% Power Increase
Tube to Shell Compressive Limit Approached
Anomalous Condition(s)

PREREQUISITES:
Operate Range Level Instrumentation Calibrated
ICS High Level Limit Disabled
HSPS High Level Feedwater Isolation Defeated
Level Transmitter dP Routed to Plant Computer
Parameters of Concern Trending Initiated
Plant Computer Data Collection Initiated
Operating Shift Augmented
Crew Training/Briefing Completed
Auxiliary Boilers Operable/Hot Standby

OTSG OPERATE RANGE LEVEL VERIFICATION TEST

PRETEST CONDITIONS:

Reactor Power	94%
"A" Operate Range Level	82%
"B" Operate Range Level	93%
T_{cold} "A" - T_{cold} "B"	-4.5F

TEST PROGRESSION: PHASE 1

Reduced Unit Load to Achieve 90% Reactor Power

Equalized SG Heat Load by Restoring Cold Leg Temperature Difference to Zero (Balanced Feedwater Flow)

Raised Unit Load until 100% Reactor Power was Reached

Lowered Unit Load to Achieve 96% Reactor Power

OTSG OPERATE RANGE LEVEL VERIFICATION TEST

TEST PROGRESSION: PHASE 2

Initial Conditions Same as End of Phase 1

Reratioed Feedwater to Increase "B" OTSG Downcomer Level (+4.0°F Cold Leg Temperature Difference)

Raised Unit Load Until 100% Reactor Power was Reached

Lowered Unit Load to Achieve 93% Reactor Power

Reratioed Feedwater to Minimize "B" OTSG Downcomer Level (-4.5°F Cold Leg Temperature Difference)

POSTTEST CONDITIONS:

Reactor Power	94%
"A" Operate Range Level	82%
"B" Operate Range Level	93%
Delta T-cold	-4.5F

OTSG OPERATE RANGE LEVEL VERIFICATION TEST RESULTS

- Downcomer Temperature Decreased 5F During Power Escalation from 90% - 100%

- Downcomer Level Increased from 90 - 100% OR During the Test

- Change in Downcomer Temperature was NOT Proportional to Change in Operate Range Level

- Reduction in Feedwater Heating Occurred Above Approximately 95% Operate Range Level

- Encroachment of the Mixing Volume May Have Occurred Above Approximately 99% Operate Range Level (Downcomer Temperature vs. Operate Range Level Plot Slope Increased)

- Plant Exhibited Normal Stability Throughout the Test

OPERATIONAL CONCERNS DURING PLANT UPSETS WHEN OPERATING WITH INCREASED LEVELS

- Feedwater Nozzle Flooding is NOT an Unidentified Transient
- Nozzle Flooding Transient can Occur from any initial OR Level
- Slow Transient and a Reactor Trip is not Expected
- If the Reactor Trips Normal Post Trip Response is Expected
- Operator Response Time to Post Trip Overfill Event has not Significantly Changed
- Tube Compressive Loads during Loss of Feedwater Preheating are Within Limits

CONCLUSION

1. Operating TMI-1 with a downcomer full of saturated water does not violate Tech Specs or Design Bases Analysis assumptions and is not a safety risk.

2. Loss of Feedwater Preheating during a plant upset will not adversely affect plant safety or safe plant operation.

3. The plant exhibited normal stability at 100% OR level during the testing. Based on these results a high level limit of 98% OR is justified.

- In Addition -

4. The real downcomer level is below the indicated OR level principally due to the momentum effect.

5. The conclusions about feedwater momentum must be reevaluated several years in the future based on feedwater nozzle wear.

6. OTSG level can be maintained at a constant value with a decrease in power resulting from increased tube fouling as long as upper downcomer temperatures remain greater than specified values.