U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-289/85-25

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 1

Inspection At: Middletown, Pennsylvania

Inspection Conducted: October 18-25, 1985

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TMI-1 Restart Staff
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Inspection Summary:
Routine and special (NRC shift coverage) safety inspection (352 hours) of power operations focusing on operator and management performance; startup testing which included 40% power plateau test review and witnessing; facility operations which included followup on rod exercise surveillance, calibration indicators, repair of leaks in reactor building, drawing control, and storage of combustible gases in safety-related areas; pressurizer power operated relief valve surveillance; Nuclear Safety and Compliance Committee staff activities; and administrative controls implementation in the areas of removal of equipment from service, instrument out of service control, caution tagging and post reactor trip review.

Inspection Results:
Operations department personnel continued to conduct activities in a professional manner and to use their skills to minimize challenges to safety related systems. Although some inexperience was apparent, non-licensed personnel also conducted themselves in a professional manner and properly implemented facility procedures in conjunction with licensed personnel. The inspectors noted a trend in which there was an apparent lapse of attention to detail in the documentation of certain events or abnormal conditions in various control room operations logs. In those cases other records reflected those observations for licensee corrective action which was completed or was initiated.

The testing program, to date, was effective in uncovering facility problems such as the unexpected interaction between the turbine bypass valves and the steam generator safety valves. Licensee representatives properly implemented the startup test procedures and they found that the data, with some exceptions, conformed to the test acceptance criteria.

Although inspectors later found the pressurizer power operated relief valve (PORV) had in fact been operable except during testing, the licensee's instrument and control (I&C) department poorly handled both the test and the retention of the test and deficiency documents for the PORV setpoint surveillance. Operations and I&C personnel inexperienced in performing the test contributed to the problem when shift personnel initially conducted the surveillance during the midshift.

Nuclear Safety and Compliance Committee (NSCC) staff activities meet or exceed regulatory requirements. However, NRC staff needs to complete its review of the NSCC activities performed by the committee.

Licensee management continued their detailed attentiveness and involvement and generally was responsive to NRC staff concerns. Management was particularly responsive to the PORV surveillance exception and deficiency sheets being thrown away and to inspector observations on personnel potentially violating a contamination boundary.

Administrative control procedures were technically adequate and, in general, were properly implemented. Also, the licensee needs to continue their assessment and corrective action related to the use of calibration stickers.

The inspectors identified an apparent violation of drawing control regulatory requirements for placards, sketches and drawings inside instrument cabinets in the control room (paragraph 3.2.5).

DETAILS

1. Introduction and Overview

1.1 General

At the beginning of this inspection period on October 18, 1985, the TMI-1 Restart Staff was providing around-the-clock coverage to assess restart operating activities. At 6:00 p.m., on October 24, 1985, this inspection coverage was reduced to 16 hours a day consistent with the reduced level of testing activity and steady-state facility operation at the 48% power plateau. This nearly continuous observation of plant activities was maintained by inspectors from Regions II and IV and by reactor operator examiners from Battelle Pacific Northwest Laboratories, an NRC contractor. Also, Region I inspectors continued daily coverage of testing 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 October 18-25, 1985, the significant TMI-1 restart operational milestones included: (1) completing main turbine generator testing and electric power generation at the 40% testing plateau, (2) completion of loss of main feedwater reactor/turbine trip, and (3) initial main turbine generator operation at the 48% plateau. The chronological summary of plant operations during the period is presented below.

Date	Time	Operational Highlight or Milestone
10/18/85	7:00 a.m.	Reactor at 7% of rated power pending completion of turbine control valve drain line repairs
	9:05 a.m.	Completed repairs to turbine control valve drain line and placed turbine generator on line
10/19/85	6:35 a.m.	Increased power to 41%
10/21/85	6:04 p.m.	Conducted loss of feedwater reactor trip/turbine trip
	6:50 p.m.	Commenced recovery from natural circulation
10/23/85	2:30 p.m.	Region I Administrator authorized the licensee to take the reactor critical and proceed with the test program at the 48% plateau
	4:12 p.m.	Commenced reactor startup

	5:57 p.m.	Reactor critical
	8:26 p.m.	Turbine generator on line
10/24/85	1:28 p.m.	Increased power to 48%
10/25/85	7:00 a.m.	At the end of this inspection period the reactor was at 48% of rated power, reactor coolant average temperature was 578 degrees F and pressure was 2150 psig

1.3 Operational Events

As described in Inspection Report 50-289/85-24, recurring problems with weld failures in two drain lines from the turbine control valve headers had delayed the restart testing program for several days. Repairs to the drain lines were completed on October 18, 1985, permitting continuation of the test program at the 40% power plateau.

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

Date	Operational Event
10/21/85	During post trip inspection of the reactor building, leaks were identified on an emergency feedwater flange and on a steam generator level instrument root valve (see paragraphs 3.2.4 and 4.2.2.4)
10/22/85	Group 1 safety rods would not respond to "in" command during pre-critical testing

The problem regarding movement of Group 1 safety rods was traced to the inability to transfer the rods from the dc hold bus to the auxiliary power supply. The dc hold bus does not provide motive power for rod movement. The licensee suspected a malfunction with transfer relays but the symptom was not repeated.

1.4 Summary

This inspection included continued progress of restart testing activities up to the 48% power plateau. During this period there was one interruption of the restart testing program while repairs were made to two leaks identified during post-trip inspection of the reactor building. The TMI-1 Restart Staff remained sensitive to an adverse impact on shift supervisor safety duties due to NRC shift inspector questioning and discussions of matters of a programmatic nature. Accordingly, the shift inspectors referred only implementation matters or status questions to the shift supervisor

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 operation 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 October 18-25, 1985, 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 testing activities, periodic surveillance activities, and preventive and corrective maintenance activities listed below.

Reactor Plant Operation and 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
- -- secondary plant auxiliary operator observation rounds and discussion of water treat system instruments, controls and interlocks
- -- shift preparations and conduct of turbine startup operations following drain line repairs
- -- power level increase to 25% of rated power
- -- power level increase to 40% of rated power
- -- startup of B condensate booster pump
- -- local startup of B heater drain pump
- -- advance management planning for reactor trip test
- -- changeover from B to A heater drain pump
- -- inspector operability verification of emergency diesel generators systems valve and breaker positions
- -- walkdown of secondary systems in company with an auxiliary operator
- -- instrument air compressor after cooler water trap blowdown
- -- shift turnover activities conducted by licensed operators and operating crew planning briefings conducted by shift foreman
- -- extensive operating crew and technical staff briefings in preparation for reactor trip test
- -- performance of loss of feedwater reactor/turbine trip at 40% of rated power
- -- fire drill at the emergency safeguards motor control center 1A

-- temporary change notice logbook, control room tagout and control room operator checklist implementation

-- turbine shell/chest heating activities prior to turbine generator operation

-- special temporary procedures administrative controls implementation

-- water addition to sodium hydroxide tank to increase tank pressure

-- crew performance of long form pre-critical checklist per procedure 1102-2

-- crew response to unexpected apparent reduction in shutdown margin

-- estimated critical position calculations for criticality

-- operating crew performance during reactor startup

-- operator actions during startup in response to group IV safety rods out interlock stopping group V control rod withdrawal

-- operator actions during startup in response to intermittent group I safety rods out interlock problem

-- turbine generator startup and load increase to 40% of rated power

-- turbine load increase to 48% of rated power

-- operator actions in response to continuing main feedwater system oscillations due to apparent control problem with main feedwater valve FW-V-17A

-- implementation of administrative controls for equipment operation including caution tags, out-of-service stickers, blue and red tags and switching logs

-- startup of B main feedwater pump

-- shift supervisor response to oxygen and hydrogen gas cylinders found stored in close proximity to each other by backup instrument air compressor in intermediate building

-- shift foreman response to untethered pressurized hydrogen bottle in Hayes gas analyzer room

Periodic Surveillance and Maintenance Testing

-- secondary service closed cooling water pump SC-P-1B testing in response to request from maintenance

-- accelerometer vibration measurements of main steam drain lines

-- local cycling of main feedwater regulating valves FW-V-17A&B for post-maintenance testing of controllers and valve position indication

-- portions of Surveillance Procedure 1303-7.2, "Source Range Channel," regarding count rate amplifier calibration and gain testing

-- procedure review of calibration tests for nuclear services closed cooling water line break isolation channels A and B

-- condenser vacuum pump exhaust sampling and analysis

-- reactor building fire detector testing

-- power range nuclear instrument adjustments

-- reactor coolant system heat balance measurements

-- spent fuel cooling pump functional test

-- power imbalance detector correlation test

-- reactor coolant pump seal leakoff "bucket check"

-- reactor protection system monthly surveillance testing per procedure 1303-4.1

-- high pressure injection and low pressure injection analog channels monthly surveillance testing per procedure 1303-4.19

-- radiation monitors system quarterly calibration testing per procedure 1302-3.1

-- control rod movement tests per procedure 1303-3.1

-- pressure switch calibrations for emergency feedwater start and reactor/turbine trip on loss of feedwater

-- emergency diesel generator monthly surveillance testing per procedure 1107-3

-- emergency safeguards systems monthly surveillance testing

-- pressurizer power-oriented relief valve setpoint check surveillance per procedure 1303-11.45

<u>Preventive and Corrective Maintenance Activities</u>

-- main steam drain line pipe threading in machine shop

-- packing leak adjustment to stop a leak in top of Amertap tank TC-11A

-- collar welding on equalizing line around condensate booster pump 1C suction valve CO-V-29C to stop a pinhole leak

-- partial review of program for instituting and controlling corrective maintenance activities

-- moisture separator drain tank sight glass level indication verification

-- seal installation in C heater drain pump

-- reactor building fire detector maintenance

-- reactor building purge outlet valve preventive maintenance (bushing inspection for wear and lubrication)

-- nuclear instrumentation channel 6 imbalance meter repairs

-- hydraulic oil addition to reactor coolant pumps

-- steam generator A emergency feedwater line flanged connection leakage repairs

-- feedwater root valve FW-V-1093 leakage repairs

-- investigation of reported empty or low hydraulic fluid reservoirs for snubbers in pressurizer safety valve relief lines

-- alcohol cleaning of contacts in reactor protection system cabinet 2 for nuclear instrumentation channel 4 log amplifier and startup rate drawers

-- troubleshooting of nuclear instrumentation channel 4 sporadic high peaking

-- repairs to inoperable controller for main feedwater pump B recirculation valve FW-V-7B

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 the licensee's shift supervisor and the 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. These general assessments included, as applicable, each inspector's overall views related to operating staff performance, fire protection, maintenance, surveillance, radiological controls, training, emergency planning, and physical security. The inspectors' assessments are presented below.

2.2.2 Operating Staff Performance

Shift inspectors continued to provide many positive comments on the knowledge level and overall quality of performance of facility operating, maintenance and technical staff personnel as described in detail in previous inspection reports 50-289/85-22 and 50-289/85-24. Those groups of individuals, that were closely monitored in addition to control room operators and shift supervisors were: shift technical advisers, instrumentation and control (I&C) technicians, and auxiliary operators.

The performance of certain individuals was noteworthy in that it reflected a professional attitude. An I&C technician took the initiative to clean the sediment out of a moisture separator sight glass drain plug during his troubleshooting efforts on a level control valve. A training instructor took the initiative on a Saturday to observe a heater drain pump seal installation. He explained that he taught that mechanical maintenance evolution and he wanted additional feedback on how to improve the lesson plan. Also, as a side note, one shift openly expressed disappointment that the post trip reactor startup was rescheduled for a different shift. Although these examples are attributed to only a few individuals in a relatively large organization, the general comments of the shift inspectors reflect that there is a general sense of dedication, motivation and caring displayed by the majority of the personnel observed.

In general, procedures continued to be properly implemented. Specific procedure implementation problems were noted in paragraphs 3.2.3 and 3.2.5. Further, an inspector observed an operator using a subcritical

multiplication "1/M" plot that was not a replica (in format) of the procedural required plot. This had no adverse effect on the proper method of performing the 1/M plot since the content of the form used was essentially the same as prescribed by procedures. The inspector brought this to the attention of licensee management and stated that the proper form should be used. Licensee management acknowledged the inspector's comments.

Overall, operators and technicians continued to perform in a professional manner.

2.2.3 Training

The reactor trip and subsequent startup during this period provided operators with excellent opportunities to gain operational experience, especially when the integrated control system (ICS) needed to be operated in manual. Shift supervisors and licensee management continued their emphasis on every event being a learning experience.

The licensee also conducted a fire drill during this period and it sufficiently demonstrated the fire fighting preparedness of the fire brigade. Based on observations of the shift fire drill and several on-shift training briefs, the inspectors determined that training was being conducted in a serious manner with appropriate participation.

Training appeared to provide plant personnel with sufficient skills and knowledge necessary to perform activities in a safe and proficient manner. Steady-state operations, as well as transient evolutions, were routinely utilized to provide an on-the-job training medium to increase training intensity and to accelerate shift operational experience. Observed on-the-job training was effectively conducted with experienced supervisors not just monitoring crew performance, but providing instruction before, during, and after evolutions. There was considerable sharing of information between operators, with no indication that there was an unwillingness on anyone's part to admit ignorance on a particular issue.

Individual checkouts to trainees in the licensing program were minimally adequate. Operators had little time to spend giving checkouts, and there seemed to be little uniformity as to the level of detail that went into a checkout. However, based on observations of personnel to date, it appears that the overall training pipeline is performance-oriented.

2.2.4 Fire Protection

Fire protection measures continued to be implemented adequately, based on shift inspector visual inspection, review of fire brigade assignments and training, monitoring of system surveillances conducted during the week, and fire extinguisher checks, none of which were past their inspection due date. At the beginning of the inspection period, the inspectors observed two instances where fire doors were left open or ajar primarily because of ventilation differential pressure imbalance and indirectly because certain personnel were not attentive to assure that the door was closed. The inspectors trended this observation throughout the inspection period and noted no additional instances of fire doors being left open or ajar.

2.2.5 Maintenance

Corrective maintenance was aggressively pursued and promptly effected. Maintenance personnel appeared to be well qualified and trained. However, a lack of experienced I&C supervision on the backshift became apparent when inexperienced technicians had problems calibrating the PORV reset setpoint during a backshift surveillance (see paragraph 5).

"Furmanite" repairs to the emergency feedwater header and to a valve inside the reactor building prior to restart following a planned trip demonstrated the licensee's high priority for maintaining the plant (see paragraph 3.2.4).

2.2.6 Surveillance

Surveillances required by the technical specifications were conducted at the specified frequency without exception. Technical specification required surveillances were provided for and controlled by a strong administrative program which ensured they were conducted at the specified frequency.

The calibration frequency of some instruments which were not related to technical specifications but provided parameter status of systems important-to-safety were not as stringently maintained as evidenced by the 38 months since the last calibration of the decay heat closed cooling surge tank level instruments. This frequency is at the discretion of the licensee.

An isolated problem was identified in the surveillance program concerning a technical specification required demonstration of control rod operability prior to criticality (see paragraph 3.2.2).

Operations supervision of surveillances was excellent, both from the standpoint of knowing what was being done and how it affected the plant. There were a number of times when the assigned control room operator was significantly pressed, and in each case he stopped distracting evolutions to concentrate on monitoring surveillances. An especially good job was done in preplanning of plant conditions to allow for the effective accomplishment of surveillances.

All surveillance procedures reviewed were adequate. One potential problem concerned uncontrolled labelling and schematic diagrams found in the back of the radiation monitor panels. It was not determined if they were ever used during surveillance testing (see paragraph 3.2.5).

2.2.7 Radiological Controls

Contaminated areas were posted and maps showing radiation and contamination levels were present at entry pads. Several components with potential leakage problems were encased within transparent yellow plastic to contain leakage. Tygon drain tubing crossing passage areas and drain openings was taped in place. Cleanliness and attention to minimize the spread of contamination were apparent.

For radiation work permit (RWP) entries, radiological control (radcon) technicians had considered ALARA requirements. Low dose rates were expected in the regions visited. Proper dosimetry including neutron monitoring and/or continuous technician coverage were provided in accordance with RWP requirements. Discussions with a radcon foreman on the intent and interpretation of the "continuous monitoring" requirements indicated a proper concern and emphasis upon area surveys and job planning to minimize personnel dose.

2.2.8 Physical Security

On one occasion the shift inspector discovered the card-entry door to the control room complex ajar. A security guard arrived within about two minutes to investigate and secure the door. Based on routine observations of security systems operation and guard performance no adverse conditions or problems were identified in this area.

2.3 Conclusion

Personnel performed in a professional manner. There were procedure implementation problems, but on a closer review it appeared they were due to individual inexperience or lack of familiarization and none adversely affected safe operation of the facility. Actual

plant experience continued to be a valuable training vehicle to support safe power operation. The operations department performed well during major challenges to their skills, e.g. the 40% reactor trip test and the subsequent natural circulation test during which natural circulation was lost.

Overall, maintenance and surveillance activities were properly conducted, although some examples of poor implementation practices were noted. Area radiological contamination control continues to be noteworthy. Radiological control procedures were properly implemented with health physics personnel demonstrating a genuine concern for worker radiation protection.

3. Plant Operations

3.1 Routine Review

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

-- 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 log-keeping practices

-- implementation of radiological controls

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

The inspectors 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 (paragraph 2)

-- areas outside the control room

-- selected licensee planning meetings

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

3.2 Findings

3.2.1 General

Licensee management continued their detailed involvement in all phases of plant operation. The operations manager directed major day-to-day plant activities while shift supervisors were held responsible for accomplishment of directives. Major plant evolutions were directly supervised by senior plant management with additional licensed personnel present to monitor plant parameters. After achieving the 48% power plateau, shift supervisors were allowed to fully direct routine shift activities and, thereby, demonstrate their management capabilities.

Licensed shift supervision maintained a high level of responsiveness to the concerns identified by the inspectors. These concerns included snubber fluid levels, water in the instrument air aftercooler water trap and leakage of a condensate tank recirculation line valve. The licensee's efforts in resolving and providing corrective actions concerning the PORV documentation and operability problems (see paragraph 5) further exemplified their regulatory responsiveness. As an additional example, licensee management was responsive to NRC concerns on how major test briefings were conducted. They conducted the briefing for the 40% trip test in the south auditorium which was more environmentally suitable. The briefing also included a discussion of response actions for operational problems that might be encountered.

The high motivation of licensee management apparently has filtered down to certain employees as described in paragraph 2.2.2 on the motivation of personnel observed performing work activities.

The radiological controls department was responsive in resolving an inspector's observation of an apparent violation of a contamination control barrier (NRC Inspection Report 50-289/85-24). Radcon department management interviewed those personnel involved and the licensee representatives determined that the workers were moving paint into the contaminated area. The inspector had no further comments on this matter.

In general, administrative procedures were properly implemented as described in paragraph 7. However, with respect to log keeping, details of certain events were not provided in the control room operator's log or shift

foreman's log. The leaks found in the reactor building (see paragraphs 3.2.4 and 4.2.2.4) were not logged but were recorded in another plant record, a work request, to initiate repair action.

The safety rod out limit interlock prevents movement of reactor control rod groups 5 to 7. The operational actions taken to correct the problem were not recorded. When this was brought to the plant operations manager's attention, he had a "late entry" placed in the shift foreman's log. Considering other log entries during this period and previous inspection periods, the inspector stated that the above log entry discrepancies were not characteristic of the past performance by the operator. The inspector also stated that this area will be trended during subsequent routine NRC reviews. The safety rods out interlock problem is unresolved pending further review (289/85-25-01).

3.2.2 Rod Exercise Surveillance

A shift inspector witnessed portions of surveillance procedure 1303-3.1, "Control Rod Drive Movement" (see paragraph 2.2.5). The procedure successfully demonstrated the operability of all safety rods as required by Technical Specification (TS) 4.7.1, but the shift inspector questioned how the surveillance would be current for startup when TS 4.7.1 requires the rod exercising only during power operations.

The resident inspector reviewed the surveillance data records and confirmed the shift inspector's findings. The TS 4.7.1 surveillance is performed to ensure that a stuck rod does not exist prior to returning to power operation or that a stuck rod does not go undetected for long periods of time while at power. There were no provisions in the licensee's startup procedure to perform this surveillance during or after an extended period at hot shutdown. The licensee was aware of the problem and was manually tracking this type of surveillance to assure its completion prior to startup. The inspector discussed the possibility that this should be part of the reactor startup checklist. Licensee representatives acknowledged this and stated it would be considered. The inspector concluded that the licensee was in compliance with TS 4.7.1 and had no further comments.

3.2.3 Calibration Stickers

During tours in the turbine and intermediate buildings, shift inspectors noted various instrument gages with calibration stickers that indicated the gages were past due for calibration. When challenged, the licensee

provided sufficient records, on a sampling basis, to demonstrate the calibration of gages within the specified intervals.

The resident inspector queried licensee representatives as to why the calibration stickers were not updated. Licensee representatives indicated that the calibration stickers were to be phased out and replaced with individual gage records that are now being used to assure proper calibration. The problem is that many calibration procedures still require the use of stickers and it is a low priority administrative effort to change these procedures. Based on this review and review of data related to testing in past inspection reports, the inspector concluded that operators used calibrated gages for regulatory required functional testing and control room parameter monitoring. However, the inspector stated that calibration stickers indicating past due calibration were confusing from an operator's viewpoint in that the reliability of the instrument could be questioned when data was needed for operations or testing. Licensee management acknowledged the problem and stated that the calibration sticker problem would be resolved on a higher priority basis. The inspector had no further comments in this area.

3.2.4 NRC Review of "Furmanite" Process

The restart staff reviewed the licensee's repairs to the leaking components found during the reactor building inspection (see paragraph 4.2.2.4). A sealant compound "Furmanite" was injected into the leaking area and formed a new gasket thus stopping the leaks. In the case of the flange leak, a machined sealing ring was bolted over the outer surfaces of the two flanges to form a void that was filled with Furmanite. This void formed a new pressure boundary and the injected Furmanite then sealed the boundary. In the case of the leaking valve the Furmanite was injected between the body and the bonnet and formed a new gasket.

The licensee's plant engineering group prepared a safety evaluation (10 CFR 50.59 review), No. 85-250-M, to determine the acceptability of Furmanite for this application. This review determined that there were "...No new unreviewed safety questions.... The flange injection clamp adds [approximately] 15 lbs. to the existing flange assembly...[which was] determined to be insignificant from a dead weight concern...[the added] mass does not degrade any previous seismic classification...."

While the work was in progress, the inspectors queried the licensee as to whether or not stresses on the flange bolts had been considered in the safety evaluation and the

inspector determined that it was not. The vendor's engineering group was contacted to perform such a calculation. Furmanite provided an analysis which indicated the bolts would not be overstressed. This was based on normal operating pressure of 900 psig leaking and being sealed by the Furmanite. The inspectors determined that, by applying higher pressures than the 900 psig, the bolts would not be overstressed.

The inspectors and licensee representatives discussed the effects of Furmanite injection during a telephone conversation with the vendor engineering representative. The vendor representative noted that although Furmanite was injected under pressure, this pressure tended to relieve itself. The vendor representative stated that the last segment of Furmanite installed might place some stress on the flange bolts but it should not be significant. The vendor representative also stated that, from their experience, stress analyses were not required for similar design rated flanges.

The inspectors reviewed the licensee safety evaluation. Based on this review, discussions with the licensee, discussions with Furmanite, and review of the Furmanite safety analysis for bolt stresses, the inspectors determined that the licensee's initial safety evaluation was acceptable. While the evaluation could have been more thorough and included an analysis of flange stresses, their not being included did not constitute a serious review deficiency. The inspector noted that safety evaluation (85-250-M) also included a review of the specific procedure for applying Furmanite to this flange. The licensee's generic procedure 1410-Y-44, "Use of Furmanite," was used in this process.

The staff concluded that the flange bolts would not be overstressed and the Furmanite process is an acceptable temporary repair method. The licensee committed to repair the joints prior to returning to power after the completion of the Spring 1986 eddy current outage. This matter is unresolved pending completion of licensee action as committed to above and subsequent NRC Region I review (289/85-25-02).

3.2.5 Drawing Control

During witnessing of a surveillance in a radiation monitoring system (RMS) cabinet located in control room console panel right front, the shift inspector observed circuit drawings and typed procedural notes posted on the inner cabinet door (see paragraph 2.2.6). Further inspection revealed that uncontrolled and unapproved drawings and procedural notes were posted to the inside of all eight RMS panel access doors and reactor protection system subassembly cabinet "C."

Administrative procedure (AP) 1001H, "Drawing Utilization," states that the use of drawings and notes are not authorized on plant panels. All drawings and procedures observed on the cabinet doors were removed by the instrument and controls supervisor.

The posting of uncontrolled and unapproved drawings and procedures on cabinet doors is contrary to 10 CFR 50, Appendix B, Criterion VI and licensee procedure AP 1001H and constitutes an apparent violation (289/85-25-03).

3.2.6 H_2/O_2 Storage

A shift inspector tour of the intermediate building revealed that hydrogen and oxygen gas cylinder bottles were stored side by side. The gases were used as calibration gases for the reactor building hydrogen monitors. The TMI-1 Restart Staff determined that, although the bottles were in seismically designed storage racks, this situation was not strictly in accordance with the licensee's occupational safety and health manual. Later review by licensee representatives in consultation with the Harrisburg OSHA (Occupational Safety and Health Administration) office determined that the storage aspects were acceptable. Plant engineering personnel also reviewed the situation and they concluded that no fire hazard existed. The adequacy of the licensee's hazard analysis for this area is unresolved pending a subsequent inspection (289/85-25-04).

3.3 Conclusion

Licensee management continued their detailed attentiveness and involvement in daily activities. In general, highly motivated managers appear to be instilling that same motivation in plant personnel.

There may be a need for more detailed recording of events or abnormal conditions in the control room logs when plant personnel make observations or conduct activities. A licensee decision is needed on whether or not to use and/or rely on calibration stickers on instruments in the plant. Apparently, this decision was being held up because numerous facility procedures are affected by that decision.

The licensee's post-trip review met the intent of the Salem ATWS (anticipated transient without scram) corrective actions. However, there could have been more plant engineering review and involvement on the stress analysis for the flange bolts during the planning phase for the "Furmanite Repairs." The licensee's 10 CFR 50.59 evaluation nevertheless was adequate to meet the requirements of that rule.

The drawing control problem was an apparent violation of regulatory requirements. However, it was not characteristic of the licensee's overall program since drawings and procedures available for use inside and outside the control room were verified to be controlled copies when checked during previous inspections since the program problem was identified in this area in 1981.

4. Startup and Power Escalation Testing

4.1 Scope of Review

4.1.1 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, "Trip on Loss of Feedwater," and TP 800/8, "RCS Overcooling 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 800/8 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 40% Power"

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

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

-- TP 800/2, "Trip on Loss of Feedwater"

-- TP 800/8, "RCS Overcooling Test"

-- OP 1105-14, "Loose Parts Vibration Monitoring Data"

-- RP 1550-01, "Incore Detector Checkout"

-- RP 1550-04, "Power Imbalance Detector Correlation"

4.1.2 Test Results Review

Test results from the testing program for the 40% power plateau 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 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.

4.2.1 Reactor Trip on Loss of Feedwater/Turbine Trip (TP 800/2)

4.2.1.1 Test Performance

Restart condition 2.b requires that prior to operation above 48% power, the licensee demonstrate automatic initiation of emergency feedwater (EFW) pumps upon loss of both main feedwater pumps. This test was performed on October 21, 1985, in accordance with TP 800/2, "Reactor Trip on Loss of Feedwater/Turbine Trip," during which both main feedwater pumps were tripped. Following the trip of

the feedwater pumps, the following events were expected to occur.

- -- reactor trip on anticipatory loss of feedwater
- -- turbine bypass setpoint transfers to 1010 psig
- -- turbine trip coincident with loss of main feedwater pumps
- -- containment isolation on reactor trip
- -- OTSG levels control at 30 inches using EFW flow
- -- all three EFW pumps start automatically

Operations and test personnel were stationed in the control room, at the remote shutdown panel, at the two motor driven and one steam driven EFW pumps, and outside the plant to visually monitor which main steam relief valves actually opened. Recorder charts were connected at the EFW pumps and remote shutdown panel for data recording.

Personnel were stationed at all three EFW pumps to assure proper operation of the pumps. To temporarily rectify a previous problem in which the steam supply relief valves to EFP-1 lifted during pump startup, one steam supply valve from the "A" OTSG (MS-V-13A) was shut and disabled from automatic actuation to reduce steam flow and preclude actuation of the relief valves. The previous actuation of these relief valves was detailed in inspection report 50-289/85-22.

The operator stationed at EF-P-1 was also tasked with opening of MS-V-13A manually, if necessary. MS-V-13B was allowed to operate automatically to supply steam to EF-P-1. In accordance with TP 800/2, after automatic actuation of EF-P-1 was demonstrated, EF-P-1 was secured from further operation so that motor driven pumps EF-P-2 A&B could control OTSG level.

4.2.1.2 Observations and Findings

Performance of plant operators and test engineers was observed in the control room and in the intermediate building at the emergency feedwater pumps. The following observations of operators and plant equipment were noted.

Control Room

Overall, operator performance appeared to be good. Operators were attentive, maintained their stations, monitored appropriate instrumentation, and reported

important readings and alarms. Plant operations for this test were directed by the plant operations manager. Test direction was formal, and operators were kept informed of overall plant status, test concerns, and impending actions. Procedures were followed completely.

Since a reactor trip took place, the immediate actions of ATP 1210-1, "Reactor Trip/Turbine Trip," were followed. A shift foreman read the procedure actions aloud and received formal responses from operators concerning completed actions. Communications during performance of post-trip actions were good. In general, annunciators were properly acknowledged.

Proper communications between the control room and plant stations, such as the EFW pumps and the outside safety valve watch, were maintained. The test was conducted according to procedure; test prerequisites were satisfied; and test limitations were observed.

Intermediate Building

The motor driven EFW pumps (EF-P-2 A&B) and the turbine driven EFW pump (EF-P-1) were manned by operations personnel who were in direct communications with the control room. Test engineering personnel were present to take data for the test, and plant engineering personnel were present to monitor inservice test parameters.

All three EFW pumps started on loss of main feedwater within the required time frame. As noted previously, one steam supply valve was shut to EF-P-1. This did not affect proper operation of EF-P-1, and the steam supply safety valves did not lift. The operator stationed at EF-P-1 was available to open the other steam supply valve if it had been required. However, as noted in inspection report 50-289/85-22, a satisfactory permanent resolution to the lifting of EF-P-1 safety valves on normal pump starts is required. As required by the test procedure, EF-P-1 was secured after approximately 12 minutes of operation. EF-P-2A and 2B continued to run to maintain OTSG levels and for the natural circulation test, TP 800/8.

Test Results

The test results indicated that actuation times for all three EFW pumps met the test acceptance criteria. For comparison, the results from the previous test as conducted per TP 700/2 as well as the results of TP 800/1 are included in the following table.

	Actuation Time (seconds)		Acceptance Criteria (seconds)
	TP 700/2	TP 800/2	
Turbine Driven Pump (EF-P-1)	15	20	<40
Motor Driven Pump (EF-P-2A)	3	1.8	<15
Motor Driven Pump (EF-P-2B)	3	2.0	<15

In addition to the automatic start of the EFW pumps after shutting off both main feedwater pumps the reactor tripped; the turbine tripped; partial containment isolation on reactor trip functioned; and OTSG levels were controlled at approximately 30 inches using EFW pumps. Another test objective, that the turbine bypass valve function at a turbine header pressure of 1010 ± 10 psig, did not appear to be proven by the test. Although the turbine bypass setpoint was found to be in calibration, the turbine bypass valves did not control turbine header steam pressure as expected. This problem is further detailed in paragraph 4.2.3 below.

4.2.2 RCS Overcooling Test (TP 800/8)

4.2.2.1 Test Performance

The licensee prepared test TP 800/8, "RCS Overcooling Test," to further demonstrate plant operation in a natural circulation mode and to gain additional real plant data concerning this operation. The basic objective of the test was to demonstrate that the control room operators could properly throttle EFW flow to prevent overcooling the reactor coolant system (RCS) while feeding the OTSGs following loss of the reactor coolant pumps (RCPs). The OTSGs were to be fed from an initial level of 30 inches in the startup range to a level of 50% (245 inches) in the operating range. During this transition, it was desired to start and maintain natural circulation.

TP 800/8 was not part of the restart test program committed to the NRC for the startup of TMI-1 and satisfactory completion of all aspects of this test were not required for satisfactory completion of the startup test program. TP 800/8 was scheduled following the trip during performance of TP 800/2 since the reactor would be shut down at this time. The driving force for natural circulation was to be an expected decay heat of 0.5 to 0.7% of rated power based on two to three days of operation at 40% of rated power.

Since this test was to take place immediately following the reactor trip, the operator and test engineer manning as stated for TP 800/2 was also in place for this test. The RCPs were stopped approximately 25 minutes after the reactor scram and after plant conditions had stabilized. The motor driven EFW pumps were already running and maintaining OTSG levels at approximately 30 inches.

Because of transients experienced on the restart of RCPs during performance of natural circulation test TP 700/2, an engineering evaluation had been done for TP 800/2. This resulted in a major revision to TP 800/2 which included setting a limit for reactor coolant system hot leg temperature (Th) prior to restart of the RCPs and manually controlling steam generator pressure just prior to and immediately after the starting of RCPs to minimize the secondary side pressure transient. An extensive two hour briefing was given to the operating crew which was to perform TP 800/2 and TP 800/8. This briefing included test performance, operator actions, possible problems, and expected plant responses in natural circulation and return to forced circulation. NRC inspectors attended and verified the acceptability of this briefing.

4.2.2.2 General Observations - RCS Overcooling Control Test

Since this test was done immediately following the reactor trip per TP 800/2, the observations concerning operator actions for TP 800/2 also apply to the performance of TP 800/8. As noted previously, the objective of the test was to raise the level in both OTSGs equally from 30 inches to 245 inches using EFW flow, raise OTSG levels without overcooling the RCS, and establish and maintain natural circulation.

Apparently, because there was insufficient decay heat, the licensee was not able to raise the OTSGs to the 50% level (operating range) and maintain natural circulation. However, a fundamental objective of the procedure was met in that the operators were able to throttle EFW to the OTSGs without overcooling of the RCS. It appears that

approximately 20 minutes after tripping of the RCPs, natural circulation was achieved for a short period of time in that a 30 degrees F temperature difference was obtained between Th and Tc; and Th and incore thermocouple temperatures were tracking. Th increased initially, reached a peak temperature of 556 degrees F at approximately 15 minutes then decreased in a continuous manner. The behavior of Th followed closely with the analytically predicted model (GPU study TDR-410, "RETRAN Analysis of the TMI-1 40% LOFW & Transition to Natural Circulation Startup Test") with the differences only in absolute peak Th value and the timing of reaching the peak.

Although Tc followed OTSG pressure, because of very low decay heat and possible excessive steaming in OTSG "A", the desired OTSG level of 50% operating range was not accomplished before OTSG "A" pressure dropped below 750 psig. The 750 psig OTSG pressure was one of the criteria to restart the RCPs per test procedure. The RCPs were subsequently restarted to establish the forced circulation.

The possibility of the depressurization in OTSG pressure below 750 psig during the test had been analyzed in the licensee's study (TDR-410). This was discussed in the briefing prior to the test. The inspector also noted that smooth natural circulation had been lost before forced circulation was established. Although, all test objectives were not completely met, licensee engineers stated they considered the test a success because sufficient information was obtained. The licensee is in the process of evaluating the test results. Appropriate information derived from this test will be issued for future plant operation guidelines.

4.2.2.3 <u>Licensee Post-Trip Data Review</u>

The resident inspector attended the licensee's post trip review of the trip test on October 21, 1985. The licensee review was required by Administrative Procedure 1063, "Reactor Trip Review Process." This was the first time that the licensee performed this review since the licensee significantly revised the procedure. As a result, it took the licensee several hours to perform this review with respect to gathering and properly reviewing the data. The licensee noted several minor administrative inconsistencies in the procedure that will be corrected. The post trip review identified the problem associated with turbine bypass control valves and main steam safety valves interaction which are described further in paragraphs 4.2.1.2 and 4.2.3 of this report. Subsequent to the post trip review, licensee representatives required that an independent safety review be conducted addressing, specifically, the safety valve-turbine bypass valve interaction problem.

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 was retrieved with no significant deficiencies noted. The inspector also reviewed the minutes of the independent safety review noted above. This review concluded that the manner in which the secondary system responded was not a safety concern and the plant could be safely returned to power. 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.

4.2.2.4 Post-Trip Reactor Building Inspection

Immediately following the loss of feedwater reactor/turbine trip on October 21, 1985, a shift inspector accompanied licensee representatives into the reactor building for a post-trip inspection. Two leaks were identified during the licensee's walkdown of the reactor building. The leaks were a flange leak on an emergency feedwater spray ring header on once through steam generator (OTSG) 1A and a valve body-to-bonnet leak on a steam generator level transmitter root valve, FW-V-1093. Both leaks were repaired by using a process known as "Furmaniting," as described in paragraph 3.2.4. The licensee's inspection of the reactor building was thorough and adverse conditions were properly identified to the operating shift.

4.2.2.5 Effect of 40% Reactor Trip on RCS and OTSG Leak Rates

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 day following the trip test (October 22, 1985) remained well within the technical specification's limits and were consistent with the previous day's result. No abnormal conditions were observed.

4.2.3 Turbine Bypass Valve Testing (TP 885/2)

TP 885/2, "Turbine Bypass Valve Testing," was performed in conjunction with TP 800/2, "Reactor Trip Test." The test objective was to verify that the six turbine bypass valves opened fully within three seconds after trip of the turbine, and that the turbine bypass valve functioned at 1010 psig ± 10 psig. During performance of TP 800/2, the main feedwater pumps tripped causing both a reactor trip and turbine trip. During the pressure increase in the steam headers, the turbine bypass control setpoint is expected to move to 1010 psig and attempt to control steam

pressure at this level. All the turbine bypass valves should fully open in less than three seconds. Since the bypass valves alone may not control the full header pressure transient, some of the main steam safety valves would then open to relieve further increases in header pressure.

Although the turbine bypass valves are not safety related, the results of this test warrant further review. During the test, the bypass valves failed to fully open. Since the valve indication limit switches are set at 5% and 95% the actual amount that the bypass valves opened was not known. However, post-test graphs indicated that integrated control system (ICS), turbine bypass "B" loop demand (valves MS-V-3A, 3B, and 3C) received an 80% open demand signal; and "A" loop demand (valves MS-V-3D, 3E, and 3F) received a 30% open demand signal. Hence, the bypass valve opening times could not be measured.

The failure of the turbine bypass valves to fully open was explained by the fact that the main steam safety relief valves opened before the turbine bypass valves. Based on visual observations of an operator stationed for this purpose, it appears that all eighteen main steam safety relief valves lifted. The lifting of the relief valves apparently took pressure control away from the turbine bypass valves.

Subsequent to the test, based on review of test graphs, calibration of steam pressure instruments, and the reaction of the ICS, the licensee initially concluded that some main steam relief valve set points may be set too low. The inspector reviewed test data for the setpoint test of six safety relief valves performed April 15, 1985, which were tested in place while the plant was at normal operating temperature. This data indicated that relief valves were properly set.

The licensee committed to: (1) document a test exception for the test results, with a test to be reaccomplished during the 100% trip test, (2) test the set points of the main steam safety valves and evaluate the need to set them at a higher pressure prior to going beyond the 75% power plateau (an NRC hold point), and (3) document this commitment in a letter to the Region I Administrator.

Also, TP 800/2 will be accomplished at 100% power, which tests the ability of the turbine bypass valves control setpoint to transfer and control pressure at 1010 psig following a reactor trip. This test problem is unresolved pending completion of licensee action as stated above and subsequent NRC review (289/85-25-05).

4.2.4 Unit Load Steady State Test (TP 800/5)

The steady state plant parameters as measured per TP 800/5 at 40% power plateau continuously showed good agreement with the predicted values. As noted in inspection report 50-289/85-24, at the 15% power level these values showed some deviation. Tave was expected to be 579 degrees F and actually was found to be 568 degrees F. However, Th and Tc measurements correlated well to expected values. Near the 15% power level the relationship of Tave to reactor power level makes the transition from an increasing linear relationship to a constant Tave relationship. Tave measurements at 25% and 40% power levels were as predicted.

The licensee again performed the test at 15% power during the startup after the 40% trip test. The test results were approximately the same as before. Discussions with B&W indicate that a Tave of 579 degrees F could be achieved if OTSG water levels were reduced from 30" to 25" or 26". However, the plant operators are reluctant to steam down to these low levels.

Test engineers are evaluating a test exception for this data point since the Tave data at higher power levels is as expected and the plant does not normally operate for lengthy periods at 15% power.

4.2.5 Loose Parts Monitoring (OP 1104.14)

The licensee continued to record loose parts monitoring base line data at each power level plateau. Sound levels were recorded at 40% power both before and after the reactor trip at 40%. A B&W technician was on hand to record data and to personally monitor audio channels. No loose parts or significant unusual noises were detected.

4.2.6 Core Power Distribution Verification (RP 1550-08)

The detailed core power distribution at the 40% power plateau was measured by the licensee per procedure RF 1550-08, "Core Power Distribution Verification," using the incore detector system. The incore detector system contains fifty-two incore flux detector assemblies with seven detectors per assembly. The inspector noted the following results:

-- The readings from symmetrical location detectors were within 10% of the symmetrical group average values.

-- The measured radial peaking factor for each fuel assembly was consistent with the analytically predicted value. The comparison of the highest measured radial peaking factor (1.291) at core

location K-11 agreed closely with the predicted value of 1.298.

-- The measured total peaking factor in each fuel assembly also agreed consistently well with the predicted value. The highest measured total peaking factor of 1.585 agreed well with the predicted value of 1.462 and was within the established acceptance range of 12%.

-- 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	2.490	15.20
9.43	4.496	16.26
7.71	4.942	17.10
6.00	4.756	17.50
4.29	4.422	16.31
2.57	4.311	14.37
0.86	3.159	11.48

All results were acceptable.

4.2.7 Power Imbalance Detector Correlation Test (RP 1550-04)

Power imbalances from power range channels (NI-5 through 8) were fed to the reactor protection system to provide the power-flow-imbalance trip. The licensee performed an out-of-core imbalance calibration using information from the incore detector system per test procedure RF 1550-04, "Power Imbalance Detector Correlation Test," Revision 9. Through test data review, the inspector noted that an excellent linear relationship exists between the indicated out-of-core power distribution and the actual measured incore values. The slopes of measured out-of-core imbalance to incore imbalance were 1.22, 1.23, 1.12, and 1.15 for NI-5, NI-6, NI-7, and NI-8, respectively. The acceptance criterion for this correlation slope was greater than 1.15. Upon completion of this test, the reactor protection system channel C difference amplifier gain from NI-7 input was adjusted by instrument and controls technicians in accordance with procedure SP 1303-4.1 Appendix B, "Procedure for Changing Scaled Difference Amplifier (Delta Flux) Gain," on October 21, 1985. The inspector verified that the actual "difference amplifier" gain setting K value of 5.035 (corresponding to an imbalance slope of 1.15 as described above) was properly implemented in the calibration. The inspector

also noted that during this test the quadrant power tilt values which ranged from 2.01 to 2.71 were all within the TS 3.5.2.4 limit of 3.52.

4.2.8 Restart Condition Verification

Restart condition 2.b stated the following:

> "Prior to operation above 48% power, GPU Nuclear Corporation shall demonstrate automatic initiation of EFW pumps upon loss of both feedwater pumps."

As discussed in paragraph 4.2.1, this was demonstrated by performance of TP 800/2. The inspectors verified satisfactory performance of TP 800/2 and that the required restart condition was met.

4.3 Conclusion

Testing for the 40% power plateau was accomplished in accordance with procedures, data were acceptable, and test objectives were met or proper test exceptions taken. Licensee management was responsive to inspector observations. Problem areas were quickly corrected and actions were taken to preclude their recurrence. Overall, licensee performance in the test area can be considered acceptable and, to date, test results are acceptable to proceed with the startup program. The adequacy of the OTSG safety valve settings needs to be resolved.

5. Pressurizer Power Operated Relief Valve (PORV) Setpoint Check

5.1 Discussion

On October 25, 1985, the NRC shift inspector witnessed portions of surveillance procedure 1303-11.45, "PORV Setpoint Check," Revision 5, September 3, 1985, from the control room. Two instrument and control (I&C) technicians performed this test at the module cabinet located in the relay room one floor below the control room. The first portion of the test required that the fuses be pulled on the electrical control power to the PORV making it inoperable. This action invoked Technical Specification 3.1.12.3 requirements that the associated block valve be closed within one hour of the PORV being declared inoperable. This one hour time clock requirement was logged in the shift foreman's log at 1:45 a.m.

As one of the technicians was increasing the test voltage setting on the equipment used in conjunction with this surveillance the control room operator and the NRC shift inspector noted an unexpected low spike on pressurizer level channel 1 in the control room. The low spike was sufficiently large to cause the low pressurizer level annunciator to actuate. The shift supervisor and the technicians reviewed the wiring logic diagrams and determined that the prescribed test sequence should not affect pressurizer level

instrumentation. The I&C technicians performed the steps again and were able to repeat the spike on the pressurizer level channel 1 instrument. The shift supervisor then directed that pressurizer level channel 3 be selected. The technicians performed the steps again and this time they had no effect on the pressurizer level channel that was selected. The shift supervisor then gave permission to continue with the surveillance test. The effect of the PORV calibration check on pressurizer level was not completely resolved at that time, only to the point of licensee supposition that a loose wire existed in the same cabinet that was being worked on.

The I&C technicians successfully performed the surveillance procedure up to the point of checking the trip (opening pressure) setpoint, which was found to be within technical specification tolerance (2450 ± 25 psig). Before starting the portion of the procedure associated with checking the reset (closing pressure) setpoint, the technicians determined that the procedure could not be performed as written and generated an exception sheet. The technicians discussed the exception sheet with the shift supervisor who concurred with the noted exception. He gave them permission to perform the steps in the corrected sequence as described on the exception sheet. Later, senior day shift I&C technicians determined that the two technicians had misread the procedure.

The two technicians then obtained reset setpoint voltage readings. The value (2438 psig) obtained was out of tolerance high (2400 ± 6.25 psig). This value would allow the PORV to be able to reseat after lifting at a high pressure, but the setting would cause the PORV blowdown time to be shorter. The technicians generated a deficiency sheet addressing the noted out-of-tolerance value for the PORV reset pressure. The technicians brought the deficiency to the shift supervisor's attention, and after discussing the findings, permission was given to recalibrate the setpoint.

In the meantime the shift supervisor, because of the technical specification one-hour time clock requirement, directed the block valve (RC-V-2) to be shut. This was logged in the shift foreman's log as occurring at 2:37 a.m.

The I&C technicians, however, were unable to recalibrate the reset setpoint, and they discussed this problem with the shift supervisor. The shift supervisor directed them to return all calibrated adjustment device values back to where they had found them prior to starting the surveillance. He also directed them to disconnect all test equipment and close the cabinets. The surveillance was terminated and would be turned over to the day shift and more experienced I&C technicians. At 2:52 a.m., as recorded in the shift foreman's log, the PORV fuses were installed and the block valve was opened. The shift supervisor declared the PORV to be operable at that time.

At approximately 7:30 a.m., the NRC inspectors requested to see the documents associated with the surveillance. The NRC inspectors were

directed to the senior day shift I&C technician who was following up on this matter. At that time, the original surveillance procedure could not be found, but the original exception and deficiency sheets were found in a trash can in the I&C shop by the I&C technician and the NRC inspectors.

Based on preliminary assessment of the information known of this matter, the inspector questioned the operability of the PORV. The inspector discussed his concern with the plant operations manager who stated that he considered the PORV operable; however, he directed a bench test of the module in question to be performed immediately to resolve the inspector's concern. The bench test determined that both the trip and reset setpoint values were within the allowable tolerances. The inspector acknowledged that the PORV was operable and had no further questions about the operability of the valve.

While performing the bench test, the licensee contacted one of the two technicians to determine the location of the original surveillance procedure. At 10:30 a.m. the licensee was able to locate the original surveillance procedure and reported that it was on a desk in the I&C shop. In addition, later that day, SP 1303-11.45 was properly performed and reconfirmed that the PORV setpoints were correct.

The dayshift I&C technicians reported that the surveillance was performed in error during the midshift because the technicians did not correctly perform step 8.1.8.1 of the procedure which clarified where voltages were to be read for a proper calibration check.

5.2 Scope of Review

The inspectors reviewed the incident on the apparent improper performance of the PORV surveillance and the licensee's review of this matter to determine the following items.

-- details regarding the cause of the incident and the chronology

-- consistency of licensee actions with license requirements, approved procedures, and the nature of the incident

-- proposed licensee actions to correct the cause of the incident

The inspectors' review of the surveillance activity included discussions with cognizant licensee personnel and review of the following documents.

-- Surveillance procedure (SP) 1303-11.45, Revision 5, September 3, 1985, "PORV Setpoint Check"

-- SP 1303-11.45, partially completed procedure from the midshift on October 25, 1985

- -- Exception Sheet E-1 to SP 1303-11.45, dated October 25, 1985
- -- Deficiency Sheet D-2 to SP 1303-11.45, dated October 25, 1985
- -- (Draft) Plant Incident Report No. 1-85-13
- -- Shift foreman log and control room operator log for October 25, 1985

The inspectors also accompanied licensee personnel while they performed the bench test of the PORV reset value.

5.3 Licensee's Review/Findings

During the morning of October 25, 1985, the TMI-1 Restart Staff expressed concern regarding the apparent poor document control practice of the exception and deficiency forms being thrown away and the relatively poor performance on the completion of an apparently routine calibration check. The licensee immediately dedicated two senior knowledgeable individuals to independently review the event and resolve the staff's concerns. Their review included interviews with personnel involved and a review of the applicable logs. A reconstruction of the event chronology was generated as part of the review. In addition, the licensee convened the Plant Review Group to review the data to determine if the licensee was proceeding in a correct manner with respect to the operability question of the PORV. Although plant management had already concluded that the PORV was operable, as an independent verification the licensee stopped scheduled maintenance testing and performed a bench test of the PORV module in order to be responsive to the NRC concerns. The bench test was quickly able to determine the operability of the PORV. In addition, the licensee conducted an immediate search to locate the missing surveillance procedure.

Subsequently, the licensee decided to develop a plant incident report (PIR) as the mechanism to capture the information and to disseminate lessons learned. Based on their review, as stated in the PIR, the licensee concluded the actions of the shift supervisor were correct and in accordance with the technical specifications. The shift supervisor properly directed and controlled the events in accordance with applicable facility procedures. All independent reviews performed, including the Plant Review Group review and reviews by different plant managers as part of their normal responsibilities, did not uncover any significant safety concern. The PORV was considered operable by the licensee at all times during this event, except during actual surveillance testing.

With respect to discarding the exception and deficiency sheets, the licensee's review was unable to determine how this occurred or who discarded them. The licensee, however, concluded that there was

in place, as part of their administrative controls program, various checks and balances that would have identified that the sheets were missing. The surveillance procedure coordinator is specifically tasked with reviewing all surveillance packages for completeness. In addition, the noted deficiency and exception were described on the shift turnover sheet which would trigger identification of the problem to I&C personnel from the operations department.

Also, the licensee concluded that surveillance packages should remain together at all times.

The licensee found that the shift supervisor could have asked more probing questions associated with the noted exception sheet generated by the two technicians. It was determined that the two technicians had never performed this test before and had misread the procedure. If the shift supervisor had asked more questions, misreading of the procedure may have been identified. The procedure as written was correct and properly obtained the required data. The data obtained by the technicians for the PORV reset pressure setting was not actually the required reading due to improper test connections being used. These test connections were not the required test connections specified in the written surveillance procedure. The surveillance that was performed on the dayshift verified that the procedure could be performed as written and that the PORV was operable.

The licensee plans to review the event with all personnel who may be involved with official facility surveillance records. The requirement to maintain and preserve legal records will be restated.

5.4 NRC Staff Findings

The licensee was responsive to NRC concerns and their actions were timely and provided sufficient information to permit the concerns associated with PORV operability to be resolved immediately. Although the shift supervisor could have been more inquisitive, especially on the rather routine surveillance, the shift supervisor's action on the operability of the PORV was technically correct and he complied with technical specifications. The shift supervisor could have better substantiated by documentation his reasoning on the operability of the PORV. Also, the inspector reviewed and concurred with the findings in the licensee's plant incident report.

With respect to the documentation control problem, licensee personnel did not maintain control of the surveillance package in that the exception and deficiency forms were separated from the surveillance procedure, contrary to AP 1001J provisions, and personnel were careless by either discarding the forms or not providing enough attention to detail to assure the completed package was retained.

It is merely speculative as to whether or not Technical Specification 6.10 requirements to maintain original plant records would have been adhered to since that issue was dependent on whether or not the licensee's review process would have identified the missing records (E&D forms). Since the surveillance procedure had not been discarded, it is likely that the exception and deficiency sheets would have been identified as missing. However, this may not have occurred in time for the records to be retrieved from the trash. The licensee then would have had to reproduce a reconstructed record which would be a violation of TS 6.10.

From our independent review of this matter, the inspector concluded there was no apparent motive to cover up the event. The E&D forms were in an obvious place -- the trash can in the I&C shop, which was not a place one would discard a record if one were trying to cover up the event. Further, three other records of the event were retained, i.e., the completed procedure and the control room narrative logs. Further the apparently adverse test results did not reflect an immediate need to shut down the facility.

A review of the exception and deficiency sheets (required by AP 1001J) indicated that the questions on the form were not clear as to the intent of each question. In response to one of the questions on the deficiency D-2, the shift supervisor marked "yes" indicating that the deficiency (lack of proper reset value for the PORV) reflected a failure to meet TS acceptance criteria. However, the shift foreman's log reflected that the shift supervisor determined that the PORV was operable without details of how he came to that conclusion. (It is well recognized that a specific TS LCO alone does not determine operability because the specific TS must be reviewed in conjunction with the TS definition of operability, TS 1.3.) Licensee managers reported that shift supervisors were instructed to mark yes to the above noted question when the more restrictive criteria of the applicable surveillance procedure could not be met. The inspector noted that no provisions then exist on the E&D form to determine operability of the surveillance component and that it would appear that the shift supervisor did not adequately resolve the deficiency before declaring the component operable.

The problem was evident upon review of the computerized outstanding E&D list in which a number of deficiencies were listed; but, upon closer review, one found procedural, editorial, or updating problems; not TS compliance or operability problems. The licensee acknowledged this situation and agreed to review this area along with submitting a report on this matter to NRC Region I. This is unresolved pending completion of licensee action to assure that surveillance test exceptions/deficiencies are appropriately reviewed for operability, TS compliance, reportability, and pending the submittal of a report to the NRC on the incident. Further licensee corrective action for this incident will be reviewed in a future inspection (289/85-25-06).

5.5 Conclusions

The licensee's initial and followup actions were responsive to the NRC concerns. The PORV was always operable. Licensee operators maintained the plant in the mode which they considered to be safest. No motive for wrongdoing in discarding the deficiency and exception sheet was noted. Existing documentation and handling measures for surveillance test exceptions and deficiencies were considered to be poor and warrant improvement.

6. Nuclear Safety and Compliance Committee Performance

6.1 Review

By Commission Memorandum and Order CLI-85-2, dated February 25, 1985, the licensee was required to maintain an expanded Board of Directors and a Nuclear Safety and Compliance Committee (NSCC). The committee is to have a staff of its own and is designated to monitor the operation and maintenance of the GPU systems nuclear units with specific attention to adherence to procedures and license requirements. This requirement was restated as restart condition 1.t by NRC letter dated October 2, 1985.

The NSCC of the GPU Board of Directors was established on February 23, 1984. The committee consists of three outside members of the GPU Nuclear Board of Directors. This committee has established on the TMI-1 site a staff consisting of a staff director and three members. This staff has been established to assist the NSCC in accomplishing its mandate. The staff activities are governed by NSCC staff guidelines.

During this inspection, the activities of the TMI-1 NSCC site staff were reviewed. The on-site staff performs evaluations in accordance with a six-month activity schedule which has been approved by the NSCC. The current activity schedule (July to December 1985) provides for monitoring in the following areas.

Operations

-- monitor conduct of operations by ongoing in-plant observations

-- evaluate normal and emergency operating procedures

-- monitor control room audit groups

-- operations surveillance

-- radioactive waste operations

Maintenance

-- control of heavy loads

-- system maintenance and testing, including:

- -- containment
- -- reactor pressure boundary
- -- maintenance of EQ components
- -- restart activities
- -- Davis-Besse lessons learned
- -- control of maintenance

-- corrective maintenance reports to NRC

-- planning and scheduling (evaluate outage preparations)

-- response to NRC and INPO findings

Training

-- maintenance training

-- STA training

-- simulator instructors

-- INPO accreditation

Licensing

-- evaluate LER/PRE (Licensee Event Report/Potentially Reportable Event Reports)

-- action item tracking

-- preliminary safety concerns

Radiological Control

-- contamination control

-- radiation awareness reports

Chemistry

-- monitor chemistry department operations

-- chemistry procedures

Technical Functions

-- operating experience and assessment overview

Safety Committees

-- GORB

-- plant review group

-- IOSRG

-- other

Quality Assurance

-- evaluate corrective action systems (QDRs, MNCRs, Audits, LER followup, etc.)

Emergency Preparedness

-- monitor exercises and drills

Plant Engineering

-- overview of organization and responsibilities

NSCC Requests

-- observations meeting

-- Davis-Besse incident

-- biennial procedure review followup

-- plant incident reports

-- procedure standardization

-- MORT training

-- NSCC semi-annual report

The following evaluation reports of evaluations conducted as described in the activity schedule have been issued since January 1, 1985.

-- TMI-R-85.001, Instructor Training and Qualification, April 2, 1985

-- TMI-R-85.002, Evaluation of Control Room Audits, March 15, 1985

-- TMI-R-85.003, Procurement and Control of Parts, Materials, and Services, March 15, 1985

-- TMI-R-85.004, Processing of Design Change Packages, March 25, 1985

-- TMI-R-85.005, Control of Special Processes, March 29, 1985

-- TMI-R-85.006, Investigation into the Use of Inappropriate Welding Procedures

-- TMI-R-85.007, Instrument Calibration Stickers, May 21, 1985

-- TMI-R-85.008, Training Document Control, Records and Records Retention, April 17, 1985

-- TMI-R-85.009, Training Examination Control Process, April 30, 1985

-- TMI-R-85.010, Normal and Emergency Operating Procedures, May 6, 1985

-- TMI-R-85.011, Control of Measuring and Test Equipment, May 21, 1985

-- TMI-R-85.012, Evaluation of the Control of Equipment Status, May 23, 1985

-- TMI-R-85.013, Evaluation of Emergency Preparedness, June 20, 1985

-- TMI-R-85.014, Review of Independent Onsite Safety Review Group (IOSRG), July 29, 1985

-- TMI-R-85.015, Review of Potential Safety Concerns and Potential Reportable Events, September 5, 1985

-- TMI-R-85.016, Evaluation of Training Program Development Approval and Review

The inspector also reviewed the following NSCC documentation.

-- monthly reports of NSCC staff activities for the months of July and September 1985

-- minutes of NSCC-NSCC staff meeting conducted July 23, 1985

-- Nuclear Safety and Compliance Committee report No. 1 to the GPU Nuclear Board of Directors, October 15, 1984

-- Nuclear Safety and Compliance Committee Report No. 2 to the GPU Nuclear Board of Directors, April 15, 1985

-- draft Nuclear Safety and Compliance Committee staff semi-annual report for the period April 1, 1985, through September 30, 1985

A number of questions developed during the review of the above documents. These were discussed with NSCC staff members as follows.

-- The activity schedule provides for a significant amount of time to be spent evaluating operations and maintenance, yet no evaluation reports are issued which discuss these areas.

The staff stated this time is devoted to the routine observations of operations and maintenance. If matters which require further staff evaluation were identified, results of these evaluations would be documented in evaluation reports.

-- The monthly reports discuss matters in which the staff is involved which are not documented in evaluation reports.

These are activities in which the staff has been involved during routine observations but not to the extent that an evaluation report is appropriate. The monthly report does provide the committee with some information on these topics. If the committee feels more information is necessary, they would request it from the staff.

-- It appears not all findings and recommendations which appear in evaluation reports are included in the NSCC's semi-annual report to the board. How are these transmitted to the site or sites?

One method by which these are transmitted is during scheduled observation meetings with the committee, the committee staff and senior GPU management. There may be other methods of which the staff is not aware.

-- Is there routine followup to implementation of findings and recommendations?

There is no formally established planned followup to findings and recommendations known to the NSCC staff.

-- Monthly reports discuss trending of certain data. What is being trended by the staff?

The following is being trended:

- unit availability
- heat rate
- audit findings (QA)
- radiological data
- injury rates
- iodine ratio

-- open job tickets

-- Are activities at Parsippany also evaluated?

Activities at Parsippany are also evaluated by the staff.

-- How frequently are NSCC and NSCC staff meetings held?

These meetings are held monthly and generally last over six hours each. These meetings provide for a major exchange of information between the committee and the staff.

6.2 NRC Findings

The requirement that an NSCC with an independent staff be maintained to monitor the operation and maintenance of TMI-1, with specific attention to adherence to procedures and licensee requirements is being met. Staff guidelines have been prepared which describe the staff activities which are to be performed in order for the committee to perform its task. These guidelines are being adhered to. A staff, which has approximately 80 man-years of nuclear experience in various disciplines, has been established at the TMI-1 site to perform evaluations. Based on discussions with staff members the committee appears to stay well informed of site activities and staff findings both through the receipt of staff reports (semi-annual report to NSCC, monthly report to NSCC, and specific evaluation reports) and through monthly meetings with the staff.

Staff evaluation reports and semi-annual reports to the committee are detailed and reflect adherence to a preplanned schedule. The committee, in addition to approving a staff activity schedule, frequently makes specific requests for evaluations or other actions from the staff. There does not appear to be any formal followup by the staff as to the disposition of evaluation findings and recommendations.

The committee's evaluation and disposition of staff findings and recommendations other than those formally transmitted by reports to the GPU Nuclear Board of Directors is beyond the scope of this site inspection. This area is unresolved pending NRC Region I additional review of NSCC activities (289/85-25-07).

6.3 Conclusion

The licensee is meeting the requirements of restart condition 1.t to retain the NSCC. Additional NRC staff review will be needed to evaluate the effectiveness of the NSCC.

7. Administrative Control Implementation

7.1 Review

The inspectors reviewed selected TMI-1 Administrative Control Procedures to verify that APs were properly implemented by licensee personnel.

The selected procedures reviewed included:

-- AP 1002, Revision 36, October 14, 1985, "Rules for the Protection of Employees Working on Electrical and Mechanical Apparatus";

-- AP 1036, Revision 6, February 10, 1985, "Instrument Out-of-Service Control";

-- AP 1037, Revision 4, January 3, 1985, "Control of Caution and DNO Tags"; and,

-- AP 1063, Revision 4, August 19, 1985, "Reactor Trip Review Process."

The specific scope and findings related to each of these areas are addressed below.

7.2 Rules for the Protection of Employees Working on Electrical and Mechanical Apparatus

The stated purpose of AP 1002 is to provide methods to insure the safety of personnel who may be required to work on or around electrical and mechanical apparatus under the jurisdiction of TMI-1. The apparatus covered by the procedure may or may not be radioactive. The procedure is also intended to help assure that equipment tagging and alignments are consistent with nuclear and equipment safety concerns. As stated further in AP 1002, the detailed procedure provides a step-by-step method for the electrical and/or mechanical isolation and control of equipment of which maintenance, inspection, troubleshooting or testing is to be performed.

The inspector reviewed the detailed procedures specified in AP 1002 and verified that adequate controls were in place for switching and tagging operations including appropriate requirements for proper review to be conducted prior to removing equipment from service. However, the inspector noted that the control room operator assigned to switching and tagging activities could approve a tag even though he may not be certified as a switching and tagging initiator. The inspector noted that this apparent inconsistency was allowed by procedure and the number of control room operators not qualified as switching and tagging initiators was minimal. Licensee

representatives stated that their certification practices would be reviewed for appropriate followup actions, and the inspector had no further questions regarding this matter.

In addition to the above procedure review, the inspector randomly selected several active switching and tagging sheets and verified their accuracy. The inspector also determined that the switching and tagging sheets correctly reflected what tags were posted in the plant.

The inspector concluded, based on this review, that the licensee's switching and tagging program and procedures were properly controlling the removal and return of equipment that was required to be tagged out. The comments noted by the inspector were considered to be of a minor nature.

7.3 Control of Caution and Do-Not-Operate Tags

The AP 1037 describes the purpose and control of caution and do-not-operate (DNO) tags. Caution tags are used as an information tag only; not as safety tags for protection of personnel. A caution tag is to be attached to a component, control switch or other device to indicate an off normal condition or to caution personnel to a specific condition which must be satisfied prior to using the component or device. A do-not-operate tag, which is primarily used for equipment protection may be used in place of a caution tag particularly when used in environments where the caution tag may easily deteriorate under extended use.

The inspector reviewed the requirements related to caution and do-not-operate tags, as specified in AP 1037, and determined that the guidance appeared to provide effective administrative controls for using these tags. In addition, the inspector reviewed the caution and do-not-operate tag log books and selected tags in use. Based on this review, the inspector noted only minor potential administrative problems. The procedure established no policy on when to consolidate caution tag log sheet entries, and the operator cannot tell whether a log sheet is removed or lost from the notebook. Also, AP 1037 states that upon removal of a do-not-operate tag, the time (as well as other items) is to be filled in on the log sheet; however, the log sheet does not include a place for recording time. The inspector discussed these observations with licensee representatives and had no further comments regarding this matter.

7.4 Instrument Out-of-Service Control

The stated purpose of AP 1036 is to describe the method of control of read out devices which become inoperable or are strongly suspected of being inoperable such that they are marked, documented and controlled until repair is affected. The procedure applies principally to the control of out-of-service instruments and read out devices which are required by the technical specifications. It applies to meters, gauges, amplifiers and recorders when they become

inoperative or are displaying what appears to be incorrect information.

The inspector reviewed this procedure and verified that a log was being maintained of out-of-service devices, the log reflected actual equipment status, and out-of-service equipment did not or would not have an adverse affect on safe plant operations.

The inspector noted that the number of pieces of equipment out-of-service was minimal. Equipment that has been out of service for extended periods generally was minimal and had no effect on plant operation. Several old out-of-service stickers were still in effect; two since 1977, two since 1981, five since 1983 and five since 1984. However, the average length that a major piece of equipment would remain out of service was short. From the review of the log entries and selected stickers the inspector determined that the licensee's program for control of out-of-service instruments was being implemented.

7.5 Reactor Trip Review Process

The inspector reviewed AP 1063 to ensure that the procedure required the gathering and retaining of key plant parameters and plant records that would identify significant changes and trends of plant parameters that may be indicative of plant performance problems and that the procedure required the necessary safety review and analysis to be performed to ensure the plant could properly restart. In addition, the procedure was reviewed to ensure that noted problems, if any, were properly characterized, tracked and resolved, if necessary, prior to restart.

Implementation of this procedure was verified as noted in paragraph 3.4. The inspector reviewed the data generated to support the post trip review. The inspector determined that the major and significant parameters were being retrieved and recorded. The procedure was structured in a manner that allowed the review group to smoothly move through the checklist in a timely manner. The licensee did note several minor administrative problems that need to be reviewed but which had no significant impact on the overall objective of the procedure. The checklist had the necessary provisions to cause independent reviews to be performed to resolve identified inconsistencies in plant response. Overall, the procedure was determined to be adequate.

7.6 Conclusion

The administrative procedures described above were technically adequate although they could be improved to enhance effectiveness. In general, these procedures were properly implemented.

8. Exit Interview

The inspectors discussed the overall inspection scope and findings with licensee management at the exit interview conducted on October 25, 1985. The following licensee personnel attended the final exit meeting.

D. Carl, Review Program Coordinator, TMI-1
J. Colitz, Plant Engineering Director, TMI-1
S. DiVito, Supervisor Design and Drafting - TMI, Technical Functions
T. Hawkins, Manager, TMI-1 Startup and Test, Technical Functions
H. Hukill, Vice President and Director, TMI-1
C. Incorvati, TMI-1 Audit Supervisor, Nuclear Assurance
M. Nelson, Supervisor, Review Program, TMI-1
S. Otto, TMI-1 Licensing Engineer, Technical Functions
L. Ritter, Administrator II, Plant Operations, TMI-1
M. Ross, Manger, Plant Operations, TMI-1
C. Shorts, Manager Technical Functions TMI-1, Technical Functions
D. Shovlin, Manager, Plant Maintenance, TMI-1
P. Sinegar, Administrator II - Maintenance, TMI-1
M. Snyder, Preventive Maintenance Manager, TMI-1
R. Toole, Operations and Maintenance Director, TMI-1

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

There was an interim exit on October 24, 1985, with the Nuclear Safety and Compliance Committee Staff members (Mr. E. Hammond, et. al.) to discuss the results of the inspection on their activities.

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 3.2.1, 3.2.4, 3.2.5, 3.2.6, 4.2.3, 5.4, and 6.2.