U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No.	50-289/85-30		
Docket No.	50-289		
License No.	DPR-50	Priority --	Category C

Licensee: GPU Nuclear Corporation
Post Office Box 480
Middletown, Pennsylvania 17057

Facility At: Three Mile Island Nuclear Station, Unit No. 1

Inspection At: Middletown, Pennsylvania

Inspection Conducted: December 13, 1985 - January 10, 1986

Inspectors:
W. Baunack, Project Engineer, Region I
N. Blumberg, Lead Reactor Engineer, Region I
L. Briggs, Lead Reactor Engineer, Region I
J. Bryant, Senior Resident Inspector (Oconee), Region II
P. Eapen, Chief, Quality Assurance Section, Region I
D. Haverkamp, Technical Assistant for TMI-1 Restart, Region I
W. Oliveira, Reactor Engineer, Region I
D. Trimble, Resident Inspector (Calvert Cliffs) Region I
R. Urban, Reactor Engineer, Region I
A. Weadock, Radiation Specialist, Region I
P. Wen, Reactor Engineer, Region I
J. White, Senior Radiation Specialist, Region I
F. Young, Resident Inspector (TMI-1), Region I

Other NRC Personnel: J. Thoma, Project Manager, Office of Nuclear Reactor Regulation

Contractor Personnel: B. Gore, Senior Research Scientist, Battelle Pacific Northwest Laboratories

Approved By: [signature] for R. Conte, TMI-1 Restart Manager, TMI-1 Restart Staff, Division of Reactor Projects — 2/12/86 Date

Inspection Summary:

The TMI-1 Restart Staff conducted routine and special (NRC shift coverage) safety inspections (888 hours) of power operation focusing on operator and

management performance. Specifically, items reviewed in more detail in the facility operations area were: control of fire doors; power operated relief valve test results; pressure switch malfunction for makeup pump lube oil sub-system, diesel generator standby coolant system; letdown cooler leakage; out-of-specification log entries; instrumentation monitoring; and annunciator black board conditions. Special focus continued on the completion of the power escalation testing program, the radiation protection program as applied to power escalation, and the non-licensed training program. Other review items included: reactor trip event and post-trip review; radiological release events; emergency feedwater pump operability; licensee readiness for continued power operations; steam generator cleaning technique; and licensee action on previous inspection findings.

Inspection Results:

Licensee management and the quality assurance department continued their presence and involvement in daily activities. Problems were noted in the thoroughness and completeness of management and technical support personnel review of plant problems. The problem of workers in the spaces having the potential to cause safety system challenges persisted. Apparently the licensee's corrective actions are not yet understood by all workers. The licensee continued to be aggressive in the maintenance of safety-related equipment.

Operators continued to conduct themselves in a competent manner and their actions reflected a strong performance-oriented training program. Accordingly, operators were responsive to radiological events and plant trips that occurred during this period. A poor operational practice was noted of "living with" out-of-specification readings; although operator log-keeping actions were appropriate, it appeared that mid-level managers were unresponsive in taking corrective actions. No performance problems were identified in the review of non-licensed operator training. Overall, procedures were properly implemented, but individual procedure step inadequacies continued to be observed. The labeling on fire doors was confusing. An improperly coordinated surveillance procedure change with respect to daily functional checks of fire doors resulted in an apparent violation of technical specifications (paragraph 3.2.2).

The startup test program was effective in identifying system interface problems and in providing training for plant operators along with confirming proper plant performance.

The Radiation Protection Program remained strong in support of licensee work activities during the power operation mode. Personnel inattentiveness was the cause for radiation area signs being left down; and, as a result in one case, an individual entered a high radiation area without knowing it. No overexposure occurred.

The licensee was responsive and took appropriate corrective action for NRC staff findings from previous inspections.

The return to commercial power operations was conducted in a deliberate and conservative manner.

DETAILS

1. Introduction and Overview

1.1 General

At the beginning of this inspection period on December 13, 1985, the TMI-1 Restart Staff was providing on-shift inspection coverage 12 hours a day to assess restart operating activities. At 3:00 a.m. on December 27, 1985, continuous coverage was initiated for the power escalation to the maximum achievable power testing plateau, and at 6:00 p.m. on that day this inspection coverage was returned to 12 hours a day consistent with the reduced level of testing activity and steady-state facility operation.

On both Christmas and New Year's Day periodic inspection coverage was provided by the resident inspectors. At 7:00 a.m. on January 2, 1986, continuous coverage was again initiated for a planned reactor trip test from maximum achievable power and the subsequent plant restart. Shift coverage was terminated at 7:00 a.m. on January 5, 1986, following the return to steady-state plant operation at 90% of rated power, marking the completion of the restart test program. As of 8:00 a.m. on January 10, 1986, the TMI-1 Restart Staff organization was secured and TMI-1 inspection responsibility was returned to the normal Region I organization alignment.

The staff's on-shift observation of plant activities was maintained by NRC personnel from Regions I and II and by a reactor operator examiner from an NRC contractor. Also, Region I inspectors conducted a review of non-licensed personnel training and continued periodic coverage of testing and radiation protection activities. Additional Region I personnel were on site during portions of the period to augment the resident inspection staff.

1.2 Facility Restart Operations

During the period of December 13, 1985 to January 10, 1986, the significant TMI-1 restart operational milestones included: (1) power escalation and main turbine generator operation and turbine runback test at the maximum achievable power testing plateau, (2) turbine trip/reactor trip from maximum achievable power, and (3) return to power operation, marking the completion of the restart test program. Subsequently, the plant was able to achieve operation at 100% of rated power and additional full power test data were taken. The chronological summary of plant operations during the period is presented below.

Date	Time	Operational Highlight or Milestone
12/13/85	7:00 a.m.	Reactor at 75% of rated power
12/27/85	4:16 a.m.	Region I Administrator authorized the licensee to escalate power to the maximum achievable power plateau
	4:20 a.m. - 8:55 a.m.	Increased power to 87.5% at 3% per hour; power escalation stopped when approaching the once through steam generator operating level limits
	1:37 p.m. - 1:50 p.m.	Conducted loss of main feedwater pump runback test from 87.5% of rated power and returned power to 87.5%
1/2/86	12:04 p.m.	Conducted turbine trip/reactor trip test from 88% of rated power
	1:10 p.m.	Tripped reactor coolant pumps for emergency feedwater system initiation testing
	1:17 p.m. - 1:37 p.m.	Reactor coolant pumps restarted, providing forced circulation flow
1/3/86	10:28 p.m.	Region I Administrator authorized the licensee to return to power operations
	10:29 p.m.	Commenced control rod withdrawal for reactor startup
	10:55 p.m.	Reactor critical
1/4/86	3:26 a.m.	Main turbine generator connected to regional electrical grid
	3:43 a.m.	Reactor trip due to turbine trip caused by high level in moisture separator 1C
	11:09 a.m.	Commenced control rod withdrawal for reactor startup
	11:56 a.m.	Reactor critical
	2:15 p.m.	Main turbine generator connected to regional electrical grid
	10:00 p.m.	Reactor at 90% of rated power

Date	Time	Operational Highlight or Milestone
1/5/86	7:00 a.m.	Reactor at 91% of rated power, secured on-shift inspection coverage
1/6/86	2:05 p.m.	Reactor at 100% of rated power
1/10/86	4:00 a.m.	Reactor power reduced to 75% in order to take a main feedwater pump out of service to assess high pump vibrations

1.3 Operational Events

Several events or other matters occurred during this inspection period that were considered either operationally significant or of special interest to the TMI-1 Restart Staff. These items are discussed below.

On December 17, 1985, a contamination event occurred when noble gas was released into the auxiliary building atmosphere during replacement of a waste gas compressor filter. All workers leaving the building were frisked by health physics technicians. Seven workers and one region-based NRC inspector were slightly contaminated. In the case of the NRC inspector, only his hard hat was contaminated. The licensee estimated personnel exposures of about 4E-4 millirem from the contamination.

On December 30, 1985 at 1:50 a.m., the licensee declared an unusual event condition due to a release of noble gas monitored by the plant effluent monitor. The unplanned release was due to failure of a makeup pump (high pressure injection pump) shaft seal. Although the plant effluent monitor went below the alert level at approximately 2:30 a.m., the licensee decided to stay in the unusual event condition until the affected pump was drained and isolated. The licensee secured from the unusual event at 4:20 a.m.

During power ascension on January 5, 1986, following the reactor trips that occurred on January 2 and 4, 1986, steam generator level versus reactor power tracked lower than during the power escalation program in which maximum achievable power was 88%, due to high operating water level in the steam generators. The licensee attributed the change to a redeposition of fouling material in the steam generators. Consequently, the plant was able to achieve full power operation on January 6, 1986, with steam generator water levels well within operational limits. Subsequently, the licensee conducted full power tests that were deferred because of the previous power limitations. Startup testing was completed on January 9, 1986. Reactor physics testing was completed by January 16, 1986.

1.4 Summary

This inspection included restart testing activities for portions of the 75% and maximum achievable power plateaus, and subsequent plant operations at 100% of rated power. During this period there were no interruptions of the restart testing program due to equipment problems or for other reasons. However, an unplanned reactor trip delayed the plant startup, following a planned reactor trip from maximum achievable power, for several hours. The shift inspectors referred only implementation matters or status questions to shift supervisory personnel and referred programmatic matters (event followup, design or procedure adequacy problems) to resident and region-based NRC personnel. Resident and region-based personnel interfaced with licensee support groups in followup to shift inspector referrals/concerns. The staff's observations and findings regarding plant operations and testing and licensee response to operational events is discussed in the report sections that follow.

2. Shift Inspection Activities

2.1 Scope of Review and Observations

During the period of December 13, 1985 - January 5, 1986, the TMI-1 Restart Staff continued its augmented shift inspection coverage. The NRC shift inspectors assessed the adequacy and effectiveness of operating personnel performance based on the inspectors' observations of operating and startup activities to determine that:

-- operators are attentive and responsive to plant parameters and conditions;

-- plant evolutions and testing are planned and properly authorized;

-- procedures are used and followed as required by plant policy;

-- equipment status changes are appropriately documented and communicated to appropriate shift personnel;

-- the operating conditions of plant equipment are effectively monitored and appropriate corrective action is initiated when required;

-- backup instrumentation, measurements, and readings are used as appropriate when normal instrumentation is found to be defective or out of tolerance;

- -- logkeeping is timely, accurate, and adequately reflects plant activities and status;
- -- operators follow good operating practices in conducting plant operations; and
- -- operator actions are consistent with performance-oriented training.

The shift inspectors' observations included, but were not limited to, those reactor plant operation and startup testing activities, periodic surveillance and maintenance testing activities, and preventive and corrective maintenance activities listed below.

Reactor Plant Operation and Startup Testing Activities

- -- routine control room operations including annunciator alarm response and control room logkeeping
- -- operating and emergency procedures discussions with shift supervisors, shift foremen, control room operators and shift technical advisors
- -- periodic inspection observation tours of areas outside the control room, including diesel generator rooms, emergency feedwater rooms, control building, turbine building, auxiliary building, intermediate building, electrical switchgear rooms, and outside buildings and yard areas
- -- routine operations and maintenance planning briefings between plant operations manager and shift supervisors
- -- preparations for underwater inspection of a river water pump to verify proper lubrication connections
- -- establishment and maintenance of cold weather protection controls
- -- operating crew equipment tagging and lineup preparations for turbine-driven emergency feedwater pump 1A controller replacement
- -- special shift crew briefings by the Vice President and Director of TMI-1 regarding past performance and expected operating practices
- -- shift crew actions in response to purge valve AH-V-113 found to be leaking greater than prescribed limits during performance of surveillance procedure 1303-11.18D

-- operating crew response to spurious automatic start of makeup pump 1A auxiliary oil pump

-- shift crew assessment and critique of contamination incident that occurred during waste gas system maintenance on December 18, 1985

-- operating personnel actions performed in makeup pump rooms during startup of makeup pump 1B and securing of makeup pump 1A

- operating crew changeover of letdown coolers to investigate possible source of primary water leakage into intermediate closed cooling water system

-- operating crew preparations for post maintenance leak testing of neutralizer pump 1B seal replacement, performed in May 1985

-- operator response to control room annunciator alarms for "rods symmetrical" and "inhibit rod out motion" received twice in close succession

-- operating crew preparations for mechanical modification of letdown radiation monitor RM-L-1 flow controller

-- operating shift response to failed river water inlet temperature detector, assumed caused by river ice buildup tearing detector away

-- operating crew performance of power escalation from 75% to 87.5% of rated power at 3% per minute

-- operating crew and test personnel briefings for and performance of integrated control system tuning tests at 87.5% of rated power

-- operating crew and test personnel performance of turbine runback test on loss of main feedwater pump

-- power escalation to 90% of rated power when average coolant temperature was raised 5 degrees F for physics testing

-- shift crew and test personnel briefings for and conduct of planned turbine trip/reactor trip on January 2, 1986

-- control room operator withdrawal of shutdown group rods

-- operating crew response to overheating pump for the hydrogen/oxygen analyzer

- -- operating crew preparations for plant startup following the planned reactor trip
- -- reference leg filling for OTSG 1A level transmitter for LT-3 and LT-5
- -- control room operator withdrawal of safety group rods
- -- turbine generator startup
- -- operating crew response to unplanned turbine trip/reactor trip on January 4, 1986
- -- operating and engineering staff post-trip review of unplanned reactor trip
- -- operating crew performance of reactor and turbine generator startup following unplanned reactor trip on January 4, 1986
- -- power escalation to 91% of rated power

Periodic Surveillance and Maintenance Testing Activities

- -- main feedwater pump testing per operations surveillance procedure OPS-S101
- -- emergency feedwater pump 1A controller replacement post-maintenance testing
- -- portions of reactor protection system surveillance activities
- -- portions of control rod movement tests per surveillance procedure 1303-3.1
- -- pressurizer power operated relief valve monthly surveillance testing per surveillance procedure 1303-11.45
- -- portions of high and low pressure injection analog channels quarterly testing per surveillance procedure 1303-4.11
- -- portions of area radiation monitors monthly calibration tests per surveillance procedure 1303-4.15C
- -- fire system testing and flushing of deluge/sprinkler system per surveillance procedure 1303-12.13
- -- main feedwater pump flow instrument calibration to troubleshoot different transmitter indications at same feedwater flow location, per job ticket CI403, dated December 20, 1985

- post maintenance testing of new controller for turbine-driven emergency feedwater pump 1A, using surveillance procedure 1300-3G
- portions of power range nuclear instrumentation calibration per surveillance procedure 1302-1.1
- portions of emergency feedwater pump flow testing per surveillance procedure 1300-3G A/B and adjustments of valve controller steam inlet pressure to various settings to assure minimum pressure and flow design requirements are met
- decay heat river water system weekly surveillance testing
- special operability testing of letdown isolation valve MU-V-3
- control rod patch panel verification per surveillance procedure 1301-9.2
- letdown isolation valve time delay relay testing
- emergency feedwater pump 2A testing per surveillance procedure 1300-3F

Preventive and Corrective Maintenance Activities

- troubleshooting and repair of once through steam generator 1A level transmitters LT-3 and LT-5
- turbine-driven emergency feedwater pump 1A controller replacement
- troubleshooting and investigation of makeup pump 1B lube oil pressure switches
- temporary repairs to leaks in secondary system valves and an emergency feedwater riser flange using Furmanite sealant
- repair of soldered hot spots in control room drive cabinet per job ticket CI-231

In addition, shift inspectors conducted or contributed to the following special reviews of facility design and operational matters or of the licensee's administrative controls programs.

- closure controls for fire doors
- hydrolazing (water spraying) of building spray/decay heat vaults to reduce contamination and radiation levels

- -- partial valve lineup verification for emergency feedwater pumps
- -- control room computer alarm priority system
- -- operating crew response to out of tolerance secondary plant equipment readings, while operating at 75% of rated power
- -- use of scaffolding for planned maintenance activities, such as emergency feedwater pump 1A controller replacement
- -- worker use of piping and valves as footholds/support in lieu of ladders or scaffolding
- -- shift crew trending of reactor coolant system leakage
- -- barrier control practices for entrances to high radiation areas
- -- effects of vent header pressure changes on reactor coolant system leakage measurements
- -- trending of pressurizer power operated relief valve setpoint check monthly surveillance procedure test results for tests conducted since June 1985
- -- operating staff trending and followup to out-of-specification readings for emergency diesel generators jacket cooling water temperatures
- -- storage controls of portable equipment in safety-related spaces
- -- makeup pump 1A inboard seal failure event that occurred on December 29, 1985
- -- nitrogen blowdown of OTSG 1A level transmitter root valve FW-V-1093 to free blocked line caused by Furmanite repair

2.2 Assessments of Shift Inspectors

2.2.1 General

The shift inspectors assured that any potentially adverse safety concern or regulatory finding was identified promptly to both appropriate licensee supervisors and the NRC's TMI-1 Restart Manager. Those items requiring additional staff review or followup are described in paragraph 3 of this report. Also, at the end of their assigned period of shift inspection activities, the inspectors provided their general assessment of facility operational readiness and

personnel performance. As noted below, these general findings included, as applicable, the collective inspector views related to operating staff performance, maintenance, surveillance, radiological controls, training, emergency planning, and physical security. The overall conclusions of the TMI-1 Restart Staff are provided in the sections that follow.

2.2.2 Operator Performance

Licensed operators continued to demonstrate their detailed knowledge of facility design and daily plant status. This was evident in their routine actions on shift and in response to alarms and changing plant conditions. It was further evident in their overall good performance in response to unexpected events such as the unusual event of December 30, 1985, and for the unplanned reactor trip on January 4, 1986. The shift organization in the control room continued to demonstrate discipline and overall good noise control in the control room. These same positive attributes were evident during the off-normal situations such as during the unplanned reactor trip.

Shift inspectors continued to note that, at the end of shift, shift foreman (SF) routinely copied the control room operators log entries for routine activities. Although the shift foremen were diligent in independently recording entry in to technical specification action statements and other off-normal events required by administrative procedures, for routine entries the SF log lost its independence. This could impact post-event reviews, since routine entries could be used in reconstructing events. The Manager of Plant Operations acknowledged the inspector's observations and he indicated that he would review the matter. This will be routinely followed by the resident inspectors in future inspections.

Of particular focus during this inspection period was licensed operator performance during the turbine trip test of January 2, 1986. Overall, crew performance was very good. All members were disciplined and attentive. They maintained their stations, observed appropriate instrumentation, reported important readings and alarms, and made appropriate control manipulations. They were directed formally by the Manager of Plant Operations, who kept them apprised of overall plant status, concerns, and impending actions. Despite the presence of many operators and observers in the control room, order was maintained and the noise level was acceptable.

The test was conducted according to procedure. Prior to the test, a clear, concise briefing was conducted by the Manager of Plant Operations and a test engineer. Prerequisites, limits and precautious and procedural steps were read and discussed appropriately. Individual operator responsibilities were clearly assigned. It should be noted, however, that TP 800/9, STR-1 had been completely rewritten during the week before the test. STR-2 was not approved formally until December 31; and, three hours before test time, the control room had not yet been provided with a controlled copy. Fifteen minutes before initiation of the test, operators recommended a change to an individual step, which was incorporated as a test exception by the engineer in charge of the test procedure. During the test, the Quality Assurance (QA) observer independently cautioned operators to ensure that this change was not overlooked. Time pressures clearly affected this process but no adverse safety conditions resulted.

The potential for operator error could have been reduced by more timely provision of the controlled copy of the procedure and by formal incorporation of changes identified prior to test initiation.

Following the reactor trip, immediate actions of ATP 1210-1 were clearly read by the shift foreman. He waited for responses to action or verification requirements before proceeding to succeeding items. Formal communications during the rapidly evolving post-trip situation were good. Immediate actions were promptly carried out as evidenced by starting of the second makeup pump four seconds after reactor trip. The failure of MU-V3 to isolate letdown was promptly detected. Since the pressurizer outsurge due to post-trip cooling was stopped at an acceptable level, the decision not to manually intervene immediately was demonstrated to be acceptable.

Annunciators were observed before they were silenced. Not all of them were formally announced, but there was no indication that other than nuisance alarms were dismissed without announcements. Overriding of the nuisance alarm for reactor coolant system "Loop Flow High", which repeatedly entered, then cleared, helped minimize noise levels and distractions.

Data from the Bailey computer sequence monitor (acquired for post-trip review purposes) were lost. There was no indication of operator error in computer use during the test.

Following the reactor coolant pump trip, equipment problems prevented satisfactory demonstration of emergency feedwater system performance and resulted in EF-P1 being declared out of service. Operator actions, however, were appropriate during conduct of the test. The decision to terminate testing and restart the RC pumps to prevent further steam pressure decrease and to control cooldown was appropriate.

Non-licensed personnel appropriately conducted themselves to support licensed operators during routine and special evolutions or testing. No adverse trends in performance were detected.

Overall, personnel conducted themselves in a competent manner.

2.2.3 Training

Shift inspectors made no specific observations on the licensee's training program. However, based on past TMI-1 Restart Staff reviews into this area, previous conclusions on the training program remain unchanged. Operator performance continued to reflect a strong training program being in place for providing performance-oriented training. Specifics on the non-licensed training program are in paragraph 8 based on Region I inspector review.

2.2.4 Maintenance

For the maintenance activities selected for review, personnel were knowledgeable in the technical aspects of the work. In general, their duties and responsibilities were understood. However, there continued to be evident less than full appreciation of how poor work habits could challenge a safety system. Inspectors continued to note potentially adverse safety actions such as stepping on instrument air lines for climbing in the vicinity of MS-V13A/B, the initiation/isolation valves for steam admission to the turbine driven emergency feedwater pump. Further, the operator for MS-V10A, a bypass valve around MS-V13A, was stepped on for climbing. This occurred despite the fact that applicable job tickets were planned well in advance to provide temporary support or ladders for these activities. Licensee management recognized such poor practices as a problem for which they initiated corrective actions. Apparently they were ineffective, to date, in reaching all personnel to explain the shortcomings of such poor work habits. This matter will continue to be routinely reviewed in future inspections by the resident inspectors.

The troubleshooting for the abnormal performance of the turbine driven emergency feedwater was conducted between January 2 and 4, 1986. A job ticket and surveillance procedure was used to operate the pump on recirculation while it was declared out of service. However, no formal data were taken since the pump startups were termed by licensee representatives as a part of the troubleshooting effort for the pressure regulating valve. Subsequent to proper pressure regulator adjustment, a satisfactory test was conducted and recorded. However, the inspector noted to licensee management that informal aspects of the troubleshooting efforts was a poor practice and could lead to a lack of quality in the overall repair effort if errors were made. No conditions adverse to regulatory requirements were noted but the conduct of troubleshooting maintenance will continue to be routinely reviewed by the resident inspectors.

The Furmanite repair to a leak in a steam generator level sensing line, to a certain extent, lacked good engineering support of the reinjection process. Apparently during their planning effort, licensee representatives did not consider the potential for plugging the instrument line due to the injection of too much Furmanite (a sealing compound). As a result the line became plugged and the Furmanite plug had to be blown into the steam generator. The licensee wanted to restart the plant without a complete understanding of the effects of the Furmanite material in the steam generator. After probing by NRC staff and subsequent verbal discussions among licensee engineers, licensee management concluded that there were no unreviewed safety questions to plant restart. Subsequent to the startup, licensee personnel documented their basis for no unreviewed safety question in a 10 CFR 50.59 evaluation. This problem was indicative of poor technical support for this work item. This item is unresolved pending NRC staff review of the licensee's evaluation (289/85-30-01).

Although approximately 50 work items were completed by the maintenance department between January 2 and 4, 1986, the above examples were symptomatic of a sense of urgency that could have the potential to result in error. Although no adverse safety condition resulted, this is an area that will be routinely reviewed by the resident inspectors.

2.2.5 Surveillance

Surveillance activities were performed by both operations and maintenance personnel. The activities observed were handled in a professional manner. All parties involved were knowledgeable of the various systems. Procedural adherence was strictly observed.

2.2.6 Fire Protection

During inspection of the safety related areas, shift inspectors continued to observe labeled fire doors "ajar" (not fully closed, leaning on the latch mechanism). It appeared that the doors had a problem with their closing mechanisms and that personnel were not attentive enough to assure proper closing of the doors. See paragraph 3.2.2 for details on the TMI-1 Restart Staff followup review.

No adverse conditions to fire safety were noted.

2.2.7 Radiological Controls

During this period the licensee culminated efforts to decontaminate the decay heat and building spray vaults to permit access sufficient for observations without protective clothing. This was conducive to enhancing management presence in all areas of the plant.

On December 22, 1985, a radiological controls area sign was noted to be down and not observable. The group radiological controls supervisor (GRCS) took corrective action but this was a precursor of a more significant event. On January 9, 1986, an individual walked into a high radiation area without proper dose rate equipment. See paragraph 6 for details.

Overall, proper radiological control practices were implemented.

2.2.8 Physical Security

No conditions adverse to plant physical security were observed.

2.3 Conclusion

Operators continued to conduct themselves in a competent manner and their actions reflected a strong performance-oriented training program. Preparation for the turbine trip test was conducted at a fast pace but the pretest briefing had an organizing effect such that no adverse regulatory or safety conditions resulted. In general, operators were responsive to daily plant problems as they arose.

The maintenance department conducted an ambitious work list in a short period for the outage after the turbine trip test. That pace coupled with poor technical support on certain work items caused some

errors. Workers continue to exhibit poor practices in certain instances in which their actions could have an affect on the primary plant. Apparently licensee corrective actions to date where incomplete.

Overall, procedures were properly implemented. Radiological control practices were good, however, there was a lapse in personnel attentiveness to reposting a high radiation area sign.

3. Plant Operations

3.1 Scope of Review

TMI-1 Restart Staff inspectors periodically inspected the facility to determine the licensee's compliance with the general operating requirements of Section 6 of the Technical Specifications (TS) in the following areas:

-- review of selected plant parameters for abnormal trends

-- plant status from a maintenance/modification viewpoint including plant housekeeping and fire protection measures

-- control of ongoing and special evolutions, including control room personnel awareness of these evolutions

-- control of documents including logkeeping practices

-- implementation of radiological controls

-- implementation of the security plan including access control, boundary integrity, and badging practices

The inspectors also focused their attention on the areas listed below.

-- control room operations during regular and backshift hours, including frequent observation of activities in progress, and periodic reviews of selected sections of the shift foreman's log and control room operator's log and other control room daily logs

-- followup items identified by shift inspector activities (see paragraph 2)

-- areas outside the control room

-- selected licensee planning meetings

As a result of this review, the inspectors reviewed specific events in more detail as described in the sections that follow.

3.2 Findings

3.2.1 General

Licensee management continued their presence and involvement in daily activities. The quality assurance department sustained their presence and detailed involvement in licensee activities. However, the pace of activities between January 2 and 5 was hurried and it apparently caused a lapse in complete review of technical problems in preparation for startup after the turbine trip. Specific problem areas were addressed in paragraph 2.2 for the short outage and performance problems noted below on a long term basis were indicative of this problem, that is, the thoroughness of management and technical support personnel review of plant problems.

3.2.2 Fire Doors

The inspector reviewed the status of fire door maintenance and surveillance activities. This review was conducted because of numerous shift inspector observations of fire doors being not fully closed.

As part of this review, the inspector toured Unit 1, held various discussions with licensee personnel, and reviewed the following documents.

-- Preventive maintenance (PM) procedure U-27, "Functional Testing of Fire Doors," Revision 0, dated June 19, 1985

-- Surveillance procedure (SP) 1301-1, "Shift and Daily Checks," Revision 58, dated September 5, 1985

-- SP 1303-12.20, "Fire Door Inspection - Control Building," Revisions 3 and 4, dated December 4, 1984 and December 20, 1985, respectively

-- SP 1303-12.21, "Fire Door Inspection - Primary Side," Revision 4, dated May 17, 1985

-- SP 1303-12.22, "Fire Door Inspection - Screen House," Revision 4, dated December 11, 1985

-- TMI-1 Fire Hazards Analysis, Fire Protection Program and associated documentation

During a tour of the intermediate building on December 17, 1985, at approximately 7:45 a.m., the inspector observed fire door I-107 tied open with a piece of rope. No one was

observed in the immediate area. At approximately 11:30 a.m., the fire door was still open. The inspector brought his concern to the attention of the shift supervisor; and, shortly thereafter, the fire door was closed.

During discussions with cognizant licensee personnel, the inspector was told that fire door I-107 does not separate fire areas; it only separates fire zones. Also, it is not part of a three hour rated fire wall and was not evaluated in the licensee's Fire Hazard Analysis submitted to NRR as part of their Fire Protection Program. After reviewing related documention, the inspector agreed with the licensee representatives. The safety significance of leaving this fire door tied open was minor and was not a violation of technical specifications.

The inspector observed that most licensee personnel are not aware of which fire doors must be kept closed. Some fire doors that do not have to be kept closed are labeled "Keep Closed." Other fire doors that do not have to be kept closed are not labeled at all (fire door I-107 was this type of fire door). The inspector concluded that the labeling of fire doors was confusing and brought this to the attention of the licensee. Licensee management agreed that the present labeling of fire doors was confusing and personnel may not be sure which fire doors must be kept closed.

On January 6, 1986, the licensee removed "Keep Closed" signs from all fire doors that do not have to be kept closed. Only those fire doors that are required by technical specification to be kept closed are now labeled "Keep Closed." The licensee stated that they would like to see the fire doors that are not labeled remain closed as much as possible and will rely on employee judgement to achieve this. The inspector found the licensee's action in this area to be satisfactory and had no further questions.

The inspector also reviewed maintenance activities associated with these doors. PM procedure U-27 provides an acceptance criterion that normally-closed fire doors will close and latch when started from a 3/4 opened position and released. However, during discussions with licensee personnel, the inspector was told that PM procedure U-27 had not yet been implemented. The licensee committed to place this procedure into their preventive maintenance schedule beginning in January 1986, and will initially perform it twice per year. Based upon an evaluation of results from this procedure, the licensee may reduce the frequency to once per year. The inspector found this action to be satisfactory and had no further questions in this area.

During the inspector's review of surveillance procedures associated with the fire doors, the inspector noted a discrepancy. Fire door D-108, which is in a three hour fire rated wall, did not appear in any surveillance procedures. This condition existed from December 16, 1985 through December 19, 1985, when the fire door was not checked as part of SP 1301-1.

Fire door D-108 was originally contained in SP 1303-12.22, Revision 3, along with screen house fire doors. The licensee decided that fire door D-108 would be more appropriate in SP 1303-12.20, along with control building fire doors. Procedure change requests were initiated to remove fire door D-108 from SP 1303-12.22, Revision 3, and to add it to SP 1303-12.20 as Revision 4. These procedures were attached and went into the change process as one package; both should have been issued together as new Revision 4 procedures. However, SP 1303-12.22, Revision 4, was issued on December 11, 1985 and SP 1303-12.20, Revision 4, was not issued until December 20, 1985, when the inspector brought this issue to the licensee's attention. Therefore, between December 16-19, 1985, the licensee did not survey fire door D-108. The inspector concluded that the above noted procedure change issuances were not properly coordinated and this resulted in an apparent violation of TS 4.18.7.2.c. (289/85-30-02)

The licensee stated that security personnel routinely tour Unit 1 and shut any fire doors that may be open. The inspector reviewed the security logs for the period of December 16-19, 1985. Security personnel did tour the diesel room area; however, they did not sign off on fire doors, only security doors. A senior licensee representative from security stated that checking closed fire doors was not part of the security guards' routine, but they would probably close a fire door if it was open. The inspector had no further questions in this area.

3.2.3 PORV Exception and Deficiency (E&D) Data Review

The inspector reviewed data from surveillance procedure 1303-11.45, "PORV Setpoint Check," Revision 5, dated September 3, 1985, that was performed on December 20, 1985. This review was conducted because the PORV was declared inoperable due to three identified deficiencies.

The inspector found the surveillance package to be complete with three deficiency sheets attached. The first deficiency found the PORV high pressure reset to be out of tolerance high. The second deficiency found the PORV temperature interlock trip to be out of tolerance high. The third deficiency found the PORV low pressure reset to be out of tolerance low.

The inspector questioned cognizant licensee personnel regarding the cause of these three deficiencies. The inspector was told that instrument drift, dirty potentiometers, or potentiometer adjustment relaxation were the most probable causes. Corrective action for these three deficiencies consisted of recalibrating the bistables in accordance with procedures.

A review of SP 1303-11.45 data from the past twelve months was conducted to determine if any obvious adverse trends existed. The inspector noted that the PORV temperature interlock trip was out of tolerance during the March and November 1985 surveillance tests.

The inspector brought his concern to the attention of the licensee. A representative stated that three recurrent deficiencies on the temperature interlock function would be picked up during trending reviews and action would probably be taken to correct the problem. In this case, the module would probably be replaced with a new module. As a result of the inspector's concern, the licensee initiated a corrective maintenance job ticket.

The inspector concluded that corrective action taken by the licensee in response to the these deficiencies was appropriate for the circumstances. The resident inspectors had no further questions in this area but will continue to routinely follow deficiencies associated with the PORV.

During the previously-mentioned review of past data from SP 1303-11.45, the inspector noted a confusing statement associated with the reset point for the PORV temperature interlock. The desired trip point is 275 F (-2.500 V) and the desired reset point is 278 F (-2.400 V). A footnote to the reset point states, "Required reset point is 0.100 $\pm$ 0.050 V above trip point." However, the inspector noted several instances in which several I&C technicians used the wrong reset band. The reset band should be based upon the as-left trip point, not necessarily the desired trip point.

The inspector brought this concern to the attention of cognizant licensee representatives. They agreed with the inspector that confusion exists among some I&C technicians as to what the reset band should be for the PORV temperature interlock. The licensee committed to revise SP 1303-11.45 so that it is clearly understood that the reset point is based upon the as-left trip point.

The inspector concluded that the probability of setting the reset point out of tolerance exists. Although the procedure was somewhat confusing, the inspector found it to be adequate. Several instances were noted in which the wrong tolerance band was used; but, by chance, the as-left reset point was in tolerance to the proper acceptance criteria.

3.2.4 Makeup Pump Lube Oil Pressure Switches

On several occasions, the license has noted problems with a oil pressure switch associated with makeup pump 1A in that the switch was not stopping the motor driven lube oil pumps after proper oil pressure had been achieved using the attached lube oil pump. The motor driven oil pumps are used to supply lube oil when starting the makeup pump. Under normal running operations the motor driven oil pumps are secured and an attached lube oil pump supplies the necessary oil. To secure to the motor driven oil pump, when proper oil pressure is generated by the attached oil pump, the pump has oil pressure switches installed as part of the control circuitry. The original lube oil pressure switches were not environmentally qualified. The switches were replaced with a qualified switches. Evaluation by the licensee, determined that the pressure setting of switch was too high. The switch was eventually readjusted and is working correctly.

The inspector reviewed and discussed the work that was performed on all three makeup pumps with plant engineering and maintenance personnel. Review of technical specifications indicated that the licensee remained in compliance of their technical specifications. Work performed was documented in accordance with applicable station procedures. The inspector concluded that the inability of the lube oil switch to function as designed did not degrade the ability of the makeup pump to perform its safety-related function.

3.2.5 Diesel Generator Standby Coolant System

As part of the routine plant tour, the inspector reviewed the auxiliary operators' logs. The jacket coolant and lube oil temperatures kept warm by the standby coolant system were consistently low out of specification. The normal values for jacket coolant temperature were expected to be

120 F to 140 F. The readings obtained by the auxiliary operators on a shift basis were between 112 F and 115 F. The temperature of the lube oil is to remain above the alarm setpoint of 90 F. The cause of the low temperatures was attributed to check valve leakage in the standby coolant system. (See NRC Inspection Report 50-289/85-26.)

The inspector queried the licensee whether the lower temperatures had an adverse affect on the operability of the diesel. From discussions with plant engineering and operations personnel, the licensee demonstrated that the low jacket coolant temperature (temperature greater than 100 F) would keep the lube oil temperature above 90 F. The actual lube oil temperature critical limit was approximately 65 F. Review of diesel support systems indicated that lube oil temperatures less than 65 F was the limiting condition associated with "keepwarm" systems. Review of licensee procedures demonstrated that sufficient operator action was required to ensure that the lube oil temperature would not drop below 90 F.

Further, licensee representatives indicated that the check valves in question would be repaired during the next outage after the new internal components were received from the manufacturer. The inspector questioned the licensee's philosophy of daily logs having out-of-specification readings (see also paragraph 3.2.8). It appears that the licensee was willing to accept out-of-specification readings until repair of the check valves could be accomplished. The licensee acknowledged this concern and they stated that they would review the applicability of the current specification values.

3.2.6 Letdown Cooler Isolation

The inspector reviewed the sequence of events and the chemistry data associated with determining which letdown cooler was leaking. The inspector initially reviewed the sequence of events during NRC Inspection 50-289/85-27. At the completion of that report the licensee was evaluating the current information to determine which cooler was leaking. From the chemistry plots, the licensee was able to determine that the 'B' letdown cooler had a leak rate of approximately 1 liter/day. The 'B' letdown cooler was isolated both on the primary and secondary side. The cooler has been restricted to limited use under the direction of the plant operation manager. Plant maintenance has started the necessary engineering and maintenance preparation to support replacement of the cooler during the next refueling outage.

The inspector reviewed the chemistry data and licensee reasoning for their conclusion of the "B" cooler leakage. The inspector discussed with plant maintenance and operational personnel the limited use and the licensee's schedule for cooler replacement. It was concluded that limited use of the cooler would not adversely affect plant safety. The unavailability of a second cooler would only affect plant operations during startups, and affect the length of time to restart the plant from a cold shutdown condition. The inspector noted that because the leakage was small, the licensee initially had difficulty in determining which cooler was leaking. After the 'B' cooler had been isolated on both the primary and secondary side and the chemistry in the intermediate close cooler was trended for a sufficient period of time, the licensee was then able to determine which cooler was leaking.

3.2.7 Temporary Digital Readout for RM-A5

In order to easily read the indicated counts for the main condenser offgas radiation monitor RM-A5, I&C technicians connected a portable test equipment to the permanent readout in the control room. The portable test equipment was placed (unsecured in any manner) on top of the cabinet containing RM-A5 readouts. The digital readout of the test equipment was thus used by the operators as an accurate method of quickly obtaining the count per minute reading for RM-A5.

The inspector questioned an I&C foreman on whether the test equipment was considered permanent and should be considered a missile hazard.

The foreman stated that the equipment would remain until corporate engineering had designed a permanent resolution. The permanent resolution may be a new readout or just using existing arrangements. The foreman, however, acknowledged the inspector's concerns about the test equipment being a missile hazard. He immediately directed that securing straps be placed on the test equipment to ensure that it could not become a missile hazard.

The inspector reviewed the interim solution and considered it acceptable until the final engineering resolution was developed.

3.2.8 Auxiliary Operator Logs

The inspector reviewed selected primary system and secondary system auxiliary operator (AO) logs completed during the latter part of 1985. The AO logs are used by auxiliary

operators to record numerous plant data and observations. If any data or observations are out of specification as indicated by the reference values in the AO logs, the auxiliary operator circles it to alert the reviewers (shift foreman and operations engineers). Appropriate action, if any, is then taken.

The inspector observed that there were frequent red-circled items throughout the AO logs covering a period of several months. A licensee representative stated that the AO logs are used for trending purposes and that the reference values may not be accurate because the plant had not been operated for a long period of time. The licensee representative also stated that the vast majority of the red-circled items are not indicative of problems, and if they are, they are appropriately dispositioned.

The inspector concluded that the manner in which AO log out of specification entries are being resolved was a poor operating practice. A red-circled item should alert operations personnel that impending problems are evident. If red-circled items are passed by week after week, the effectiveness of the AO logs are greatly reduced. It could condition operators to treat "abnormal" readings as "normal" readings and corrective actions may not be taken. If the reference values are not appropriate for the mode of operation, new reference values should be determined. The resident inspectors will continue to routinely follow this area.

3.2.9 Annunciator Black Board

On several occasions, the shift inspectors noted certain annunciator alarms that remained lit for extended periods of time and other alarms that remain on permanently. For each alarm the inspector discussed the reason or cause for the alarm with plant operations personnel. In certain instances the alarms were due to testing in the plant, however some alarms were due to actual plant conditions and the way the circuitry was designed.

Discussions with plant management indicated that the licensee was working toward having all annunciators out when the plant was operating at full power. The inspector discussed the major annunciators that were continuously lit during plant operations. In each instance, the licensee satisfactorily resolved the inspector's concerns about alarms that are continuously lit. However, the inspector questioned why ground indications on both station batteries were periodically received. Plant operations personnel stated that job tickets were being written or have been written to correct the problem. The inspector verified that the

licensee was pursuing these problems; but he also noted that the battery ground problem was not being resolved aggressively by licensee management. The inspector had no further questions in this area.

3.2.10 Procedure Implementation

As a result of a shift inspector concern identified during the plant startup conducted on January 4, 1986, which related to the performance of a heat balance at approximately 30% power, the completed plant startup procedure 1102-2 was reviewed and discussed with the licensee. The plant startup procedure requires the performance of a heat balance at "approximately 30% power." This step in the completed procedure was initialled as having been performed. A search of records showed a heat balance was performed at 41% power.

Based on discussions with licensee personnel, the computer used for performing the heat balance was unavailable at 30% power. Licensee management was present in the control room when 30% power was achieved. Since the heat balance was used to calibrate the power range instrumentation and the procedure calls for additional heat balances at progressively higher power levels prior to achieving 100% power, the decision was made to perform the heat balance specified at approximately 30% power, later at 41% power when the computer was available. The actual power at which the heat balance is performed is immaterial for what it is intended to accomplish, that is, for verifying the proper response of the power range instrumentation. Accordingly, licensee management determined the performance of the heat balance at 41% satisfied the approximate 30% specified in the procedure. Based on this determination, the step requiring the heat balance at approximately 30% power was signed off. At the 41% indicated value, the power range instrumentation was recalibrated to 43% based on the heat balance calculation. The inspector had no further questions relative to this matter

Procedure 1102-4, "Power Operation," in discussing the heat balance requirements specifics heat balances at 15 and 30% power. This was identified as a typographical error and a Procedure Change Request (PCR) has been prepared to have the procedure read 15 to 30% power to agree with the same requirement in Enclosure 5 of Procedure 1102-2.

3.2.11 Reactor Plant Operation and Testing Activities Between January 5 and 10, 1986

As previously noted in prior inspection reports, steam generator water levels had been higher than expected due to apparent deposits on the secondary side of the steam generator tubes. Following the most recent reactor startup on January 4, 1986, the steam generator levels were at a lower level than had been expected. Due to the importance of steam generator levels to plant operations, a review was conducted to develop some assurance that the level readings were accurate. To accomplish this, five steam generator level instrument differential pressures on each steam generator were compared and found to agree with the instrument tolerances.

The inspector verified that technical specification surveillance requirements for the instruments was verified to have been performed as required. The required weekly surveillance checks were verified to have been performed as required in accordance with Surveillance Procedure 1301-4.1, Weekly Surveillance Checks, Revision 26, November 24, 1983. Completed surveillance procedures for December 28, 1985, December 20, 1985, December 13, 1985, and December 7, 1985 were reviewed. Data showed all instruments to be accurate to within the specified acceptance criteria. The inspector had no further questions in this area.

A sampling check of the licensee's control of locked valves was conducted. Two valves BS-V-54A and BS-V-49A, normally locked-open valves, were noted as being unlocked and closed. A review of the control room locked-valve log showed the valve positions were under the control of a surveillance test procedure and that their status was properly documented.

The licensee's activities associated with a drop in instrument air pressure were observed. Considerable personnel activity was noted in the intermediate building in the area of the instrument air compressors by individuals looking for possible instrument air system leaks. Also, announcements were made over the public address system for people using instrument air to discontinue doing so. A further evaluation by the licensee determined the loss of instrument air pressure resulted from the simultaneous venting of a number of air operated isolation valves. The venting of the valves was in accordance with a surveillance procedure 1303-5.1, Reactor Building and "Isolation System Logic Channel and Component Test." This procedure had not been performed previously with the plant at power and the loss of instrument air pressure was not considered. Further

evaluation showed the use of instrument air was well within the capability of two air compressors and that following this experience with the procedure, no problems should be encountered during future performance of the surveillance. Also, the licensee is evaluating a change to the procedure or the addition of a caution to help eliminate any future problems.

During plant operation at 100% power on January 10, 1986, some increase in the "B" main feedwater pump vibration was noted. Reactor power was reduced to approximately 78% and the feedwater pump was removed from service. The source of the vibration was traced to the pump coupling. The coupling was disassembled, cleaned, lubricated, new "O" rings installed, and reassembled. Portions of the pump maintenance and subsequent pump restart were witnessed by the inspectors. The pump maintenance and startup were observed to have been performed in accordance with appropriate procedures and no deficiencies were noted. Quality control involvement in the maintenance activity and subsequent vibration data gathering was also noted.

The repair of the control room position indication of the No. 4 main steam stop valve was observed. This repair required the closing of the stop valve and the replacement of a broken rod associated with the position indication system by I&C personnel. The entire task was well planned between operations and I&C personnel, good communications were established and maintained. The good planning and cooperation between operations and I&C personnel resulted in a swift and successful repair.

3.3 Conclusion

Licensee management and the quality assurance department continued their presence and involvement in daily activities. Problems were noted in the thoroughness and completeness of management review of plant problems or at least in assuring thorough and complete technical support personnel review of plant problems.

The poor operational practice of living with out-of-specification readings in daily logs was indirectly tolerated on a long term basis by intermediate managers, thereby conditioning operators to normal "abnormal" readings. Individual procedure step inadequacies continued to be identified by inspectors indicating a problem with the attentiveness of procedure reviewers and implementers to correct these problems. The labelling on fire doors was confusing and an improperly coordinated procedure review resulted in a violation of a regulatory requirement.

Records of maintenance and surveillance activities were properly retained. These records indicated that appropriate corrective action was issued for routine items needing repair along with proper post maintenance testing.

The startups after reactor trips were conducted in a deliberate and conservative manner and operators continued to demonstrate their highly developed skills in operating the integrated control system in manual.

4. Startup Testing

4.1 Test Program Meeting Summary

On December 17, 1985, a meeting was held at the TMI training center in Middletown, Pennsylvania, to discuss the status of the power ascension program for TMI-1. Meeting attendees as well as the meeting agenda and slides are identified in Attachment 1. The results of this meeting are summarized below.

Because of apparent fouling problems on the secondary side of the steam generators, TMI-1 was not expected to achieve 100% power. The licensee plan of action was to proceed past 75% power around December 27, 1985, and to reach whatever maximum power would be achievable with their present limitations. They would complete power ascension test and around January 2, 1986, conduct the planned reactor trip from maximum achievable power. Then if all proceeded as scheduled, the licensee would start up on January 3, 1986. The NRC staff agreed that completing the power ascension program at the maximum achievable power vice 100% power would be acceptable. However, the licensee was requested to document its plan of action via formal letter. (This was completed by letter, dated December 19, 1985).

The licensee also discussed in detail two situations which arose during the startup. The first involved the EFW turbine-driven pump steam supply safety valves lifting when the pump actuates. The licensee has proposed an alternative interim solution which was acceptable while further investigations were to be conducted. The staff emphasized that a final solution must be achieved by the completion of cycle 6 refueling outage. The licensee was requested to document their plan of action via a letter. (This was completed by letter, dated December 20, 1985).

The second situation involved main steam safety valves controlling steam generator secondary pressure upon a reactor trip instead of the turbine bypass valves. Based upon investigative methods in process, the staff concluded that the licensee was appropriately addressing its concerns. (By letter dated December 20, 1985, the licensee concluded no safety concern exists and they committed to notify the NRC staff of their review of test results by the restart after the eddy current outage planned for March 1986.)

4.2 Power Escalation Testing (Maximum Achievable Power Plateau Testing)

4.2.1 Scope of Review

4.2.1.1 Test Witnessing

At various times during the inspection period, the inspectors witnessed testing in progress on a sampling basis. However, test procedure (TP) 800/2, "Reactor Trip on Turbine Trip," and TP 800/9, "EFW Pump Auto-Start Test," were witnessed in their entirety by the TMI-1 Restart Staff. The tests were observed to verify that:

-- tests were conducted in accordance with appropriate test procedures;

-- prior to performing tests, an adequate briefing was conducted for operations personnel;

-- test prerequisites and initial conditions were met;

-- applicable technical specifications were complied with;

-- operator actions were correct;

-- test engineers were knowledgeable in their duties; and,

-- test results were acceptable.

In addition to TP 800/2 and TP 800/9 witnessing, the following tests were observed and/or their test results independently reviewed by the TMI-1 Restart Staff during this inspection period.

-- TP 800/5, "Unit Load and Steady-State Test"

-- TP 836/1, "Feedwater System Operation and Tuning"

-- TP 849/1, "ICS Tuning at Power"

-- TP 846/1, "Incore Thermocouple Operations Test"

-- TP 885/2, "Turbine Bypass Valve Test"

-- TP 800/2, "Reactor Trip on Turbine Trip"

-- TP 800/9, "EFW Pump Auto-Start Test"

-- OP 1105-14, "Loose Parts Monitoring System"

-- RP 1550-08, "Core Power Distribution Verification"

-- RP 1550-05, "Reactivity Coefficients at Power"

-- SP 1301-9.5, "Reactivity Anomaly"

-- SP 1303-1.2, "RCS Flow Surveillance"

-- OP 1103-16, "Heat Balance"

4.2.1.2 Test Results Review

Test results from the testing program for the 88% and 100% power plateaus were reviewed by the inspector to verify that:

-- test changes were approved and implemented in accordance with administrative procedures;

-- changes did not impact the basic objectives of the test;

-- test deficiencies and exceptions were identified and resolved and resolutions were acceptable;

-- the cognizant engineering group has evaluated the test results and signified that testing demonstrated that design conditions were met; and,

-- test results were within established acceptance criteria or properly resolved.

4.2.2 Licensee Test Results and NRC Findings

Licensee performance of key tests is described in this section. The discussion includes a summary of key test objectives and test results; test performance including operators, test engineers and equipment; and pertinent findings and outstanding problem areas identified and/or NRC findings as a result of testing. Because of the significance of TP 800/2 and TP 800/9, the details on the performance of these tests and their results are discussed separately in paragraph 4.3.

NOTE: Paragraphs 4.2.2.1 through 4.2.2.6 discuss special tests performed at 88% and 100% power levels except for TP 800/2 and 800/9 which are discussed in paragraph 4.3. All tests were completed by January 10, 1986, prior to the end of this reporting period. In some instances, NRC review of

these data was conducted subsequent to January 10, 1986, however the results of this review are included in this inspection report for completeness.

4.2.2.1 Unit Load Steady-State Test (TP 800/5)

The steady-state plant parameters were measured per TP 800/5 at the 88% and 100% power levels. As noted in NRC Inspection Reports 50-289/85-27 and 85-28, the OTSG high water level problem temporarily limited the achievable power to 88%. Upon recovery from the TP 800/2 reactor trip test, the steam generator water levels began to track within the original predicted range up to 100% power level and no longer impose operation limits on the reactor power. The rest of the steady-state plant parameters during power escalation continuously showed good agreement with the predicted values.

4.2.2.2 Feedwater System Operation and Tuning (TP 836/1)

The feedwater system operation was tested per procedure TP 836/1 at the 88% and 100% power levels. The measured feedwater flows and temperatures (after second stage high-pressure heaters) agreed well with feedwater cycle performance predicted values. No unacceptable feedwater system oscillations were observed during these tests.

4.2.2.3 ICS Tuning at Power (TP 849/1)

ICS tuning was completed satisfactorily at 88% and 100% power. The significant portion of this test was a reactor runback on loss of main feedwater pump. On December 27, 1985 at approximately 1:40 p.m., the licensee secured a main feed pump as per the test procedure. In a period of approximately five minutes the reactor rods inserted reducing reactor power from 88% to 70%. The transient was witnessed by the inspector. There were no plant equipment problems and the operators handled the transient properly. Test results were acceptable.

4.2.2.4 Incore Thermocouple (T/C) Operations Test (TP 846/1)

The incore T/Cs were checked at 88% and 100% power levels per procedure TP 846/1; four out of fifty-two T/Cs, identified as out of service during earlier testing, remained out of service during these tests. The remaining 48 operable T/Cs exceeded the minimum requirement of 16 operable T/Cs located in a specified pattern.

A problem identified during previous inspections at lower power plateaus was that the location of the five highest T/C readings as read from Mod Comp computer Area 3 groups 8, 9, and 1C did not agree completely with the selection as determined by the computer program "TCDSPL." The data used for this comparison were taken at two different times. Due to the quasi-steady nature of the system response, and the small temperature difference among the higher T/C readings, this discrepancy was explainable. At the 88% power level test, as the temperature difference among T/Cs increased, the discrepancy only occurred at the fifth highest reading, whereas the first to the fourth highest T/C readings were correctly selected by the computer program "TCDSPL." At the 100% power level test as temperature difference increased even higher, all five highest T/C readings were correctly selected by the computer program "TCDSPL."

Other than as noted above, the functional check of all operable T/Cs and the associated computer system continuously showed acceptable results.

4.2.2.5 Core Power Distribution Verification (RP 1550-08)

The detailed core power distribution at the 88% power plateau was measured by the licensee per procedure RF 1550-08, "Core Power Distribution Verification," using the incore detector system. A procedure temporary change notice (TCN) No. 1-85-0206, dated December 26, 1985), was written to correct the predicted values for performing this procedure at a higher burnup and lower power level than originally planned. The inspector noted the following results:

-- The measured radial peaking factor for each assembly was consistent with the analytically predicted value. The comparison of the highest measured radial peaking factor (1.272) at core location K-11 agreed closely with the predicted value of 1.224.

-- The measured total peaking factor in each fuel assembly also agreed consistently with the predicted value. The highest measured total peaking factor of 1.463 agreed well with the predicted value of 1.416.

-- The measured linear heat rates accounting for various uncertainty factors were within TS 3.5.2.7 limits, as indicated in the following table.

Axial Location from Bottom of Core (ft)	Measured Maximum* Linear Heat Rate (KW/ft)	Maximum Allowable Linear Heat Rate (KW/ft)
11.14	6.98	15.20
9.43	11.82	16.26
7.71	12.26	17.10
6.00	11.88	17.50
4.29	11.75	16.31
2.57	12.00	14.98
0.86	9.20	13.50

*including power spike factor

The licensee also measured the core power distribution at 100% power on January 9, 1986. The inspector reviewed the test results and noted that the measured values were all within TS limits and consistent with the data obtained from 88% power results.

All results were acceptable.

4.2.2.6 Reactivity Coefficients Measurement (RP 1550-05)

The temperature and power coefficients of reactivity at the 88% power level were measured per procedure RF 1550-05. The measured temperature coefficient was -10.17 pcm/F. This value was in the test acceptance range of -14.0 pcm/F ± 4 pcm/F. The temperature coefficient is the sum of the moderator temperature coefficient (MTC) and fuel doppler coefficient. The corresponding MTC at 88% power as derived from this measurement and the extrapolated value for 100% power at an all rods out condition are as follows:

Power Level (%)	MTC (pcm/F)	TS Limits (pcm/F)
88	-8.7	<5
100	-8.2	<0

The measured power coefficient (power doppler coefficient, since RCS temperature was maintained constant during this test) was -8.59 pcm/% power. This value satisfied the safety analysis requirement that the power doppler coefficient be more negative than -5.5 pcm/% power. However, the measured value was slightly out of predicted range of -13.08 pcm/% power ± 4 pcm/% power. The licensee nuclear engineer performed an engineering evaluation and concluded that the measured power doppler coefficient has no impact on nuclear safety.

In addition, the licensee concluded that this value of the power doppler coefficient would not have special significance on operations. This is due to the relatively small contribution of the power doppler coefficient on the overall reactivity calculation. The predicted doppler coefficient is used in two plant procedures: SP 1301-9.5, "Reactivity Anomaly," and SP 1303-15A, "Reactivity Balance." The inspector reviewed the reactivity anomalies plot maintained by the nuclear engineering group since the beginning of this fuel cycle and noted that the measured values consistently agreed with the predicted values.

Further, the inspector witnessed the plant startup on January 4, 1986, and observed that the estimated critical position (14% withdrawal on Group 7) was very close to the actual critical configuration (14.2% withdrawal on Group 7). Based on these observations and independent verification of safety analysis assumed parameters, the inspector concurred with the licensee's engineering evaluation that there is no unreviewed safety question involved.

4.2.2.7 Core Thermal Power (OP 1103-16, "Heat Balance Calculations")

The core thermal power is usually determined by the plant computer (Group 55) which monitors the required input parameters and performs a heat balance calculation. Hand calculation of heat balance is allowed as a backup when the plant computer is not operating. The inspector performed an independent calculation using the plant parameters taken at 10:38 a.m. on January 8, 1986, for comparison.

Test Date	Plant Group 55 Result		Inspector's Calculation	
	(MWt)	(% Power)	(MWt)	(% Power)
January 8, 1986 (10:38 a.m.)	2532.91	99.92	2533.3	99.93

This comparison indicated that the licensee's core thermal power calculation is adequate. Through control room observation, the inspector noted that at about the same time, the power range indications NI-5 through NI-8 were consistent with the calculated core thermal power.

4.3 Reactor Trip on Turbine Trip (TP 800/2) and Automatic Start of EFW Pumps on Loss of Reactor Coolant Pumps (TP 800/9)

4.3.1 Reactor Trip on Turbine Trip (800/2)

4.3.1.1 Test Performance

Restart condition 2.C.(1)(d) requires that prior to completion of the power escalation test program, the licensee demonstrate automatic reactor trip on turbine trip. This test was performed on January 2, 1986, in accordance with TP 800/2, Section 9.2, "Reactor Trip Due to Main Turbine Trip," during which the main turbine was manually tripped from the control room console. Following the trip of the main turbine, the following events were expected to occur.

-- reactor trip on the anticipatory turbine/reactor trip

-- turbine bypass value setpoint transfers to 1010 psig

-- containment isolation on reactor trip and reset features function as designed

-- OTSG levels control at 30 inches by main feedwater

The results of this test are discussed below.

4.3.1.2 Test Results

The test results indicated that the reactor had automatically tripped upon turbine trip. The maximum RCS pressure attained following the turbine trip was 2150 psig. The result was acceptable since it was below the reactor high pressure trip set point of 2300 psig.

In addition to the automatic reactor trip on the anticipatory turbine/reactor trip; OTSG levels were controlled at approximately 30 inches using main feedwater; and partial containment isolation on reactor trip functioned with one exception-letdown line isolation valve MU-V3 did not close. See paragraph 4.3.1.2.1 for further discussion.

During the TP 800/2, reactor trip test, the inspector observed in the control room that the readings from source range instruments NI-1 and NI-2 indicated about 1 to 2 decades difference. This subject was discussed with a cognizant licensee representative. Troubleshooting performed by I&C technicians immediately after the test indicated that NI-1 count rate amplification gain factor was out of tolerance. The gain factor was subsequently corrected per surveillance procedure 1303-7.2, "Source

Range Channel." The inspector witnessed the licensee I&C technicians perform a second confirmatory surveillance test on NI-1 and NI-2 on the following day (January 3, 1986). Surveillance results indicated that both NI-1 and NI-2 had been properly adjusted. (Both instruments properly responded during the unplanned trip on January 4, 1986.)

Another test objective, that turbine bypass valves control turbine header pressure (1010 psig $\pm$ 10 psi), was not satisfied due to lifting of the main steam safety valves. This problem was first identified in the 40% power reactor trip test (NRC Inspection Report 50-289/85-25, paragraph 4.2.3), and a similar plant response was noted in the unplanned reactor trip that occurred on December 1, 1985, at 75% power. This problem is further detailed in paragraph 4.3.1.2.2 below.

There was also a concern as to the effect of the reactor trip on RCS and OTSG leak rates. This is discussed in paragraph 4.4 where inspection efforts concerning RCS and OTSG leak rates are detailed.

4.3.1.2.1 <u>Containment Isolation Valve MU-V3 Failure to Close</u>

As part of the turbine trip/reactor trip at 88% power per TP 800/2, the licensee was to verify that containment isolation valves shut on the reactor trip signal. During this trip letdown isolation valve, MU-V3, failed to shut, although it had previously shut during the trip at 40% power per TP 800/2 during and a later inadvertent trip at 75% power. The failure of MU-V3 to shut was identified as a test deficiency.

Following the test, as part of troubleshooting maintenance, the valve was successfully tested three times, in that, it shut three consecutive times on a simulated reactor trip signal. Further troubleshooting indicated that a 10 second time delay relay (62 X 1/MU-V3), which allows the operator to open the valve after 10 seconds, was defective. This relay was replaced. The retest on the job ticket stated only that the valve was satisfactorily tested by the reactor trip signal. TP 800/2, paragraph 2.1, stated, in part, that one of the test objectives was to verify containment isolation on the reactor trip and that reset features function as designed. The inspector noted that TP 800/2 failed to document the testing of the override/bypass features for certain containment isolation valves.

A licensee representative stated that this was an oversight; however, the reset feature actually applied to letdown isolation valve MU-V3, to allow restoration of letdown based on operator action. The licensee provided documentation that the reset feature for MU-V3 was previously tested August 10, 1981, per pre-operational test, TP 334/2.

The inspector reviewed applicable portions of TP 334/2 and determined that reset function of MU-V3 had been adequately tested at that time. A complete NRC review of TP 334/2 test data has been documented in an earlier NRC inspection.

The inspector questioned whether the reset function for MU-V3 had been adequately tested during the power escalation test program. The retest of job ticket CI 489, which replaced the time delay relay for the MU-V3 reset function, did not clearly document whether the timer and its reset function were fully tested. The inspector determined that there is no surveillance test procedure for the containment isolation function on reactor trip since this is not identified in the technical specification. The ability of MU-V3 to operate is tested quarterly per SP 1303-11.26, "Reactor Building Isolation Valve Cycle Test"; however, this procedure was not used as a retest for MU-V3 repair since it does test the automatic features of reactor building isolation valves.

On January 3, 1986, while the reactor was still shut down, the licensee performed a retest of MU-V3 by inserting a reactor trip signal using the manual trip button. Safety control rods, which had been withdrawn, were reinserted prior to inserting the reactor scram signal. MU-V3 shut after insertion of the scram signal and would not respond to an open signal until after 10 seconds. The inspector witnessed the retest of MU-V3 and observed that the isolation and reset function did perform satisfactorily. There were no further questions concerning the operation of MU-V3.

4.3.1.2.2 Main Steam Safety Valve Actuation Following Reactor Trips (Unresolved Item 289/85-25-05)

During the reactor trip at 40% power performed on October 21, 1985, the main steam safety valves and turbine bypass valves did not respond as expected. After the initial expected lift of the safety valves, some of the safety valves continued to lift and reseat several times essentially providing pressure control in the steam header. The turbine bypass valves failed to completely open and control pressure. This event was detailed in NRC Inspection Report 50-289/85-25.

On November 21, 1985, during normal reactor power operation at 48% power, the licensee, tested and adjusted six selected safety valves in order to correct the above problem. The setpoints of five of the six valves tested were adjusted higher in order to preclude the potential relifts of the valves after a trip. This was detailed in NRC Inspection Report 50-289/85-27.

On December 1, 1985, the plant experienced an unplanned trip while at 75% power. During this transient, the main steam safety valves (safeties) on both steam generators initially lifted. The main steam safeties on the B steam generator appeared to reseat and the turbine bypass valves associated with B steam generator automatically took over and regulated the pressure in the generator. On the A steam generator the main steam safeties continued to lift and reseat several times thus controlling the pressure in the A steam generator. Approximately 12 minutes after the trip, the shift supervisor directed manual control of the A turbine bypass valves to lower steam pressure to below safety valve setpoints.

Results from this trip, indicated the problem had not been resolved by the previous adjustment of safety valve setpoints. As a result, the licensee changed its procedures to have the operator take manual control of the turbine bypass system following a reactor trip. In addition, special monitoring equipment was installed on each valve and television cameras and thermographic instruments were set in place to observe the main steam safeties lift during the scheduled trip at 88% power per TP 800/2.

The trip from 88% power was performed on January 2, 1986. It was agreed by plant personnel that the operators would wait until after the third lift of the safety valves before taking manual control of the turbine header pressure setpoint. On the first lift after the trip, the lifting of the valves were observed on three television monitors and recorded on video tape. On the second and third lifts, several plant personnel were sent on to the roof to personally observe and record which valves relifted. It was observed on the trip that most, but not all, safety valves lifted. On the two subsequent relifts, only four to six valves relifted. As was observed during the earlier trip at 75% power, B steam generator pressure stabilized quicker than A steam generator pressure.

The licensee is currently evaluating data and videotapes to determine the need for further corrective action. Licensee representatives stated that they will have a plan of action and schedule by the eddy current test outage scheduled for March 1986. This item remains unresolved pending further licensee action.

4.3.2 EFW Pump Auto-Start Test (TP 800/9)

4.3.2.1 Test Performance and Results

Restart condition 2.C.(1)(f) requires that prior to completion of the power escalation test program, the licensee demonstrate automatic EFW initiation on loss of all four reactor coolant pumps. This test was conducted following the reactor trip test per TP 800/2.

Similar EFW pump auto-start tests have been performed twice during the power escalation test program; once during the 40% power plateau transient test (TP 800/8, "RCS Overcooling Test") and once during the 3% power plateau natural circulation test (TP 700/2, "Low Power Natural Circulation Test"). These two previous tests demonstrated that EFW pumps automatically started upon tripping both main feedwater pumps. Actuation times and pump discharge pressures were verified in these tests. The objective of TP 800/9 test was to demonstrate that the EFW pumps automatically start on loss of all reactor coolant pumps. Test results indicated that the test objective was met. After verifying the test objective had been accomplished, steam driven pump EF-P1 and motor driven pump EF-P2B were secured and motor driven pump EF-P2A was kept running to support plant operations. Subsequently, all four reactor coolant pumps were restarted in sequence with no unusual plant response observed.

Paragraph 4.3.2.2 below details further licensee action concerning the operation of EF-P1 which were identified during performance of TP 800/9.

4.3.2.2 EFW Steam Driven Pump Relief Valve Actuation (Unresolved Item 289/85-22-02

During inspection 50-289/85-22 it was identified that both EF-P1 steam supply relief valves lifted. Although EF-P1 operated properly, there was a concern that relief valves should not be challenged during routine operation and that a stuck-open relief valve could affect EF-P1 operability. This concern was identified as NRC unresolved item 50-289/85-22-02. Licensee actions concerning this problem are detailed in inspection reports 50-289/85-24 and 50-289/85-25, and paragraph 7 of this report.

During previous troubleshooting it was noted that the relief valves did not lift when only one steam supply valve was opened. As an interim corrective action for the remainder of Cycle 5, the licensee replaced pressure controller PC-5 for steam pressure control valve MS-V6. MS-V6

reduces steam pressure from a main steam header pressure of greater than 900 psi to EFW steam supply pressure of less than 200 psi.

In addition, EF-P1 steam supply valve MS-V13B was jumpered out so that it would not open automatically with the opening MS-V13A during an EFW actuation concurrently. If needed, MS-V13B can be opened manually from the control room. Keeping MS-V13B closed reduces the amount of steam to EF-P1 precluding the lifting of the relief valves. The steam supply to EF-P1 and the operability of EF-P1 were satisfactorily tested several times during the startup test program.

During performance of TP 800/9 pumps EF-P1, 2A and 2B automatically started as required when all four reactor coolant pumps were secured. Although EF-P1 performed satisfactorily in the recirculation mode, licensee personnel were concerned that there may have been insufficient steam supplied to reach sufficient flow and pressure for EF-P1 to supply proper EFW flow to operating steam generators. Based on this concern, EF-P1 was declared inoperable and a 72 hour limiting condition for operation was declared.

Licensee calculations indicated that MS-V6 must open to at least 45% open to supply a sufficient volume of steam for EF-P1 to properly supply operating steam generators. The MS-V6 controller was re-adjusted and the pump tested several times until an opening of 45% and steam supply pressure of greater than 180 psig (but less than 200 psig) was achieved. EF-P1 was satisfactorily tested and declared operable prior to restart after the 88% power trip.

Item 50-289/85-22-02 remains unresolved until the licensee establishes permanent corrective action concerning the operation of MS-V13A and MS-V13B. The licensee has committed to a permanent resolution prior to the startup after the next refueling outage (Cycle 6).

4.4 RCS and OTSG Leak Rate

4.4.1 Effect of Reactor Trips from 88% and 22% Power on RCS and OTSG Leak Rates

The effect of reactor trips from 88% and 22% power on RCS and OTSG leak rates was followed up by the TMI-1 Restart Staff. Based on data review of surveillance procedure (SP) 1301-1, "Shift and Daily Checks," and SP 1303-1.1, "Reactor Coolant System Leak Rate," the inspector noted that both RCS and OTSG leak rates on the days following these trips

(January 3-5, 1986) remained well within the the technical specification's limits and were consistent with the previous results. No abnormal conditions wer observed.

4.4.2 RCS Leak Rate Change Evaluation

During a routine NRC shift inspector review of plant operation data, the inspector noted that the calculated unidentified leak rate varied from -0.12 gpm (2 a.m.) to -0.26 gpm (10 a.m.) on December 22, 1985. The shift inspector noted that while the plant was operating at steady-state 75% power level, the only plant condition that could affect the leak rate result appeared to be a change in reactor coolant drain tank (RCDT) pressure.

To resolve the above discrepancy, this matter was further reviewed by the TMI-1 Restart Staff. The RCP No. 3 seal purge flow is directed to the RCDT. Since this flow is supplied from the reclaimed water system and is not classified as RCS leakage, its contribution to the RCDT mass inventory change has been properly factored into the RCS leak rate calculation. The seal purge flow is assumed to be 100 cc/min per pump or approximately 0.10 gpm for four RCPs. This assumption is consistent with the actual seal purge flow guidance provided in the RCP operation procedure (OP) 1103-6. The seal purge flow local instrument is located inside the reactor building. Due to difficulty in determining the actual flow rate on a routine basis, and because this term is small in nature, the value of 0.10 gpm is therefore taken as a constant in the calculation. Since the RCDT pressure affects the seal purge flow, increasing the RCDT pressure may cause the actual flow rate to deviate from the assumed value of 0.1 gpm which in turn may have a small impact on the leak rate calculation.

The current RCS leak rate calculation used by the licensee was actually field tested during hot functional testing conducted in 1984. Under controlled environmental conditions, the current method was proven to be able to detect RCS leakage in the order of about 1 gpm with a 0.1 gpm variation. The relatively large variation, as observed by the shift inspector on December 22, 1985, was regarded as due to the increase in RCDT pressure and the inherent calculation allowances associated with the current surveillance technique, and therefore was determined to be a normal plant response.

4.4.3 RCS Leak Rate Evaporative Loss Term

Through various inspections conducted since the TMI-1 hot functional test, the evaporative loss term was identified as having contributed to the negative unidentified leak

rate result. In the routine tracking of RCS leakage during the extended period of startup testing program further confirmed this finding; that the correct evaporative loss term for the current plant condition is essentially zero. In the meeting between TMI-1 Restart Staff and the licensee management held on January 2, 1986, the licensee agreed that this evaporative loss term will be set to zero in the RCS leak rate calculation and will be implemented before January 31, 1986, pending the completion of computer software changes.

4.5 Verification of Licensee/Restart Conditions

4.5.1 Verification of License Conditions

Licensee condition 2.C.(8)3 states that "GPU Nuclear Corporation shall complete its post-critical test program at each power range (0-5%, 5%-50%, 50%-100%) in conformance with the program described in Topical Report 008, Revision 3, and shall have available the results of that test program and a summ ~y of its management review, prior to ascension from each power range and prior to normal power operation."

Management reviews for the power ascension test program were documented in three reviews called flag reviews. The first flag review (Flag 2B) was conducted on May 9, 1985, and authorized TMI-1 to proceed with hot functional testing through 48% power. Flag 2B verified plant readiness for testing and was based on an anticipated restart during June 1985. Because of court decisions, restart of TMI-1 was delayed twice. Based on these delays, the licensee updated its Flag 2B approval on August 27, 1985, and on October 2, 1985.

The Flag 3 review was conducted on November 15, 1985 and authorized the plant to proceed from 48% to 100% power. Because of high steam generator levels the plant was only able to achieve 88% power per TP 800/2 on January 2, 1986, the licensee considered the power escalation test program complete. Flag 4 was conducted on January 3, 1986, and the plant was authorized to restart and achieve the maximum power for commercial operation.

On January 6, 1986, the plant achieved 100% power. Further test data were taken after reaching 100% power; however no further flag meetings were required.

The inspector reviewed the summaries of flag meetings and noted that there was a high level of management attention given to these meetings. Each flag review was signed by

the President of GPU Nuclear, five vice presidents, and the chairman of the General Office Review Board. All test data results, including test exceptions and deficien ies, were made available to the NRC Restart Staff shortly after data reduction and review had been completed. All test data were subsequently reviewed by the Test Approval Group (TAG) at formal meetings. The TAG consisted of representatives from Startup and Test, Plant Staff, Nuclear Steam Supply Systems, Technical Functions and Quality Assurance. In addition, most TAG members were supervisory or managerial personnel.

Although a flag meeting was not conducted at 5% power before proceeding to 48%, the staff concludes that the Flag 2B meeting prior to restart and the TAG review of test results at 5%, 15%, 25% and 40% test plateaus meet the license condition. Based on the above review, the inspector determined the licensee review of restart test programs was in conformance with license condition 2.C.(8)3.

4.5.2 Verification of Restart Conditions

4.5.2.1 Restart Condition (2) (d)

Restart condition (2) (d) states that "Prior to completion of the Power Escalation Test program, GPU Nuclear Corporation shall demonstrate safety-grade automatic anticipatory reactor trip on loss of feedwater and upon turbine trip." The reactor trip on loss of feedwater was demonstrated during the trip test per TP 800/2 at 40% power. This was verified by the NRC and documented in NRC Inspection Report 50-289/85-25.

Performance of the reactor trip at 88% power per TP 800/2 on January 2, 1986, demonstrated reactor trip upon turbine trip. Based on the above, the licensee has met the requirements of restart condition (2) (d).

4.5.2.2 Restart Condition (2) (e)

Restart condition (2) (e) states that "Prior to completion of the Power Escalation Test program, GPU Nuclear Corporation shall demonstrate performance of the saturation meter, the incore thermocouples, and the wide range hot leg temperature instrumentation systems installed to recognize inadequate core cooling."

The saturation meter was tested initially in 1981 per TP 645-1, "Test Functional Test," and then retested in 1984 following modification to Class 1E qualified temperature inputs, per TP 700/1, "Controlling Procedure for Low Power

Physics Testing," enclosure 16, "Tsat Margin Comparison." Wide range hot leg temperatures were tested initially in 1981 per TP 657/1, "Non-Nuclear Instrumentation Hot Operation and Calibration," and were retested in 1983 following installation of Class 1E RTDs, per TP 700/1, enclosure 12, "Data Collection Sheets for Modifications '-38, LM-43C and RM-13J." Verification of satisfactory performance and data review for the above tests were accomplished during several previous NRC inspections.

The incore thermocouples were tested during the power escalation test program per TP 846/1, "Incore Thermocouple Functional Test." Verification of final satisfactory performance of this test is detailed in paragraph 4.2.2.4 of this report.

Based on the above, the licensee has met the requirements of restart condition (2) (e).

4.5.2.3 Restart Condition (2)(f)

Restart condition (2)(f) states that "Prior to completion of the Power Escalation Test program, GPU Nuclear Corporation shall demonstrate EFW initiation on loss of all four reactor coolant pumps." Performance of TP 800/9 on January 2, 1986, verified the automatic start of all three EFW pumps upon the loss of all four reactor coolant pumps. This test is discussed in paragraph 4.3.2. Based on this, the licensee has met the requirements of restart condition (2)(f).

4.6 Startup Testing Program Completion

4.6.1 Test Program Summary

The licensee's startup testing program from zero power physics testing to the low power natural circulation test at 3% power was controlled by the test sequence procedure TP 700/1, and power escalation testing was controlled by TP 800/1. The testing program included performance of various tests and was, on a sampling basis, found to be consistent with the FSAR, technical specifications and specific licensee restart condition requirements. The startup testing program was successfully completed on January 2, 1986, following the completion of the 88% power reactor trip test, and with the licensee's subsequent management review.

As described in previous inspection reports (50-289/85-27 and 85-28), the steam generator level versus reactor power tracked higher than expected during the power escalation program, in that it limited the maximum achievable power to about 88%. Unexpectedly, as TMI-1 returned to power

on January 4, 1986, the steam generator water levels no longer imposed an operational limit on the reactor power level. The reactor trip test and the subsequent unplanned trip at 22% power, which occurred during the plant restart on January 4, 1986, apparently resulted in redistribution of deposits in the steam generators. This apparent redistribution allowed the plant to achieve a higher power level. The plant achieved full power operation on January 6, 1986. The licensee conducted additional full power tests that were deferred because only 88% power could be achieved prior to the reactor trip test. Subsequent to this inspection period, the TMI-1 Restart Staff independently reviewed the additional test data and found the test results acceptable.

4.6.2 Overall Test Exceptions and Deficiency (E&D) Review

The licensee startup test and reactor engineering groups have successfully completed the startup testing program. Test results were properly reviewed by the cognizant engineers and/or testing personnel. Final test results were reviewed and approved by Test Approval Group (TAG). All test exceptions and deficiencies have been identified and resolved, and resolutions were acceptable.

4.6.3 Restart Test Program Evaluation

On April 5, 1983, the licensee, by letter, submitted to the NRC a description of its test program following NRC authorization to restart the TMI Unit 1 reactor. The test planning specification (SP-1101-06-008) was attached to this letter and identified the items to be tested; the plant status for testing; the formal commitment for the test; the test scope and acceptance criteria; and the test procedure which would perform the test.

During this inspection, the inspector reviewed the licensee's test planning specification to determine if all commitments identified for the power escalation test (PET) program had been met.

In general, the licensee had met its commitments as defined in the planning specification. However, some discrepancies were noted and are identified below.

4.6.3.1 The test for modification RM-5C, "Containment Isolation on Reactor Trip," requires the verification of proper containment isolation following the 40% and 100% reactor trips and that the override and bypass switches allow valves to reopen. The inspector noted that TP 800/2 failed to document the reset feature of containment isolation valves. The reset feature currently only applies to one valve, MU-V3,

"Letdown Isolation Valve." Resolution of this issue is discussed in paragraph 4.3.1.2.1 of this report.

4.6.3.2 The licensee stated that turbine generator (TG) operation would be tested per TP 885-1. TP 885-1 was to verify acceptability of various TG acceleration, speed and loading parameters and characteristics and to verify proper performance of the TG versus load at (15, 40, 76 and 100% power). A review of TP 885-1 indicates that only steady-state parameters such as temperature, thermocouple performance, and vibration measurements were performed at various power levels.

A licensee representative stated that turbine load testing parameters were tested per a special GE load test performed by GE during hot functional testing. The licensee provided to the inspector documentation of turbine generator load testing, "Control Systems Checkout Prior to Restart," which was performed during the period of October 27, 1981, through December 18, 1981. This testing performed a comprehensive checkout of turbine controls under load conditions.

Based on the above documentation, the inspector considers this test commitment to have been satisfied.

4.6.3.3 Turbine bypass valve testing acceptance criteria in the test specification state that turbine bypass valves shall open in < 3 seconds at < 1100 psia peak pressure. The procedure allows a peak pressure of < 1155 psig. A licensee representative states that pressures were based on startup test, TP 800/6 performed in 1974. TP 800/6 acceptance criteria stated peak OTSG pressure <u>should</u> be ≤ 1100 psia (1085 psig) and <u>shall</u> be < 1180 (1155 psig). These acceptance criteria were not clearly translated into the planning specification.

For the test (TP 885/2) the actual peak pressure recorded by the transient monitor during the 40% and 88% trips did not exceed 1060 psig. Because the main steam safety valves controlled pressure (see paragraph 4.3.1.2.2), the opening times of the turbine bypass valves could not be measured. This is a test deficiency which, when closed, will be resolved by the licensee. Based on the above, the inspector considers that the intent of this test commitment has been met.

6.3 4 The licensee stated that they would perform a natural circulation level control test to determine the lowest level in the OTSG that sustains natural circulation flow while on main feedwater. This was to be performed by TP 800/9 following the reactor trip from (an anticipated) trip at

100% power. This test was to be performed at the request of the licensee's engineering organization.

During the startup test program several weeks prior to the performance of the final trip test per TP 800/2, the licensee notified the NRC Restart Staff verbally that the natural recirculation level control portions of TP 800/9 would be deleted. This was acceptable to the restart staff since this test was to be performed at the licensee's discretion and was not based on any formal regulatory commitment or requirement.

A natural circulation level control test was performed during the natural circulation test at 3% power during performance of TP 700/2. During this test OTSG level was controlled by emergency feedwater and natural circulation was lost at approximately 35% OTSG level on the A steam generator.

Licensee representatives stated that sufficient data were obtained during TP 700/2 because further natural circulation level control testing was unnecessary. Based on the above, the inspector considers that the licensee has met the intent of this commitment.

4.6.3.5 As part of its restart commitment, the licensee stated that after performance of TP 800/8, "RCS Overcooling Control Test," operating procedure (OP) 1102-16, "RCS Natural Circulation Cooling," would be reviewed to ensure that it provides adequate guidance to prevent overcooling during any natural circulation cooling. The inspector questioned whether or not this had been done as this commitment was not part of the test program itself.

Discussions with licensee representatives indicated that the Technical Functions Division located at the corporate office had the lead responsibility for changing this procedure. The inspector reviewed several memoranda by Technical Functions indicating that extensive reviews were being done as result of data obtained from the test. Simulator programs and operator training will be upgraded as a result of data obtained from tests TP 700/2 and TP 800/8. However, these memoranda do not address plant procedures.

The cognizant engineer stated that he was aware of the commitment and was planning to revise OP 1102-16 in the near future. To ensure that this commitment would be tracked, the Manager of TMI-1 Startup and Test, Technical Functions, submitted a technical functions work/task request (TR No. BT 4410), which requests that the results of TP 700/2 and

TP 800/8 be reviewed and that procedural recommendations be incorporated into OP 1102-16. The inspector had no further questions concerning this item.

4.7 Quality Assurance/Quality Control (QA/QC) Interface With the Startup Test Program

Throughout the startup test program, the inspectors observed QA personnel witnessing test performance and reviewing test procedures while in progress. The inspector discussed the test inspection program with QA management, interviewed QA inspectors on shift and reviewed documentation of completed shift monitoring. QA overview of test programs was under the cognizance of the operations QA manager and performed by shift monitoring engineers (SMEs).

SMEs monitor selected activities in the plant and there was at least one SME on shift at all times. During testing, when needed, two SMEs would be assigned to a shift. SMEs are engineering graduates who have qualified for the position. During th test program several QC inspectors were qualified as SMEs in order to augment test program coverage. There was at least one SME assigned exclusively to cover the test program. Rather than perform audits or perform specific inspection points, SMEs performed a monitoring overview. SMEs on a sampling basis reviewed data, verified test procedure compliance, assured that the latest revision of procedures were in use and verified test equipment calibration.

Prior to the start of the test program, the operations QA section developed a detailed monitoring plan. This plan detailed areas to be monitored in each phase of testing, assigned responsibilities, and documented subsequent monitoring by recording QA monitoring report (QAMR) numbers. The inspector noted by documentation of QAMRs that extensive monitoring was done in each area. In addition, the inspector reviewed seven randomly selected QAMRs which were accomplished during different phases of the test program. The QAMRs were comprehensive, in-depth, and indicative of detailed QA inspection coverage.

In addition to tests in progress, QA reviewed all completed test data and exceptions and deficiencies. The operations QA manager is a member of the test acceptance group (TAG). QA has an input to the fi acceptability of test results. As a result of QA participating in TAG, 100% of all completed data is reviewed. In addition to test procedures, QA provided documentation that license conditions, startup conditions, and other regulatory commitments made by GPU Nuclear were being met. Periodic memoranda are forwarded to the Vice President/ Director of TMI-1 concerning the status of GPUN's efforts to satisfy licensing commitments to the NRC.

Based on inspector observations of QA monitoring and extensive documentation of QA monitoring, the inspector considered the monitoring program to be thorough and extensive.

4.8 Conclusions

The nuclear engineering group consistently performed well throughout the entire startup testing period. The physics testing program was well prepared and executed. The test data were properly evaluated and information was disseminated to the appropriate groups. The startup testing group also performed well in coordinating and identifying plant equipment problems. Equipment or procedural problems identified in the early stages of testing were quickly corrected and implemented during the remaining testing period.

Overall, the testing program was effective and provided an adequate test of overall plant equipment performance, plant operator performance, and the ability of safety systems to perform adequately.

5. Event Review

5.1 Reactor Trip/Post-Trip Review

The resident and region-based inspectors attended the licensee's post-trip review of the trips on January 2 and January 4, 1986. This review was required by administrative procedure 1063, "Reactor Trip Review Process." The January 2, 1986, reactor trip review identified several problems that were corrected or appropriate corrective action was initiated by the licensee. Additionally, the review noted that portions of the computer program (transient monitor) used to compute sequence of events did not function. The sequence of events computer program was subsequently retested successfully and the licensee was unable to reproduce the problem. The sequence of events monitor functioned properly during the January 4, 1986, trip, but the licensee decided to closely monitor its function on a daily basis.

The cause of the trip on January 2, 1986, was a manual turbine trip/reactor trip as part of the power escalation test sequence which was described in paragraph 4. The trip on January 4, 1986, was due to failure of the level controller associated with a feedwater heater drain tank which resulted in high level in a moisture separator tank. The moisture separator 1-of-1 instrument logic provided a turbine trip which caused the reactor trip.

For both trips, the inspector independently reviewed the completed enclosure 1, "Post Trip Review of AP 1063," and the recorder strip charts and verified that the data required by enclosure 1 were retrieved with no significant deficiencies noted. The inspector concluded that the procedure adequately evaluated plant performance to the extent necessary to reach a decision related to startup. In addition, the inspector confirmed the licensee's conclusion.

5.2 Radioactive Gas Release from the Waste Gas System

5.2.1 Event Chronology

On December 17, 1985, between 7:40 and 8:00 p.m., an uncontrolled release of radioactive gases occurred in the waste gas compressor cubicle. The plant was at steady-state 75% power and the reactor coolant system was at normal operating temperature and pressure.

Repair personnel were logged in on RWP 31377 to perform preventive maintenance on the 'A' waste gas compressor (WDG-P-1A). The waste gas compressor system was tagged out in accordance with the switching and tagging order. However, a decision was made on December 16, 1985 by the shift supervisor, shift maintenance foreman and radiological controls supervisor to use check valve WDG-V-20 for isolation from the pressurized vent header. Isolation valve WDG-V-100, which is downstream of the check valve, was not closed because preventive maintenance was also being performed on that valve.

A radiological controls technician was assigned to monitor the job. A carboy was used to drain the separator tank so that any releases would be limited to noble gases, as required by the RWP. While draining, an increase was noted on the RM-14 monitor. A local gas sample was obtained, and results indicated the presence of Xe-133 at 3.73 E-7 uCi/cc. No further problems were foreseen, so the job was continued on the basis of these dose rates.

At 7:40 p.m., a strainer was removed from the system and prompted an immediate response on radiation monitors. At 7:45 p.m., monitors RM-A6 (particulate and gas) and RM-A8 (gas) showed increases. The vent header was checked and a small pressure drop was indicated. Steps were taken to stop the job and return the system to a safe condition. At 7:55 p.m., RM-A6 (particulate) was changed out, but the monitor continued to rise. Local gas sampling was taken.

The shift foreman and shift maintenance foreman entered the cubicle to determine how to stop the release as the radiological controls technician was removing the other people from the area. The check valve was determined to be leaking, so the strainer was reinstalled at 8:00 p.m.; this stopped the release.

5.2.2 Scope of Review

The inspectors reviewed the details of the leak and the licensee's review of this event to determine:

-- details regarding the cause of the event and event chronology;

-- consistency of licensee actions with NRC license and procedural requirements; and,

-- licensee actions to correct the cause of the event.

The inspector's review of this incident included discussions with cognizant licensee personnel and review of the following documents:

-- system drawings;

-- CRO and SF logs;

-- switching order 85-1882, dated December 15, 1985;

-- administrative procedure (AP) 1044, "Event Review and Reporting Requirements," Revision 14, dated June 4, 1985;

-- various radiological data and calculations;

-- RWP #31377; and,

-- critique meeting minutes.

The inspectors also attended the radiological investigative critique that was held on December 18, 1985.

5.2.3 Licensee Findings/Actions

The cause of the event was leakage past a check valve that was being used for isolation purposes. Immediate corrective actions were to close the system by reinstalling the strainer into the heat exchanger, and closing valve WDG-V-100, for further isolation.

The RM-A6 (particulate and gas) and RMA-8 (gas) monitors showed maximum increases from 300 cpm to 2000 cpm, 80 cpm to 200 cpm, and 90 cpm to 220 cpm, respectively. These values were below alert setpoints.

A total of eight people were determined to have some amount of contamination, either to skin, clothing, or both mostly due to a short lived noble gas decay. The licensee estimated personnel exposures of about 4E-5 millirems from the incident, which is significantly lower than NRC requirements. The amount released to the environment was estimated to be less than 0.001 percent of the quarterly limit for noble gases.

As part of the licensee's followup actions, this event will be presented to other shifts through the use of the required reading book. A procedure change request will allow WDG-V-100 to be worked on at a more opportune time, when the probability of a release will be reduced. Also, preventive maintenance procedures for gas compressor work will be split up to ensure adequate isolation is provided in the future.

5.2.4 NRC Operational Assessment

Licensee immediate corrective actions during the event were appropriate. Followup corrective actions from the licensee's self-review were also appropriate and reasonably thorough. During and after the event, the licensee followed procedures adequately. However, the inspector concluded that licensee representatives used poor judgement in relying on a check valve for isolation purposes. They should have completed preventive maintenance on WDG-V-100 before or after performing preventive maintenance on the waste gas compressor; therefore, this valve could have been used to isolate the system to preclude the radiological release.

5.2.5 NRC Radiological Assessment

The NRC confirmed the licensee's estimate of activity released to be about 1.4 curies over a 54 minute duration. Offsite exposure due to this event was calculated to be about 1.35 E-3, total dose, based on very conservative assumptions, compared to the licensee's values of 5.2 E-5 mrad gamma and 1.2 E-4 mrad beta, derived from the licensee's offsite dose calculation manual. Licensee action relative to recovery, radiological controls and evaluation of personnel exposure were found to be adequate and in accordance with regulatory requirements. This release constituted less than 0.001% of the quarterly release limit specified in technical specifications.

5.3 Makeup Pump Leak

5.3.1 Event Chronology

At 1:26 a.m., makeup pump 1A was started to supply normal makeup to the reactor coolant system while realigning electrical power to makeup pump 1B. At 1:31 a.m., an auxiliary operator reported slight leakage from mechanical seals on makeup pump 1A and increased radiation activity levels in the makeup pump cubicle. At 1:35 a.m., auxiliary building radiation monitor RM-A6, gas and particulate channels, reached the alert level. At approximately 1:38 a.m., the inboard mechanical seal on makeup pump 1A failed and water

was sprayed onto the walls of the cubicle. The plant operators restarted makeup pump 1B and secured makeup pump 1A. Approximately 300 gallons of water was spilled onto the floor. At 1:42 a.m. the combined fuel handling building and auxiliary building vent radiation monitor RM-A8, gas channel, reached the alert level. Based on the fact that both RM-A6 and RM-A8 were in an alert status, the shift supervisor declared an unusual event at 1:50 a.m.

The shift supervisor directed that makeup pump 1A be isolated and drained. Station health physics personnel began to clean up the room.

Both radiation monitors immediately began to decrease; the RM-A8 alarm cleared at 2:00 a.m. and the RM-A6 alarm cleared at 2:27 a.m. The licensee decided not to secure from the unusual event condition since a planned pump draining evolution had the potential for additional radioactive releases. At 4:00 a.m., makeup pump 1A had been drained and the unusual event was terminated at 4:20 a.m.

As a result of the release, nine people were found to be contaminated. Of the nine, three were found to have actual skin contamination (two on the skin and one on his hair). The two with actual contamination on their skin were decontaminated using soap and water.

5.3.2 Scope of Review

The inspector reviewed the details of the leak and the licensee's review of this event to determine:

-- details regarding the cause of the event and event chronology;

-- consistency of licensee actions with NRC license and procedural requirements; and

-- proposed licensee actions to correct the cause of the event.

The inspector's review of this incident included discussions with cognizant licensee personnel and review of the following documents:

-- systems drawings

-- CRO and SF logs

-- applicable RWP and radiological assessment report

-- critique meeting minutes

5.3.3 Licensee Findings/Actions

The licensee's investigation determined that makeup pump 1A (MU-P-1A) experienced an inboard mechanical seal failure. The seal failure resulted from a loose thrust bearing lock-nut. This resulted in the loss of the thrust bearings function, allowing the pump shaft to move axially and to cause the seal failure. The locknut had been secured with a set screw, which had loosened allowing the locknut to subsequently loosen. In order to prevent a recurrence of this failure, the licensee dimpled the shaft at the location of the set screw and applied "Locktite" (permatex sealant) to the shaft and set screw. Radiological releases were within regulatory requirements.

5.3.4 NRC Operational Assessment

Review of licensee actions during the event were found to be appropriate and proper use of procedures was noted. The root cause was appropriately determined to be a failed mechanical seal caused by a makeup pump thrust bearing shift.

The inspector reviewed the engineering evaluation for the dimpling of the shaft and the application of the sealant. Also, the actual work that implemented the modification was witnessed. The work was found to be adequately controlled, supervised, and performed by experienced and knowledgeable workers. Quality control personnel also observed the work. One minor problem arose with regard to the use of Permatex sealant on the thrust bearing housing cap and end plate joints. All three pumps had previously been sealed with Permatex in these areas. During reassembly of the 1A pump, the use of Permatex sealant was not approved by QC; and, therefore, it subsequently leaked minutely during testing. The 1B and 1C pumps were made up using an approved sealant. The licensee will review the tasks that used Permatex to determine if it is acceptable. Following the completion of the modification, all three pumps were tested prior to being declared operable. The inspector had no further questions with regard to this matter.

During observation of the work being performed on MU-P-1A, it was noted that the installed thrust bearing locknut was made of brass, while the vendor's manual for the pump specified the thrust bearing locknut to be steel (SAE 1020). The licensee contacted the vendor and determined that four

replacement locknuts made of brass, instead of steel as ordered in 1974, had been mistakenly shipped. This was attributed to human error in reading the equipment material list; brass is the specified material for the item directly below the locknut on the material list. The locknuts installed on MU-P-1B and 1C were verified to be made of steel.

An engineering evaluation was performed to justify the use of a brass locknut on the 1A pump. This evaluation used the pump manufacturer's calculations using worst case axial thrust loads; the evaluation showed that the brass locknut would not be subjected to shear failure of its threads. The brass locknut will be replaced with a steel locknut at the earliest convenient opportunity.

From the licensee's operational and engineering review, the root cause was identified and corrective actions were appropriate.

5.3.5 NRC Radiological Assessment

Analyses of the event indicated that the predominant radiological contributor was noble gas activity; i.e., radioactive krypton and xenon gas. As a result, about nine people in the auxiliary building were contaminated with particulate noble gas decay daughters; i.e., Rb-88 and Cs-138, which caused negligible exposure. Workers involved in recovery and clean-up operations received less than 50 mrem exposure for the event.

The spray caused a spill of about 300 gallons of reactor coolant which was collected via the floor drain system in the auxiliary building sump. Off-gasing of the noble gas constituents during the event resulted in release of noble gas activity through the station vent for about 74 minutes. Evaluation of the vent monitors indicated that about 46 curies of noble gas activity, principally Xe-133, were released. Off-site dose consequences of this release were calculated to be 3.69 E-3 mrad gamma and 5.97 E-3 mrad beta at the site boundary. Such exposure constitutes 0.07% of the quarterly limit permitted by the license technical specifications; i.e., 5 mrad gamma air dose and 10 mrad beta air dose. These values were independently confirmed by the NRC inspector.

The licensee's followup and review of the occurrence was thorough and timely. Radiological control coverage was sufficient to rapidly identify the hazard and minimize personnel exposure. The licensee's critique of the event identified areas in which response should be improved and action was initiated to implement lessons learned.

No conditions adverse to regulatory requirements were identified in this area.

5.4 Conclusion

Operators were responsive to these events with respect to isolating the radiological release and/or following appropriate plant and emergency procedures. The licensee's event review or critique was thorough enough to identify the root cause of the events. Appropriate corrective action was taken or planned. Licensee dose calculations were conservative and independently verified by the TMI-1 Restart Staff.

6. Radiation Protection

6.1 Radiological Program Area Review

The licensee's program was reviewed against, (1) criteria contained in 10 CFR 20 relative to personnel exposure control and radiological surveillance, (2) applicable license conditions relative to internal audits and assessments and procedure establishment and implementation, and (3) personnel qualification and training. Additionally, management controls were reviewed.

Adequate procedures and protocols are established and implemented to control personnel exposure both in-plant and offsite. The licensee is consistently conservative with regard to dose assessments, and generally exercises good judgement in analyzing and assessing events which have the potential to cause increased exposure.

Internal audits for the 1985 period were reviewed relative to the Radiation Protection Plan. The audits were conducted by qualified personnel and exhibited sufficient technical depth to evaluate program performance. Though most audit findings identified in this period were administrative in nature, sufficient technical insight was demonstrated.

However, while this particular audit process is formalized and carried out in accordance with schedules, there is no assurance that all program areas will receive sufficient review, since the audit scope is not tracked. Rather, a general audit assignment is made and the

individual auditors decide on the scope and depth of the assessment, with management approval. There is no system currently in place that tracks audits of individual program elements that can be utilized to verify that the entire program as defined by the Radiation Protection Plan is subject to periodic critical review. This item will be reviewed in a subsequent inspection (289/85-30-03).

Radiological surveys are performed thoroughly with sufficient detail to support radiological work. Current surveys are conspicuously posted at the control point to support worker briefings and at individual radiologically controlled areas as a reference to actual conditions.

Personnel exposure control practices involving RWP usage appeared sufficient to prohibit inadvertent, unanticipated or unplanned personnel exposure, provided personnel conform to established policies and procedures. During this inspection, the licensee identified that an individual inadvertently entered an area requiring an RWP without such authorization, due to misplaced area posting. Immediate and adequate action was taken to assure that the area was adequately controlled and exposure to the individual assessed. In this event, the individual received less than 10 millirem due to the occurrence. The licensee initiated action to prevent recurrence. Though technically a violation of technical specification 6.13, "High Radiation Areas," this event meets all of the criteria for licensee identified events specified in 10 CFR 2, Appendix C, and will not be cited.

The licensee's training and qualification program was reviewed and appears sufficient to assure competency and technical proficiency among radiation protection personnel. While actual operating experience is limited in the department, sufficient management oversight and control is exercised in an effort to compensate.

Management personnel demonstrate a high degree of involvement and understanding of plant conditions, communicate effectively internally and inter-departmentally, and appear to plan, organize and direct effectively.

No conditions adverse to regulatory requirements were found in any of the areas reviewed.

6.2 Control of Work Activities

The licensee's program for controlling work activities and worker exposure was evaluated by interviews with selected members of the radiation protection staff, and review of the following documents and procedures.

-- procedure 9100-ADM-4110.04, "Radiation Work Permit"

-- RWP # 31259, "Remove FS Detector 8-2 from Service," and associated ALARA review

-- RWP # 031201, "Change MUF 2A&B and MUF 1A&B," and associated ALARA review

-- RWP # 031202, "Decon Letdown Prefilter Cubicle and Hallway"

-- RWP # 031204, "Remove Broken Filter from Letdown Filter Room"

-- selected radiological surveys associated with the above RWP packages

-- selected RWP signature verification and entry-exit times

-- the health physics air sampling log book

The licensee's radiation work permit (RWP) system specifies radiological controls for specific and routine work activities in radiological areas. The inspector reviewed the RWPs mentioned above, along with selected associated documentation and determined that:

-- radiological surveys used in the development of RWPs were generally of sufficient depth and scope;

-- radiological controls outlined in the RWPs were appropriate for the work being performed;

-- administrative requirements of the controlling RWP procedure (HP supervisory review, pre-work briefings, etc.) were being complied with;

-- air sampling was performed as required by various RWPs; and,

-- workers wearing respiratory protection on selected RWPs had received required respiratory protection training and fit-testing.

Overall licensee control of work activities and worker exposure was found to be adequate. The inspector noted the licensee's method of choice for job specific air sampling is to provide lapel air samplers to the work parties. This ensures a representative breathing zone air sample is collected and used to calculate MPC hours.

6.3 Posting and Area Control

The licensee's posting and control of airborne radioactivity areas, contaminated areas, and radiation and high radiation areas was reviewed with respect to the following criteria.

-- Technical Specification 6.12, "High Radiation Area"

-- 10 CFR 20, "Standards for Protection Against Radiation"

The licensee's performance in this area was reviewed by the following methods:

-- inspector tours of the various radiological work and storage areas

-- performance of independent surveys by the inspector

-- interviews of radiation protection supervisory and technician-level personnel

Housekeeping in the licensee's radiological areas was generally good. The inspector noted the licensee has implemented the guidance contained in NRC IE Notice No. 84-82, "Guidance for Posting Radiation Areas," in that posting has in general been limited to small, discrete areas around the radioactive source, rather than simply posting at cubicle doorways. This effort by the licensee to minimize over posting helps prevent worker desensitization to radiological posting.

This inspection effort included tours of the auxiliary building and independent survey verification of licensee radiological boundaries. The inspector noted during a survey of the mini-valve alley on the 286 foot elevation that a high radiation area posting inside the cubicle was not appropriate. A "high radiation area" sign and posting is required to indicate the presence of a high radiation area, i.e. an area where radiation dose-rates exceed 100 mrem/hr. Consequently, the boundary and posting for the high radiation area should be located outside the area, where dose-rates are less than or at 100 mrem/hr, to alert personnel.

The inspector determined that the radiation field inside the cubicle was non-uniform and that while the licensee's boundary was adequately placed when dose-rate measurements were made at waist level, dose-rates greater than 100 mrem/hr could be measured outside the high radiation area boundary at the head level.

Immediately the licensee satisfactorily reposted the cubicle when informed of the inspector's findings. Subsequent surveys in the cubicle and comparison with previous routine surveys indicated that dose-rate conditions had changed in the cubicle in the interval between the last licensee survey and the inspector survey in the cubicle.

The licensee indicated that HP technicians are instructed to make "general area" dose rate measurements by recording the highest waist-level dose reading in a 360 inch circle. The licensee indicated some technicians may have extended this technique to the posting of radiation and high radiation areas, using waist-level dose rate

readings. The licensee indicated that technicians would be notified as to the posting problem indicated above and the need to survey for dose to the whole body and post accordingly. Licensee followup action will be reviewed during a subsequent inspection (289/85-30-04).

Within the scope of the above review, no conditions adverse to regulatory requirements were identified.

6.4 Recurrence of Noble Gas Contamination of Personnel

During this review it was noted that occurrences involving the use of the auxiliary building floor and equipment drain system to direct reactor coolant runoff to the auxiliary building sump often result in personnel contamination. Such contamination is due to the shortlived particulate daughters of the noble gases Xe-138 and Kr-88; i.e., Cs-138 and Rb-88, respectively.

While individual exposure to this type of contamination is generally not significant due to the short decay period of Cs-138 and Rb-88, the recurrence of events in which large portions of the auxiliary and fuel handling buildings are affected by noble gas activity is not normal to the operation of the facility.

In an effort to understand the conditions that cause extensive noble gas migration in the auxiliary and fuel handling building, the licensee initiated actions to test floor and equipment drain systems. As a result, a drain header has been recently identified as being a primary conduit of noble gas through the auxiliary building and into the TMI-2 portion of the fuel handling building.

In an effort to restrict and control this pathway, suspect drains were either incorporated into the loop seal surveillance program, sealed or covered. Additionally, action has been initiated to detect and seal major leakage points through the Unit 1/Unit 2 environmental barrier. These efforts should prevent the spread of Unit 1 airborne activity to Unit 2. However, noble gas involvement of large portions of the auxiliary building due to localized activities such as flushing operations, reactor coolant sampling, and component leakage, is still not under control and results in the frequent contamination of several personnel.

Though the licensee is investigating various mechanisms that may be responsible for this problem, there is no concerted or organized effort yet developed to assure the timely completion of investigative action items, the analyses of results, and the development of an effective resolution.

This item will be reviewed in a subsequent inspection and is currently being followed by NRC staff (289/84-16-01).

7. Emergency Feedwater Pump (EF-P1) Operability

7.1 Review

The inspector assessed the operability of the turbine-driven emergency feedwater pump based on a review of licensee maintenance (preventive and corrective) and surveillance activities to verify that:

-- procedures required by Technical Specifications (TS) 4.2.2 and 4.2.1.1 are being properly implemented;

-- applicable procedures have the proper format and technical content in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWP, and applicable sections of ANSI N18.7-1976;

-- surveillances and preventive maintenance (PM) were conducted at the proper frequency; and,

-- machinery history records and related surveillance and PM records were retrievable.

In addition to discussions with cognizant licensee personnel (maintenance, operation, and engineering), the inspector reviewed selected portions of the following licensee documents and records:

-- surveillance procedure (SP) 1300-3G A/B, "Turbine Driven Emergency Feedwater Pump Functional Test and Valve Operability Test," Revision 20, dated November 13, 1985, including data obtained on December 11, 1985, November 13, 1985, October 13, 1985, and September 15, 1985;

-- PM procedure 1410-P-3, "Lube Oil Change," Revision 6, dated February 2, 1985;

-- selected job tickets from machinery history files, numbers CB969, CE756, CF763, and CH760 between the period of January 1, 1973 to November 5, 1985; and,

-- Worthington Pump International Technical Manual 2134-EIC, "WT Pumps" and Technical Manual W-9C, "Turbine."

7.2 Findings

On December 16, 1985, EF-P1 was out of service to test a new governor valve controller. This controller was being tested to determine if it would prevent the relief valves on the steam line to the EF-P1 turbine from lifting during the start sequence and if it could adequately control EF-P1 during operation. The inspector reviewed tagging order 85-1881 that was used to place EF-P1 out of service. The inspector determined that appropriate valves were tagged locally and in the control room and appropriate breakers were opened.

While the licensee was testing the new controller, the inspector observed good work practices, except for two instances when workers used the limitorque operator for MS-V-10B as a stepping point. During testing, the controller did not perform satisfactorily and the licensee replaced the new controller with the old controller. In order to return EF-P1 back to service, SP 1300 3G A/B was used. The inspector reviewed this package and no discrepancies were noted.

The review of machinery history on EF-P1 revealed no major problems over the last twelve years, except for a bearing replacement during the spring of 1985. This history file provided a useful summary of work activities on the turbine-driven EFW pump. The job ticket records were retrievable using the licensee's microfiche and microfilm systems.

Preventive maintenance procedures appropriately reflected vendor recommendations to change lubricating fluids at six-month intervals on both the pump and turbine. The pump manual also recommended that the pump should not be routinely disassembled; this should only be performed when there is a problem with the pump. The licensee is planning to follow this recommendation.

Surveillance and preventive maintenance procedures were current and being conducted at the proper frequency in accordance with technical specifications. The records of these tests were retrievable. SP 1300 3G A/B was found to meet all applicable requirements of Subsection IWP, Section XI of the ASME Code.

7.3 Conclusions

The inspector concluded that the licensee properly tagged out of service EF-P1 and appropriately returned it to service. Licensee records were well kept and reflected applicable procedures that were being properly implemented. The licensee is continuing to follow the recurring problem with the EF-P1 steam relief valves. Pending satisfactory resolution of this issue, in-place surveillance and preventive maintenance procedures should provide adequate reliability that the turbine-driven emergency feedwater pump will be operable when needed.

8. Non-Licensed Staff Training

8.1 General

The purpose of this portion of the inspection was to assess the effectiveness of the licensee's non-licensed training. As a representative sample, the inspectors chose the training programs for instrumentation and control (I&C) technicians, electrical and mechanical maintenance personnel, and auxiliary operators (AOs). The inspectors noted that the licensee is in the process of obtaining INPO

accreditation for these training programs. The effectiveness of the existing program was determined by reviewing the following activities:

-- monthly reactor protection system surveillance by the I&C technicians

-- shift turnover for AOs (0700 twice, 1500 twice, 2300 twice)

-- corrective maintenance (CM) for hydrogen analyzer by I&C technicians (CM-1430-HA-2, paragraph 6.10)

-- AO activities on all three shift (changing over the hydrogen supply to the makeup tank and taking secondary plant readings)

-- minor maintenance by mechanical maintenance personnel (maintenance of leaking valves in accordance with CF 498)

-- vibration test on main steam drain pipe by electrical maintenance staff

-- repair work on water screen

-- troubleshooting for the AH-E-12 fans circulating systems (preliminary action to determine if a CM or a work order (WO) is required)

-- welding activities (DF 2A&B piping in accordance with WO-C-7409)

These activities were selected from day, evening, and midnight shifts.

The problems associated with the power operated relief valve (PORV) surveillance on October 25, 1985, was used as an example of personnel error.

8.2 Details of the Review

For each of the job functions identified in Section 8.1, the inspectors reviewed the established training program, implementing procedures, qualification, and experience of personnel, qualification and training of instructors, quality of on-the-job training, and the effectiveness of training as evidenced in daily activities. The comments and evaluations from the trainees, line supervisors, and instructors were also reviewed to establish how this feedback was factored into future training. Lessons learned from the events at the licensee's facilities, as well as other facilities, were also reviewed to determine how such information was factored into the training program. The management and QA involvement in the training area was assessed to determine their effectiveness. No violations were identified. The observations in each of the review areas are given below.

8.2.1 Observation of Work Activities

The inspectors witnessed the work activities identified in Section 8.1 above. The activities were conducted in accordance with the procedures. The personnel were knowledgeable in the requirements of the procedures and technical specifications. Experienced personnel were providing adequate guidance to inexperienced personnel. All of the activities witnessed were conducted satisfactorily.

Two situations, the monthly reactor protection system surveillance and the followup of the PORV surveillance error, are discussed in detail. For the reactor protection system surveillance, the inspector witnessed the interaction between experienced and inexperienced personnel. The experienced technician read the procedure requirement and the inexperienced technician performed the action. Adequate time was provided to the inexperienced technician to conduct the action. The experienced technician was patient to let the inexperienced technician learn from his mistakes. For example, while performing step 8.5.14 of procedure 1303-4.1 (revision 47), the inexperienced technician connected the digital voltmeter to the test jack of the auxiliary power supply instead of the power range detector power supply. The inexperienced technician sensed a concern when he had to over adjust to bring the output within tolerance. At this juncture, the experienced technician stopped the procedure and initiated the investigation. The foreman brought the lead foreman to the work area to provide further assistance. In step 8.8.8 of the same procedure, the technicians noted that the pressure/temperature bistable trips were not within tolerances. In this case, the I&C supervisor came to the work area and assisted the personnel in identifying and correcting the concern. The problem was caused by an above-normal zero/gain setting on the signal converter. The problem was corrected and the supervisor instructed the technician to monitor the output from the signal converter carefully for potential problems in the future.

The inspectors also reviewed the actions undertaken by the I&C group to preclude the problems developed during and after the PORV surveillance test described in paragraph 8.1 above. The maintenance department issued a verbal order to require that all technical specification related surveillances are to be conducted by senior personnel. The inspectors reviewed the log for monthly surveillances of RPS channels. Since October 25, 1985, these surveillances were conducted by senior personnel. The inspectors found the activities to be conducted in a competent manner by qualified and properly trained personnel.

8.2.2 Training Policy and Programs

Procedure 1000-POL-2600.01, Revision 0-00, dated April 15, 1985, established the licensee's training policy. This policy stresses items such as the basis for training, commitment to training, on-the-job performance, and effectiveness. It also established the role of the Training Advisory Council and the commitment to pursue and maintain INPO accreditation. This policy is implemented through system-wide procedures. The inspectors reviewed the implementing procedures listed below as a representative sample.

Documents Reviewed

Number	Title	Revision	Date
6211-PGD-2612.01	Auxiliary Operator Training Program TMI-1	5-00	8/1/85
6210-ADM-2621.01	Maintenance Training Program TMI-1/TMI-2	3-00	7/20/84
6210-ADM-2621.02	Maintenance Training Instructor Certification/Qualification Training Program	2-00	10/24/84
6210-ADM-2621.03	Maintenance Indoctrination Training Program TMI-1 and TMI-2	1-00	5/17/85
6210-ADM-2604.03	Control of Examinations Units 1/2	0-00	3/1/85
6210-ADM-2620.01	Revision Review/Required Reading Book for Technicians and Support Training Instruction	3-00	11/1/85
6210-ADM-2610.02	Operator Training Instructor Indoctrination/Qualification Training Program	01	8/23/82
6200-ADM-2682-09	Standard Evaluation While In Training	0-00	4/15/85
6200-ADM-2682-10	Trainee Evaluation Once Back On-The-Job	1-00	9/13/85
6200-ADM-2682-11	Program Evaluation	0-00	4/15/85
6200-ADM-2682-12	Course Evaluation	0-00	4/15/85

Maintenance Department Standing Orders Nos. 17 and 18

The training for non-licensed personnel consists of both formal and on-the-job training. The formal training is provided at the training facility and the laboratory. It includes discussions of theory, hands-on operation, and maintenance of generic components such as pumps and valves. At present, the formal training is conducted in classes containing all levels of personnel. The instructors prepare the lessons for the persons with average experience. As a result, the formal training tends to be boring for senior staff and difficult for the entry-level personnel as determined through inspector interviews. This is identified as an area of concern by both the instructors and trainees. The licensee's self evaluation report identified similar problems.

Training and development educational procedures and job descriptions for instructors of various grade levels are developed by the Corporate Human Resources Department. The inspector reviewed the training and qualification records of the maintenance and AO instructors. The instructors' files were complete and current. The files contained evaluations by peers, supervisors, managers, and Corporate specialists. The inspector reviewed the evaluations by the students and noted that the comments are reviewed and corrective action is taken. In one case the instructor received additional training in a specific area.

The inspector reviewed the AO Crew Required Reading Book index. The AOs signed off that they have read items such as IE Notices, significant events at TMI-1 and INPO reports.

An Operator Training Work Request form is submitted by personnel requesting additional, modified or new training. Request form 84-01 regarding additional limitorque valve training was submitted by an AO; he is now being trained in response to his submittal.

The training program for non-licensed personnel is expected to change considerably in the future due to INPO accreditation and an automatic mode of progression for technicians and maintenance personnel. The automatic mode of progression is in effect for I&C personnel. However, the electrical and mechanical maintenance personnel have not ratified this option in the union contract. This option will be considered for union ratification in the Spring of 1986.

The licensee has completed the I&C job and task analysis required for the INPO accreditation. This analysis was done by an outside contractor. An on-the-job training program was being drafted at the time of this inspection. The licensee has completed a self evaluation in the I&C area

and the report was being drafted for submittal to INPO. The inspector reviewed the licensee's activities and determined that the licensee is progressing towards INPO accreditation. The licensee intends to resolve all concerns identified in the self evaluation report by March 1, 1986.

8.2.3 Training Audits and Evaluations

In addition to direct observation of the effectiveness of training through the conduct of work, the inspectors interviewed at least one experienced and one inexperienced person from each work group for each shift. The interviewees were complementary to the training program and instructors. The inspectors discussed student and industry experience feedback with instructors. The instructors went over the lesson plans with the inspectors and demonstrated the depth of preparation. In new areas, the instructors spent up to eighteen hours of preparation for one contact hour of classroom instruction. The instructors also demonstrated that the comments from trainees and line supervisors were incorporated in the lesson plans in a timely manner. The instructors provided specific lesson plans to show how they incorporated industry experience gathered from NRC bulletins and INPO documents in such lesson plans.

The quality assurance staff conducts routine audits in training and review of the effectiveness in audits for maintenance. The inspector reviewed QA audit reports S-TMI-85-04 (Training) and S-TMI-84-01 (Maintenance) and noted that these audits were indepth and technically oriented. QA personnel demonstrated good knowledge in the requirements of non-licensed training and industry practices for maintenance and calibration. In addition to the audits, QA monitors the training and the activities conducted by trained personnel. The findings from the audits and monitorings are forwarded to various levels of management for actions and feedback. The findings are also trended regularly to identify and correct potential problems.

The line supervisors actively participated in training efforts. Annual training requests were provided to the training personnel in a timely manner. Managers and supervisors monitored the quality of instruction through occasional class attendance. Some line supervisors expressed reservations when instructors signed-off practical factors for technicians and mechanics.

The inspectors noted that several practical factors for maintenance personnel were signed off by the on-the-job training (OJT) coordinator on the same day. In discussions

with the trainees and OJT coordinators, the inspector learned that the date used does not necessarily imply that the specific practical factor was conducted on that day. Certain practical factors go on for weeks under the OJT coordinator's cognizance. The date signed merely indicates that the OJT coordinator reviewed the effort on that day in accordance with Maintenance Department Order No. 17. This order allows for the coordinator's evaluation of those individuals who attained the required skill level through previous experience. The coordinators and the trainees indicated that the existing practical factors records do not always adequately reflect the extent of training received. The inspector reviewed several practical factors. In the mechanical area, it is possible to complete several practical factors on the same day. In the electrical area, when the practical factors were signed off on the basis of previous work experience, it was not always possible for the trainee or the coordinator to recall the job ticket number or the component designators used for such sign-offs. This was discussed in detail with licensee representatives and they acknowledged the inspector's observation. The adequacy of the records for on-the-job training will be reviewed in a future NRC inspection (289/85-30-05).

8.3 Conclusions

Within the scope of this inspection, the licensee's training program was effective and is geared to improve on-the-job performance with management support and commitment. QA is actively involved in training. The personnel were knowledgeable in the work and procedural requirements and conducted the activities with care. When faced with problems, the personnel demonstrated the ability to take conservative measures and seek help. In brief, with the exception of certain records-related problems and licensee identified areas of concern, overall, the non-licensed training program was implemented and maintained in accordance with license requirements and applicable industry standards.

9. Startup to Power Operation Review

During the inspection period, the staff reviewed selected portions of the licensee's maintenance and surveillance and startup testing programs to assess the readiness of the plant for startup and release from the final power escalation test hold point. The selected areas inspected included outstanding licensee identified items in the surveillance, maintenance and startup test areas. The objective was to identify equipment operability problems that could adversely affect safe operations of the facility. The startup testing area was reviewed as documented in paragraph 4.

The inspector reviewed selected portions of the licensee's applicable corrective action tracking systems to determine if any adverse condition for safety-related equipment operability existed. The inspector's review included tracking systems for open maintenance job tickets. The inspector reviewed the open job tickets and discussed all work that had been classified as priority one, two, and three. Of the priority one, two, and three work, the inspector determined that the work required by these jobs would not have an adverse affect on the plant safety if not performed prior to returning the plant to operations.

Also, the licensee maintains a system for E&Ds associated with surveillance test procedures in order to identify and track procedure and hardware problems identified during performance of the tests. The surveillance test coordinator (STC) has placed a summary of unresolved E&Ds on a computer system and periodically reviews a computer printout to ensure that E&Ds are ultimately resolved.

Prior to the restart of the reactor subsequent to the turbine trip test, the inspector requested a computer printout of open surveillance test E&Ds. The inspector along with the STC and an operations engineer reviewed each item listed on the printout. No open test exceptions or deficiencies were identified on the computer printout which would have precluded restart of the plant.

The inspector asked whether outstanding E&Ds were routinely reviewed prior to any reactor startup. The operations engineer stated that enclosure 1, "Plant Critical Check List (Shutdown greater than 24 hours)," and enclosure 2, "Plant Critical Check List (Shutdown less than 24 hours)," to operating procedure 1102-2, "Plant Startup," require the verification of the adequate performance of numerous surveillance tests. As each test is verified, each exception or deficiency which is unresolved must be reviewed to assure that surveillance acceptability is not affected. The inspector reviewed enclosures 1 and 2 to procedure 1102-2 and observed the verification of surveillance tests and had no further questions concerning this area. There were no E&Ds open that would preclude startup after the turbine trip test.

10. Steam Generator Mechanical Cleaning

Between January 7-9, 1986, TMI-1 Restart Staff inspectors observed the water slap process demonstration and test program at Lynchburg, Virginia, with the objective of understanding the process and familiarizing themselves with the test program. The water slap process involves accelerating a column of water toward a tube support plate at a velocity sufficient to dislodge accumulated scale or corrosion products from the spaces between tube and support plate surfaces. The test program was to establish that the steam generator integrity would not be compromised by process damage to components such as tubes, tie rods, tube support plates, and tube-to-tube sheet attachments. The testing included multiple applications of the

process to a full scale mockup up to the fourth support plate. Process transients such as pressure, stress and tube or tube support acceleration were measured.

From these measurements, stress values of components were established for comparison to the ASME Code, Section III, NB, 1983 edition. The testing conducted to date indicates that stress values are significantly below the ASME code allowable levels. The testing and evaluation of data are expected to be finalized by late February 1986 and documented in a safety evaluation.

The NRC inspectors observed testing in progress, examined equipment in use and reviewed portions of previous safety evaluations that were applicable to use of a similar process. The test program was performed with calibrated sensors and equipment and was noted to be carefully planned and performed.

Discussions with utility personnel indicated that the process was successful when previously used.

11. Licensee Action on Previous Inspection Findings

The inspector reviewed licensee action on previous inspection findings to ensure that the licensee took appropriate action in response to the findings or by self-initiative, and that the licensee's action was timely.

11.1 (Open) Inspector Follow Item (289/83-26-03): Temperature effects on RM-L10. Since a question still remains relative to temperature effect on RM-L10 the licensee has taken or will take the following actions:

- The RM-L10 set point has been reduced by 10% to compensate for the expected decreased performance of the detector with increasing sump temperatures.

- A work order has been initiated to modify RM-L10 with a thermometer device that will cause increased voltage as a function of temperature to automatically compensate for decreased efficiency; such modification will be made pending the success of testing by the vendor.

- Procedural modifications are being considered relative to taking RM-L10 out of service in favor of composite sampling when the reactor is shutdown and the auxiliary boiler is expected to discharge to the turbine building sump.

Operational data so far indicates that turbine building sump temperatures may not exceed the design specification for the detector. The licensee will continue further monitoring of the system.

11.2 (Closed) Inspector Follow Item (289/84-18-01): Licensee to review the applicability of using pressurizer uncompensated water level in the reactor coolant system leakage calculation. The licensee completed that review and decided not to use the uncompensated pressurizer water level signal in the computer calculation for reactor coolant system leakage. The licensee determined that the gain in accuracy was only 0.05 gpm and, accordingly, this gain in accuracy did not warrant major procedural and software changes.

Since the use of compensate water level introduces only a $\pm$ 0.1 gpm error in the calculation, the inspector considered the licensee's leak rate calculation is acceptable.

11.3 (Open) Inspector Follow Item (289/84-18-02): NRC staff to review applicability of the evaporator loss term in the reactor coolant system leak rate calculation. By internal memorandum, the Office of Nuclear Reactor Regulation advised Region I that the evaporative loss term should either be recalculated to a new baseline number or deleted since the current value introduced a negative unidentified leak rate which was unrealistic. Concurrent with that determination, the licensee decided that a readjustment of the evaporative loss term was appropriate. A licensee procedure change was reviewed and approved to incorporate the licensee's decision in this matter but the computer program revision still need work. The licensee committed to revise the evaporative loss term to zero and to implement necessary procedural and software changes by January 31, 1986.

11.4 (Open) Unresolved Item (289/85-19-02): Licensee to review steam generator primary to secondary leak rate actions to factor in experience gained as a result of the power escalation program. Based on TMI-1 staff review, the leakrate calculation was relatively stable despite transients on the plant. It appears that the limit for shutdown 6 gph (gallons per hour) above baseline (0.5 gph) is realistic. However, current procedural actions call for extended evaluation of the leakrate for 6-12 gph above baseline. This extended evaluation period appears to be no longer necessary. The licensee committed to review this matter and issue appropriate procedure revisions by April 1, 1986.

11.5 (Open) Unresolved Item (289/85-22-02): Licensee to resolve problem with steam relief valve actuation upon initiation of the turbine driven emergency feedwater pump. Details of licensee actions are discussed in paragraph 4.3.2.2. The licensee is committed to provide a fully automatic emergency feedwater initiation system by the startup after the next refueling outage (approximately April 1987).

11.6 (Open) Unresolved Item (289/85-25-05): Licensee to resolve problem with continuous actuation of steam generator safety valve on high power reactor trips. Details of licensee actions are discussed in paragraph 4.3.1.2.2. The licensee committed to having a plan for corrective action and implementation schedule by the end of the eddy current outage (approximately April 1986).

11.7 (Open) Unresolved Item (289/85-25-06): Licensee to review and provide a response letter to NRC Inspection Report 50-289/85-25 with respect to the discarding of a test exception and deficiency record. The licensee committed to provide the response letter by January 31, 1986.

11.8 (Closed) Unresolved Item (289/85-26-04): NRC staff to review licensee assessment relative to dose effects of leakage from makeup pump (MU-P) 1A. The licensee has completed investigation of anomalous releases due to problems encountered in the maintenance and operation of MU-P1A. The following occurrences were reviewed and found to be acceptably evaluated.

Date	Event	Activity Released	Fraction of Quality Limit
10/28/85	Maintenance problem causing 150 gal. spill	0.7 Ci	0.0086%
12/30/85	Operation problem causing 300 gal. spill	46.3 Ci	0.07%

Additional details in this report relative to recurrence of noble gas contamination are in paragraph 6.

11.9 (Closed) Unresolved Item (289/85-27-02): Licensee to evaluate high steam generator water level limit with respect to decreased heat transfer efficiency. The TMI-1 Restart Staff review of licensee action is documented in NRC Inspection Report 50-289/85-28 but this item number was inadvertently missed from being closed. It is addressed in this report for administrative purposes although the high limit is no longer currently needed (see paragraph 4.2.2.1).

11.10 (Open) Inspector Follow Item (289/84-16-01): Licensee to balance auxiliary/fuel handling building ventilation. Based on a review of radiological incidents (paragraph 4) it appears that the leaving of the ventilation system in an unbalanced condition has contributed to the spread of noble gas out of potentially contaminated or contaminated areas resulting in short-lived daughter product contamination of personnel. Additional details are in paragraph 6.4.

12. Exit Interview

The inspectors discussed the inspection scope and findings with licensee management at a final exit interview conducted on January 10, 1986. In addition to the testing program status meeting of December 17, 1985, interim exit interviews occurred on: December 20 1985 (Non-licensed training); January 8, 1986 (Startup Test Program); and January 9, 1986

(Radiation Protection). The following licensee personnel attended the final exit meeting:

J. Colitz, Plant Engineering Director, TMI-1
T. Hawkins, Manager, Startup and Test, Technical Functions
H. Hukill, Director and Vice President, TMI-1
C. Incorvati, TMI-1 Audit Supervisor, Nuclear Assurance
B. Leonard, Operations Training Manager
R. Masoero, Engineer, Plant Analysis
R. Neidig, TMI-1 Communications
M. Nelson, TMI-1 Review Program Supervisor
S. Otto, TMI-1 Licensing Engineer
L. Ritter, Administrator II, Plant Operations, TMI-1
M. Ross, Manager, Plant Operations, TMI-1
D. Shovlin, Manager, Plant Maintenance, TMI-1
P. Sinegar, Administrator II, Manager, Maintenance
M. Snyder, Preventive Maintenance Manager
C. Smyth, TMI-1 Licensing Manager
R. Toole, Operations and Maintenance Director, TMI-1

The exit meeting was also attended by S. Maingi, a nuclear engineer representing the Commonwealth of Pennsylvania. The inspection results, as discussed at the meeting, are summarized in the cover page of the inspection report. Licensee representatives indicated that none of the subjects discussed contained proprietary information.

Unresolved Items are matters about which information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved item(s), discussed during the exit meeting, are documented in paragraphs 2.2.4, 4.3.1.2.2, 4.3.2.2, 6.4 and 11.

Inspector Follow Items are matters which were established to administratively follow open issues based on inspector judgement or on licensee/staff commitments prior to the TMI-1 restart. Inspector follow item(s), discussed during the exit meeting, are documented in paragraphs 6.1, 6.3, 8.2.3 and 11.

ATTACHMENT 1

Startup and Testing Meeting
December 17, 1985 - 2:00 p.m.

Licensee:

W. Bloomfield, Nuclear Safety Engineer (IOSRG)
J. Carroll, Jr., TMI-1 Startup and Test Director, Technical Functions
J. Colitz, Plant Engineering Director, TMI-1
E. Hammond, Nuclear Safety Compliance Committee
R. Harding, TMI-1 Licensing
T. Hawkins, TMI-1 Startup and Test Manager, Technical Functions
H. Hukill, Director & Vice President, TMI-1
M. Knight, TMI-1 Licensing Engineer
R. McGoey, TMI-1 Licensing
R. Meyer, Nuclear Safety Compliance Committee
R. Neidig, TMI-1 Communications
J. Pearce, Senior Engineer I, TMI-1
M. Sanford, Mechanical Systems, Technical Functions
C. Smyth, TMI-1 Licensing Manager
R. Toole, Operation and Maintenance Director, TMI-1

NRC:

L. Bettenhausen, Chief, Operations Branch
A. Blough, Chief, Reactor Projects Section 1A
N. Blumberg, Lead Reactor Engineer
R. Conte, TMI-1 Restart Manager
W. Kane, Director, TMI-1 Restart Staff
J. Thoma, Project Manager, PWR Project Directorate #6, NRR
P. Wen, Reactor Engineer

State Representative:

W. Dornsife, Department of Environmental Resources, Commonwealth of Pa.
S. Maingi, Nuclear Engineer, Commonwealth of Pa.

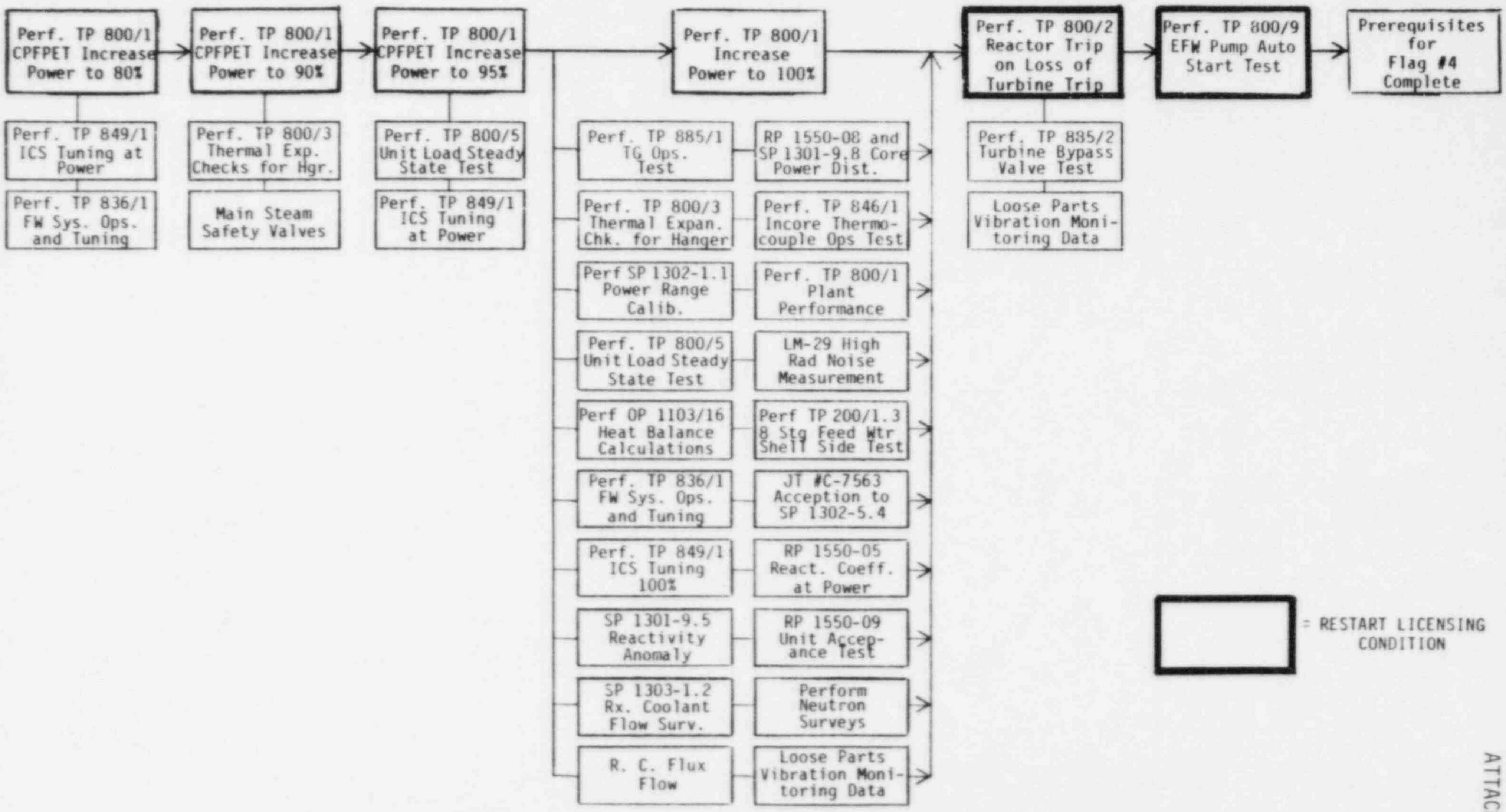
NRC MEETING ON TMI-1

STARTUP AND TEST PROGRAM

AGENDA - DECEMBER 17, 1985 AT TMI-1

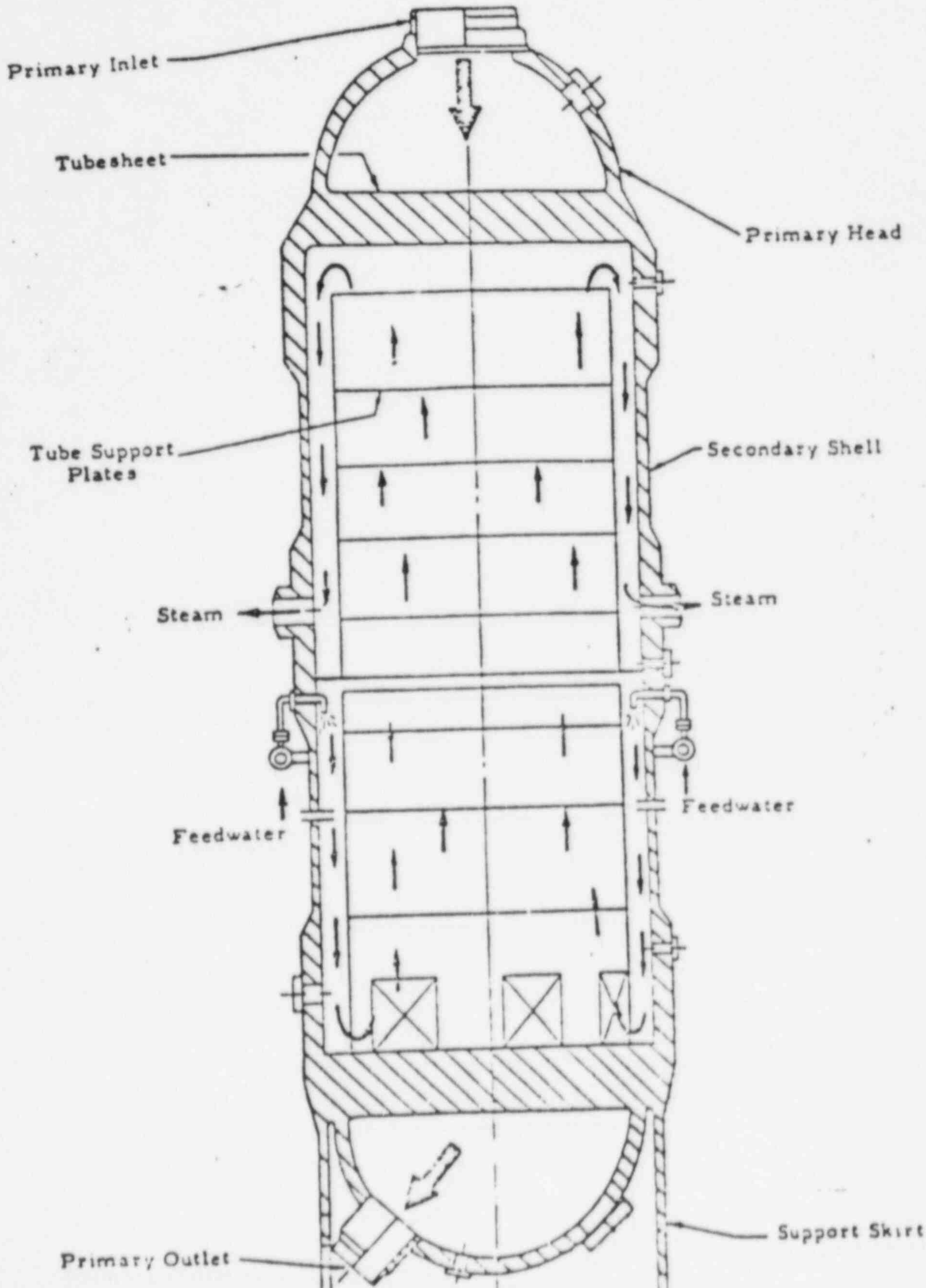
1.	Introduction	R. J. McGoey
2.	Overview and OTSG Crud Phenomenon	J. J. Colitz
3.	EFW Turbine Driven Pump Safeties Discussion	M. Sanford
4.	Main Steam Safety Discussion	M. Sanford
5.	Conclusion	R. J. McGoey

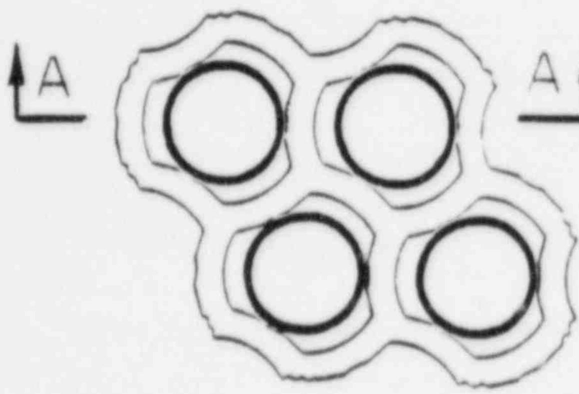
POWER ESCALATION TEST SEQUENCE

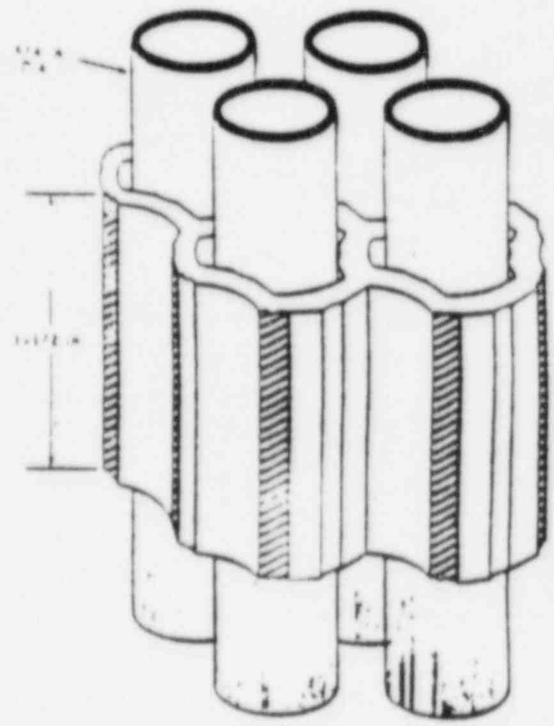


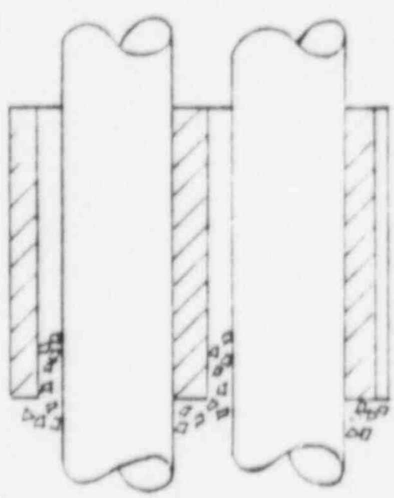
ATTACHMENT 1

Longitudinal Section of the OTSG



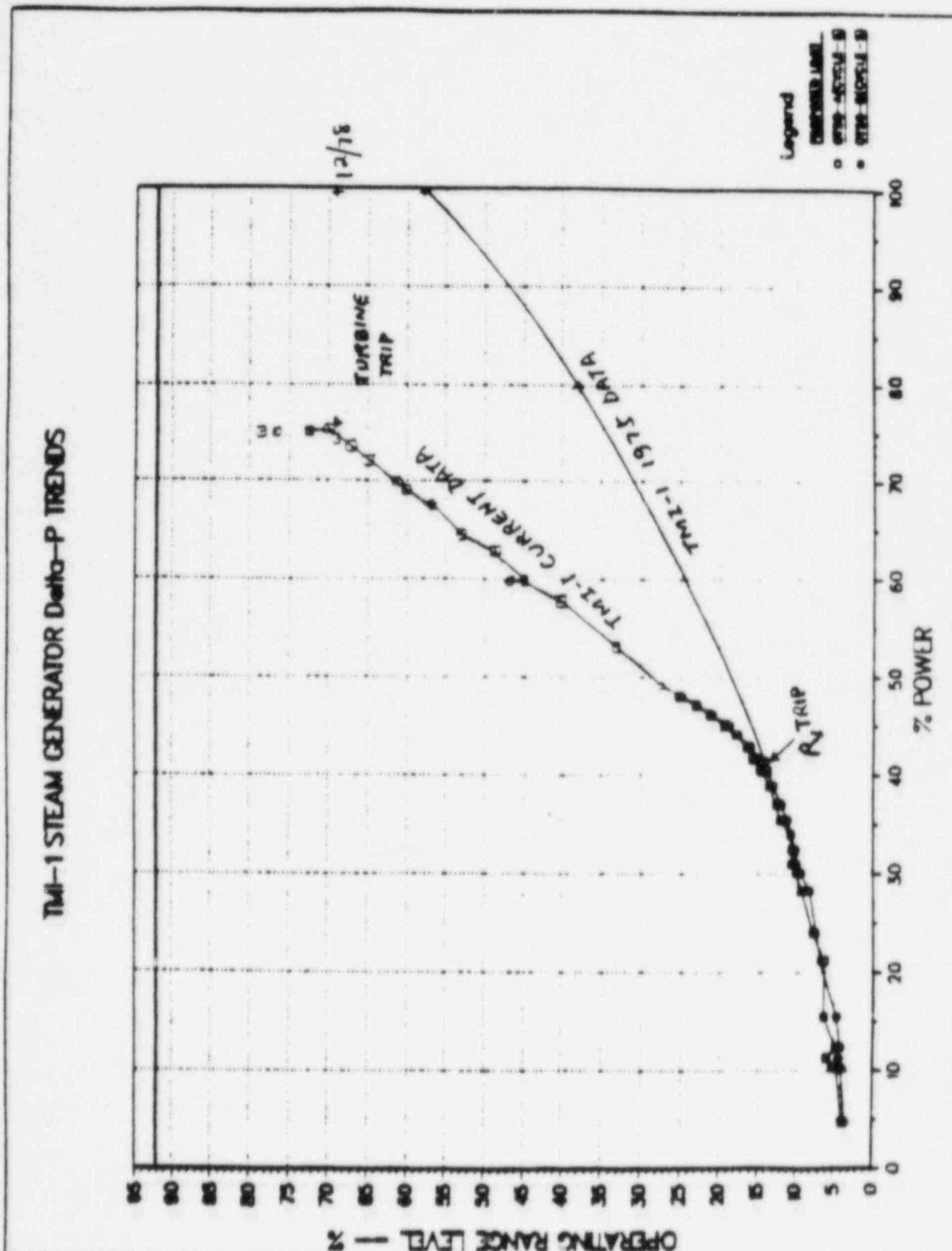






SECT A-A

ATTACHMENT 1



AGENDA

TMI- 1

EFW TURBINE DRIVEN PUMP MAIN STEAM SAFETY VALVES

I. CONCERN

MSV22B LIFTS UPON INITIATION OF EF-P-1

CONCERN: POTENTIAL STARVING OF EF-P-1 TURBINE.

II. EVALUATION

1. MSV22B LIFT ONLY OCCURS WITH SIMULTANEOUS MS-V13A/B OPENING.

2. PUMP WILL OPERATE WITH SAFETY VALVE OPEN.

3. PC-5/MSV-6 RESPONSE TOO SLOW TO PREVENT MSV22B LIFT.

III. INTERIM ACTION TAKEN

GUIDANCE PROVIDED TO OPERATOR IF SAFETY VALVE LIFTS DURING EF-P-1 OPERATION:

- o OPERATOR INSTRUCTED ON HOW TO RESEAT THE SAFETY VALVE
- o OPERATOR INSTRUCTED ON HOW TO TAKE EF-P-1 OUT OF SERVICE (IF SAFETY CAN'T BE RESEATED AND ADEQUATE MOTOR DRIVEN FLOW IS AVAILABLE)
- o OPERATOR INSTRUCTED ON HOW TO OPERATE EF-P-1 WITH SAFETY VALVE OPEN OR GAGGED CLOSED

IV. CURRENT ACTION PLAN

1. REVISE INTERIM (CORRECTIVE) ACTION:

   USE SINGLE VALVE OPEN LOGIC FOR SHORT TERM (CYCLE 5)

   - o JUMPER ACROSS MS-V13B AUTO START LOGIC TO KEEP MS-V13B CLOSED

   - o MANUALLY OPEN MS-V13B FROM CONTROL ROOM IF MS-V13A FAILS TO PROVIDE SUFFICIENT STEAM

2. IMPROVE RESPONSE TIME CHARACTERISTICS OF PRESSURE CONTROLER PC-5.

   - o INSTALL NEW PRESSURE CONTROLLER & VOLUME BOOSTER

   - o TEST FOR ACCEPTABLE PERFORMANCE WITH SIMULTANEOUS VALVE OPENING.

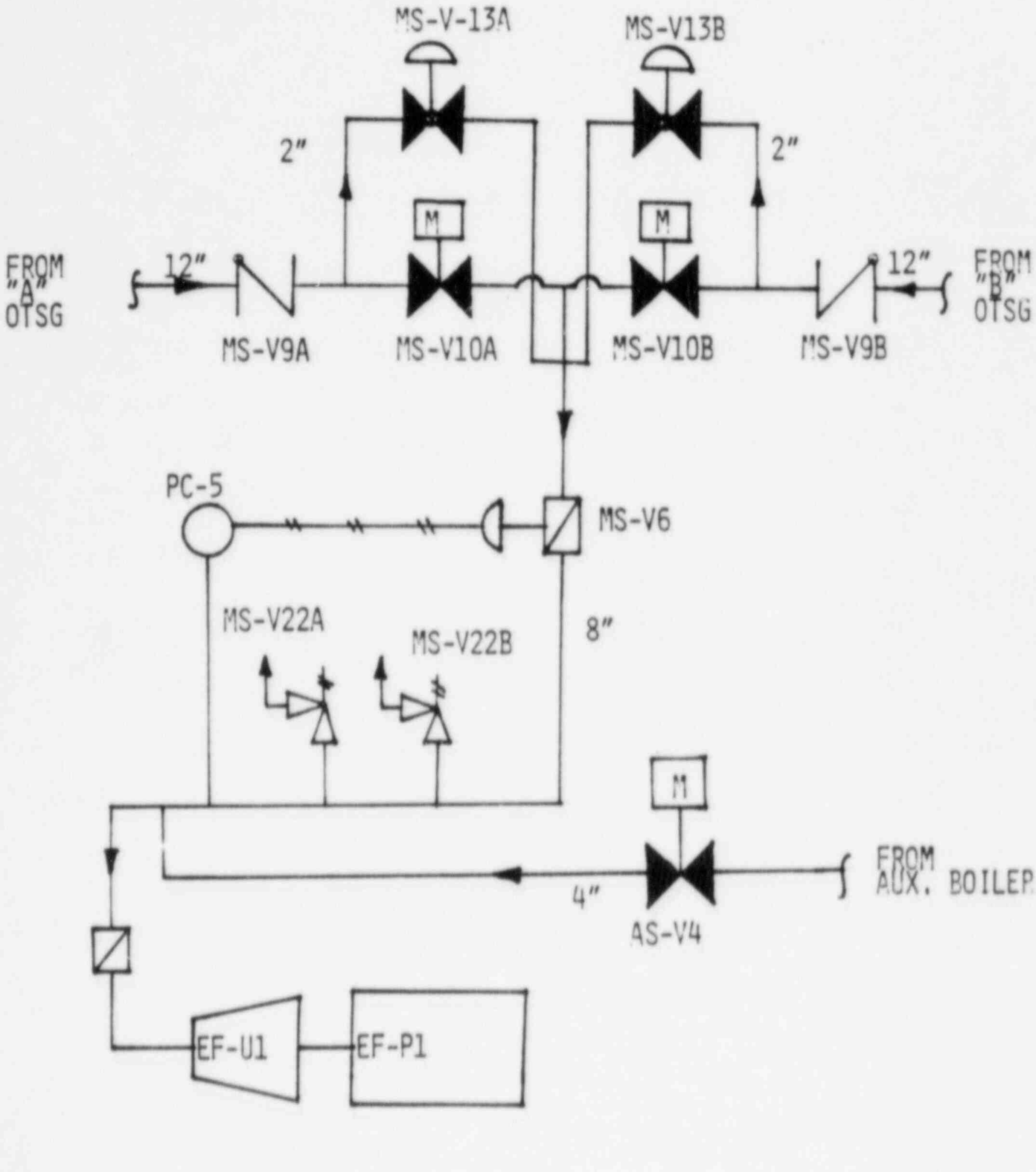
SUMMARY

1. MSV22B LIFT OCCURS ONLY WITH SIMULTANEOUS MSV13A/B OPENING.

2. o INTERIM ACTION TO BE REVISED TO ONLY OPEN ONE MSV13

   o IMPROVED CONTROLLER TO BE TESTED AS CORRECTIVE ACTION

3. ABOVE ASSURES EF-P-1 OPERABILITY ∴ NO NUCLEAR SAFETY CONCERN



TMI-1
STEAM SUPPLY TO
EFW PUMP TURBINE

MAIN STEAM SAFETY VALVES (MSSV'S)

EVENT

DATE: 10/21/85

- o 40% POWER TRIP
- o ALL MSSV'S LIFT
- o NUMBER OF MSSV'S RELIFT
- o PEAK RECORDED PRESSURE 1050 PSIG
- o RELIFTS AT APPROX. 1010 PSIG

EVALUATION

1. VALVE SETPOINTS WERE CONFIRMED CORRECT.

2. VALVE PERFORMANCE

   a) ALL VALVES INITIALLY LIFT FROM PRESSURE WAVE AS EXPECTED.

   b) BLOWDOWN IS WITHIN ACCEPTABLE BOUNDS (MSSV'S DID NOT EXCEED 10% BLOWDOWN)

   c) PROLONGED INITIAL LIFT COULD RESULT IN MSSV SETPOINT DRIFT (AS MUCH AS 3%)

   d) CONSISTENT WITH OBSERVATIONS AT OTHER PLANTS.

3. ANALYSIS SHOWS A SYSTEM PRESSURE SPIKE RELATED TO TURBINE STOP VALVE CLOSURE IN EXCESS OF HIGHEST MSSV SET POINT.

4. SAFETY VALVE PERFORMANCE MAINTAINED PLANT WITHIN DESIGN ENVELOPE DURING TRIP.

5. INADVERTANT 75% POWER TRIP SHOWED REPEATABILITY.

CONCLUSION

1. TMI-1 MSSV SETPOINTS ARE SET CORRECTLY.

2. TMI-1 MSSVS RESPONDED WITHIN EXPECTED TOLERANCES DURING THE PLANT TRIP.

3. TMI-1 CURRENT SETPOINTS ARE ADEQUATE FOR CONTINUED SAFE PLANT OPERATION AT ALL POWER LEVELS.

4. GPUN WILL CONTINUE TO INVESTIGATE MEANS TO IMPROVE THIS ALREADY ACCEPTABLE SITUATION.