U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No.	50-289/85-28
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:	November 27-December 13, 1985
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Approved By:	R. Conte 1/16/86 R. Conte, TMI-1 Restart Manager Date TMI-1 Restart Staff Division of Reactor Projects

Inspection Summary:
The TMI-1 Restart Staff conducted routine and special (NRC shift coverage) safety inspection (540 hours) of power operation focusing on operator and management performance. Specifically, items reviewed in more detail in the facility operations area were: inadvertent trip from 75% power; reactor power being limited by steam generator level; reactor building pressure sensing instrument lines; diesel generator standby status; and the borated water storage tank/sodium hydroxide storage tank differential level. Special focus continued on completion of startup and power escalation testing for the 75% plateau. Other review items included: radioactive liquid and gaseous effluent control; makeup pump operability; and licensee action on previous inspection findings.

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Inspection Results:
Licensed operators demonstrated their orientation to nuclear safety and their attentiveness to avoiding safety system challenges. Non-licensed operators/technicians also demonstrated an acceptable level of knowledge of the facility design and of their responsibilities. Personnel properly responded to the reactor trip event and the post-trip review. The training department was a key factor in these positive results.

Licensee personnel continued to maintain the facility properly and conduct required surveillance testing as evidenced by the review conducted on the makeup pump operability. In most cases, procedures were implemented properly; however, procedure implementation problems persisted because of incomplete licensee corrective action in response to previous inspection findings in this area. Overall, procedures were adequate as evidenced by the review of the decay heat closed cycle cooling system. Test procedures were properly implemented. Adequate technical support was provided to the startup program, however, a licensee safety evaluation on steam generator high level limit should have initially addressed thermal stress in case of flooding of the steam aspirator parts in the steam generator.

Radioactive liquid and gaseous effluents were handled properly in accordance with regulatory requirements. The licensee's program is well organized with quality control checks and quality assurance department involvement in this area.

The licensee adequately prepared for cold weather in protecting safety-related equipment in outside areas.

DETAILS

1. Introduction and Overview

1.1 General

At the beginning of this inspection period on November 27, 1985, the TMI-1 Restart Staff was providing on-shift inspection coverage 12 hours a day to assess restart operating activities. At 7:00 p.m. on December 1, 1985, continuous coverage was initiated of the plant startup following an unplanned reactor trip that had occurred earlier, and at 4:00 p.m. on December 2, 1985 this inspection coverage was returned to 12 hours a day consistent with the reduced level of testing activity and steady-state facility operation. The staff's observation of plant activities was maintained by NRC personnel from Region I and by a reactor operator examiner from EG&G Idaho, Inc., an NRC contractor. Also, Region I inspectors continued periodic 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 November 27-December 13, 1985, the TMI-1 restart operational activities consisted of continued main turbine generator testing and electric power generation at the 75% power testing plateau. The test period was interrupted for several hours as a result of an unplanned reactor trip on December 1, 1985.

1.3 Operational Events

One event and certain other activities occurred during this inspection period that were considered either operationally significant or of special interest to the TMI-1 Restart Staff. These matters are discussed below.

At 2:11 a.m. on December 1, 1985, a reactor trip occurred while the plant was operating at 75% of rated power. The trip was initiated by activation of the overexcitation relay circuit associated with the main electrical generator. Tripping of this relay opened the generator's output breakers; and, with relatively little energy removal via the secondary plant, reactor coolant system pressure increased until the reactor tripped on high pressure. The post-trip response was as expected except that steam generator pressure in once-through-steam generator (OTSG) 1A was controlled by the main steam safety valves vice the turbine bypass valves. This same occurrence was noted previously during the plant transient after the planned trip at 40% of rated power. The operators took manual control of the turbine bypass valves, lowered main steam pressure, and reseated all safety valves. A replacement overexcitation relay was installed and in-place testing was performed satisfactorily. At the close of the inspection period, the licensee was still evaluating the failure of the original relay.

The reactor was taken critical again at 2:04 p.m. on December 1, 1985. At 4:40 a.m., on December 2, 1985, the reactor was at about 71% of rated power where further escalation became restricted when the integrated control system high level operating limit on OTSG 1A was reached. This problem was due to steam generator tube fouling and it was anticipated by the licensee. The power ascension was stopped at four hold points to obtain steam generator operating performance data. The problem also was discussed in Inspection Report 50-289/85-27.

On December 3, 1985, the licensee completed its evaluation of raising the OTSG high level water limit. The integrated control system was set originally to control the OTSG level to 73% on the operating range although the vendor (B&W) had established an OTSG operating level limit of 82.5%. The licensee concluded that raising the OTSG level limits from 82.5% to 92% on the operating range will not adversely affect plant safety. The licensee decided to raise the setpoint in two steps. First the level limit was set at 82.5% on December 3, 1985, where it remained until the completion of the 75% power plateau testing. Moving the setpoint to 92% was planned prior to escalating to the maximum power achievable with this new setpoint. At 6:40 p.m. on December 3, 1985, power was increased to 75% of rated power.

1.4 Summary

This inspection included restart testing activities at the 75% power plateau. During this period there was one interruption of the restart testing period, as a result of an unplanned reactor trip. The shift inspectors referred only implementation matters or status questions to shift supervisory personnel and referred programmatic matters (event followup, design or procedure adequacy problems) to resident and region-based NRC personnel. Resident and region-based personnel interfaced with licensee support groups in followup to shift inspector referrals/concerns. The staff's observations and findings regarding plant operations and testing and licensee response to operational events is discussed in the report sections that follow.

2. Shift Inspection Activities

2.1 Scope of Review and Observations

During the period of November 27-December 13, 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/observations 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

-- shift turnover activities conducted by licensed operators and operating crew planning briefings conducted by shift foreman

-- shift crew performance of powdex regeneration operations

-- water addition to core flood tanks

-- various radioactive liquid and gaseous waste discharges from the plant

-- crew response to erroneous indication of Group 1 Rod 8 position - near bottom of core vice the actual fully withdrawn position

-- various water additions (deboration) to makeup tank to establish and maintain desired imbalance and Group 7 rod positions

-- operating crew preparations for and conduct of taking the reactor critical on December 1, 1985

-- turbine generator startup and power escalation to 30% of rated power, followed by gradual increases to 40%, 48%, 65%, and 71% of rated power

-- power increase from 71% to 75% of rated power

-- hydrogen addition to the main generator

-- operator response to once-through steam generator 1B high level alarm when the opposite level transmitter was selected for operational check

-- control room operator removal from service of heater drain pump 1C in response to abnormal operating conditions

-- operating crew response to ventilation fan AH-E-20A access cover found open by the NRC shift inspector

Periodic Surveillance and Maintenance Testing

-- portions of reactor protection system monthly surveillance per procedure 1303-4.1

- portions of main steam line radiation monitor surveillance per procedure 1303-4.21

-- periodic reactor coolant system leak rate measurements

-- source range nuclear instrumentation surveillance per procedure 1303-7.2

-- operations department surveillance for winterization checks per procedure OPS-S-85, completed October 4, 1985

-- testing and troubleshooting of effects of pressurizer power operated relief valve setpoint surveillance causing spiking of pressurizer level indication

-- portions of radiation monitoring system periodic surveillance testing

-- testing and troubleshooting of letdown radiation monitor RM-L1, interlock associated with letdown cooler isolation valve

-- control rod movement tests per procedure 1303-3.1

-- core performance monitoring per operations surveillance procedure OPS-S-108

-- calibration of steam flow transmitter for turbine-driven emergency feedwater pump EF-P-1A

-- portions of calibration of Eberline iodine monitor type IM-1A per procedure 9000-PMI-4224.03

-- calibration of steam generator level transmitters

-- operational test of turbine-driven emergency feedwater pump EF-P-1A per procedure 1300-AG A/B

-- post-maintenance operational test of condensate booster pump 1C

Preventive and Corrective Maintenance Activities

-- troubleshooting and repair of instrument air compressor 1B breaker that licensee personnel had found tripped

-- troubleshooting and replacement of main turbine generator overexcitation relay that had initiated reactor trip on December 1, 1985

-- adjustment of once-through steam generators 1A and 1B high level limit setpoints to 82.5% of the operating range

-- repair of condensate booster pump 1C oil leak

-- cleaning of electrical distribution panels

-- operator verification of "application for taking equipment out of service" for repair of valve SF-V-7

-- selected equipment tags and portions of maintenance related to resetting relief valves for turbine-driven emergency feedwater pump EF-P-1A

-- troubleshooting of once-through steam generator 1A operating level transmitter differences

-- replacement of overheating outboard seal for EF-P-1A

-- investigation and troubleshooting of metal shavings found in discharge of river water pump

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

-- posting practices for radiation work permits and weekly radiation area survey maps

-- problems encountered by switching and tagging reactor operator when attempting to return the emergency backup instrument air system to service without either knowledge of how to perform the task or use of the procedure

-- operating staff post-trip review of unplanned reactor trip that occurred on December 1, 1985

-- trending of reactor coolant system leak rate measurements following the unplanned reactor trip

-- operating personnel control of fire doors

-- practices for display of personnel identification security badges

-- valve lineup for decay heat closed cooling water system

-- locked high radiation area access controls

-- implementation practices regarding temporary change notices for procedures

2.2 Assessments of Shift Inspectors

2.2.1 General

The shift inspectors assured that any potentially adverse safety concern or regulatory finding was identified promptly to both appropriate licensee supervisors and the NRC's TMI-1 Restart Manager. Those items requiring additional staff review or followup are described in paragraph 3 of this report. Also, at the end of their assigned period of shift inspection activities, the inspectors provided their general assessment of facility operational readiness and personnel performance. As noted below, these general findings included, as applicable, the collective inspector views related to operating staff performance, maintenance, surveillance, radiological controls, training, emergency planning, and physical security. The overall conclusions of the TMI-1 Restart Staff are provided in the sections that follow.

2.2.2 Operating Staff Performance

Observations of steady-state operations continued. Operations personnel appeared to be well motivated and continued to exhibit a professional and attentive attitude. Although activity level was low, there were several routine surveillance and corrective maintenance activities that took place. These activities were handled in a controlled manner with personnel using their knowledge of plant systems.

The watch reliefs (shift turnovers) observed were conducted quietly and thoroughly with a subsequent briefing of auxiliary operators to ensure all personnel were aware of plant conditions and expected evolutions.

Operations management was involved with retest activities after corrective maintenance. Two observed examples were the testing of the steam-driven emergency feedwater pump and the "C" condensate booster pump on December 11, 1985.

Auxiliary operators (AOs) appear to be well trained. AOs were observed on several occasions making tours of assigned areas and checking equipment. One AO noted an abnormal noise on a heater drain pump. Maintenance and operations personnel, including management, listened to the pump and decided to place it out of service for corrective maintenance.

In most cases, procedures were properly implemented. However, additional examples of the procedure implementation problems were noted. These problems were described in detail in Inspection Report 50-289/85-27, paragraph 3.2.11, in which an apparent violation of NRC requirements was identified.

For example, on November 30, 1985, a licensed operator (switching and tagging CRO) attempted to restore a EFW backup instrument air bank to service following a switching and tagging order. The system has an automatic depressurization mechanism (3-way valve) that assures positive depressurization of the system when pressure decreases to approximately 60 psig (this guarantees that system load valves, designed to fail open, do so when depressurization occurs). The applicable operating procedure (OP 1104-25, step 3.6.2) described in detail the steps needed to override the automatic depressurization 3-way valve in order to pressurize the system for standby operation. Apparently the operator was weak in his knowledge of this system and he did not use or refer to the applicable section of OP 1104-25 in order to repressurize the system. After several repeated attempts at pressurization, the operator consulted with the shift supervisor who knew how to pressurize the system but who also did not use the applicable procedure. The procedural steps were correctly implemented from memory and the instrument air bank was returned to service.

As an additional example, on a secondary plant component, on December 4, 1985, auxiliary operators attempted to place a hydrogen supply bank in service for the main generator hydrogen cooling system. The standby bank apparently was used for TMI-2 and the in service bank apparently had a leak. The applicable operating procedure (1106-8) did not have provisions for using the second bank since it was reserved for TMI-2 (which no longer needed it). The AOs then performed a lineup using a system drawing. Pressurization attempts failed because a cross-connect valve was not opened. This was another example of failure to establish procedures.

Although the later example dealt with a non-safety system, in discussions with licensee management the TMI-1 Restart Staff focused attention on the adverse effects that could have resulted in a primary system transient had an inadvertent release of hydrogen occurred because of an improper valve lineup.

Further, on December 10, 1985, operators completed a switching and tagging order in preparation for placing the EFW turbine-driven pump out of service. The operators signed and dated the tags as being hung at 1:00 p.m. on December 9, 1985, when in reality the tags were not hung until 5:57 a.m. on December 10, 1985. Other facility records indicated the actual out-of-service time for the EFW pump, but the inspector indicated that the tag records could cause confusion as backup records of out-of-service time. The problem was the apparent inflexibility of the AP 1002 which required that the tags be signed and dated when filled out. The licensee representative submitted a change to AP 1002 in order to provide additional flexibility such that tags could be prepared in advance and signed/dated when actually hung. The inspector had no further comments in the area of procedure implementation.

The inspector also noted a poor document control practice. Of 15 procedure temporary change notices (TCNs) reviewed, not all TCN pages were numbered. It became unclear what order and how many pages were required to be with the TCN package. The inspector noted no instances of missing pages. Licensee representatives acknowledged the comment and indicated they would review this practice and consider changing it to enhance document control measures.

2.2.3 Training

In general, shift inspector observations indicated that the training department provided sufficient knowledge and assured demonstrated skills to support the performance of activities in a safe and professional manner. The procedure implementation problems described above suggest that additional management attention is needed in assuring its procedure adherence policy is implemented.

A primary focus during this inspection period continued to be the implementation of the licensee's restart training programs for licensed operators (NRC Inspection Items 289/81-33-04 and 289/84-19-01).

Shift inspectors continued to conduct interviews of the operating crews to assess the performance-oriented aspects of their knowledge of facility design and operations. At the close of this inspection period, a total of four senior reactor operators and ten reactor operators covering all six shifts were interviewed. The interviews began in NRC Inspection 50-289/85-26 and continued in NRC Inspection 50-289/85-27. The questions asked were performance oriented in the areas of primary system operation and power operations/maneuvering, since these had the most applicability to the present plant configuration.

The overall knowledge level in these areas was considered average or above, as determined by the NRC examiners' expectations. There were no areas of unexpected poor knowledge. Although isolated weaknesses were identified none of these warranted immediate licensee corrective action. Observations of licensed operator performance throughout the power escalation program including the recent reactor trip (based on a post-trip review) substantiated these findings. It appears that the training department was a key factor in enhancing operator knowledge and performance in preparation for restart. Overall, licensed operators performed well and they demonstrated their orientation toward nuclear safety and avoiding safety system challenges.

2.2.4 Maintenance

The licensee appeared to have a well-defined maintenance program. Activities are controlled and planned. Several maintenance activities of special interest were the repair of the steam-driven emergency feedwater (EFW) pump, the "C" condensate booster pump, and troubleshooting of the "A" OTSG level indicators. Management was involved in these areas as well as others. Daily meetings were held to determine status and to plan/schedule additional maintenance activities. Quality assurance department involvement was also noted during testing of the EFW pump. The licensee displayed a cautious attitude by securing the EFW pump when its outboard packing became excessively hot. Subsequently, they replaced the packing, and examined and corrected a minor defect in the packing gland assembly lantern ring.

There was another case of a worker having the potential to adversely affect plant operation. The duct access cover on the discharge of fan AH-E-20A in the control building was left off and the ducting was open. The shift supervisor had the door reinstalled when the inspector brought it to his attention.

2.2.5 Surveillance

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

2.2.6 Fire Protection

During inspection of the safety-related areas, shift inspectors noted several occasions where labelled fire doors were "ajar" (not fully closed, leaning on the latch mechanism). This was noted on five occasions with door C-207 in the control building. On other occasions, other fire doors were noticed ajar. It appeared that the doors had a problem with their closing mechanisms and personnel were not attentive enough to assure proper closing of the door upon passage through the door. Licensee management indicated that the fire doors were a resource-intensive maintenance item to keep up with and that a preventive maintenance procedure was in place to keep track of and correct fire door problems.

The TMI-1 Restart Staff will continue to routinely follow this item and, in particular, the staff will review this area in the next inspection period to assure proper licensee control of fire doors.

2.2.7 Radiological Controls

The radiological controls program appears to be well established. Procedures and practices were properly implemented. Several outdated radiation work permits (RWPs) were still posted near the Unit 1 health physics control point but no instances were identified where an individual signed in on an outdated RWP.

2.2.8 Physical Security

The inspectors identified an additional example of improper implementation of security badge control measures as described in detail in Inspection Report 50-289/85-27, paragraph 6, in which inspectors identified an apparent violation of NRC requirements.

2.3 Conclusion

Overall, personnel conducted themselves in a professional manner. Licensed operators demonstrated their orientation to nuclear safety and their attentiveness in avoiding safety system challenges. Non-licensed operators/technicians also demonstrated an adequate knowledge of facility design and their responsibilities. The training department was a key factor in these positive results. In most cases procedures were properly implemented. However, the implementation problems noted in the past two inspection periods persisted to a lesser extent probably due to incomplete licensee corrective actions. Licensee personnel and management continued to properly maintain the plant and conduct surveillance testing on the facility. A problem was noted with fire doors remaining ajar and this area will be reviewed further during the next inspection period. With the fire door examples and another example, the worker-in-the-spaces problem persisted but with minimal impact on plant operations or safety.

3. Plant Operations

3.1 Scope of Review

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

-- review of selected plant parameters for abnormal trends

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

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

-- control of documents including logkeeping practices

-- implementation of radiological controls

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

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

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

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

-- areas outside the control room

-- selected licensee planning meetings

The inspectors reviewed specific events in more detail as described in the sections that follow.

3.2 Findings

3.2.1 General

Licensee management was involved in all phases of plant operations, and there was sustained evidence of quality assurance department attention. The operations manager directed overall daily plant activities while shift supervisors were held responsible for accomplishment of directives. Inspectors noted that during several of the plant maneuvers the operations manager took direct control with the shift supervisor and shift foreman assisting. (The operations manager is a licensed senior reactor operator with extensive experience at TMI-1.) The TMI-1 Restart Staff considered that the operations manager appropriately exercised this control prerogative in light of the special evolutions, unique testing and outside focus on the facility.

The staff anticipates that subsequent to the power escalation program the operations manager will exercise this prerogative to a lesser extent which will allow shift supervisory personnel to demonstrate and exercise their skills in off-normal or unique situations as they occur.

3.2.2 Inadvertent Reactor Trip From 75% of Rated Power

3.2.2.1 Introduction

On December 1, 1985, with the plant operating at 75% of rated power, a reactor trip was initiated by activation of the overexcitation relay circuit associated with the main electrical generator.

3.2.2.2 Event Review

The TMI-1 Restart Staff reviewed the event to determine the following information:

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

-- functioning of safety systems as required by plant conditions

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

-- radiological consequences (onsite and offsite) and personnel exposure, if any

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

-- verification that plant and system performance are within the limits of analyses described in the Final Safety Analysis Report (FSAR)

To assess the event, the inspector discussed the matter with cognizant licensee personnel and reviewed the following documents:

-- control room operator's and shift foreman's log for the day of the event

-- abnormal transient procedure (ATP) 1210-1, "Reactor/Turbine Trip," Revision 9, dated March 19, 1985

-- operating procedure (OP) 1103-75A, "Shutdown Margin and Reactivity Balance," Revision 1, dated October 26, 1984

-- OP 1063, "Reactor Trip Review Process," Revision 4, dated August 19, 1985, and its applicable enclosures

3.2.2.3 Chronology of Event

The plant conditions prior to the trip were, RCS pressure 2155 psia, Tave 579 F, RCS boron concentration 786 ppm, all four reactor coolant pumps (RCPs) running, pressurizer level at 221 inches, normal letdown and makeup in progress using one makeup pump and total effective full power days (EFPD) equal to 23 days. The plant had been at 75% rated power for the eight days prior to the trip.

The reactor trip was initiated by activation of the overexcitation relay circuit opening the main electrical generator output breakers. The overexcitation relay monitors the main electrical generator's output voltage compared to output frequency (volts to Hertz ratio). If the ratio is too high, internal wiring damage could occur to the main electrical generator's transformer, or in extreme cases damage the main electrical generator's field windings.

With no energy removal via the secondary plant, reactor coolant system pressure increased causing a reactor trip on high reactor coolant system (RCS) pressure (2305 psia) at 2:11 a.m. Above 20 percent power a turbine trip will cause a reactor trip; the high pressure reactor set point was achieved first and caused the reactor trip at 2:11 a.m. before the reactor could respond to the loss of the main generating turbine.

The control room operators immediately began to perform action steps of ATP 1201. An alarm was recorded on feedpump turbine 1A loss of oil pressure. This circuitry is also used to activate a reactor trip on loss of both feedwater pumps. This alarm was considered spurious by the operator as feed pump 1A was still running. As part of ATP 1201, the operators started a second makeup pump to limit level decrease in the pressurizer. Due to a decreasing pressurizer level, an operator opened the suction valve from the BWST (MU-V14) and opened the high pressure injection valves MU-V16s (i.e. the operator manually initiated high pressure injection) to restore pressurizer level. Pressurizer level reached approximately 55 inches (decrease from an initial level of 221 inches) and RCS pressure decreased to 1820 psia (decrease from an initial pressure of

2155 psia) before high pressure injection started to recover pressurizer level and pressure. As pressurizer level began to recover, the control room operators secured the high pressure injection lineup and returned to the normal makeup lineup.

During the transient, the main steam safety valves (safeties) on both steam generators initially lifted. The main steam safeties on the B steam generator appeared to reseat and the turbine bypass valves associated the B steam generator automatically took over and regulated the pressure in the generator. On the A steam generator the main steam safeties continued to lift and reseat several times thus controlling the pressure in the A steam generator. Approximately 15 minutes after the trip, the shift supervisor directed manual control of the A turbine bypass valves to lower steam pressure to below safety valve setpoints.

After the plant was stable, the shift supervisor made the required notification to the NRC headquarters duty officer at approximately 3:11 a.m. The shift supervisor also notified the senior resident inspector. The NRC Restart Staff members were onsite at 6:00 a.m. to temporarily re-establish continuous NRC inspection coverage, to review the trip event and to witness the restart of the plant. At 7:00 a.m., the licensee conducted a post-trip review meeting in accordance with AP 1063. The inspector attended portions of the post-trip review. After completing the necessary actions and reviews, the licensee restarted the plant at 12:00 noon. The reactor achieved criticality at approximately 2:14 p.m. The plant was then escalated to 71% rated power where the plant power output became limited by the steam generator water high level limit.

3.2.2.4 License Review/Findings

The licensee documented its review of the event by performing a post-trip review per AP 1063. The review provided for data collection of specific plant parameters; determining sequence of events and root cause of the trip; evaluation of plant response during the transient; and identification of corrective actions required prior to restart. The licensee concluded that the trip was due to activation of the overexcitation relay circuit. Preliminary data indicated that the setpoint for this relay was too low. Review of the electrical distribution grid indicated that grid voltage (which is controlled by utilities load dispatcher in Lebanon, Pennsylvania) had drifted towards the high end of the operating band.

With the voltage drifting high and the setpoint low, the relay activated as designed. The reason that the relay setpoint was too low was still under evaluation by the licensee at the close of the inspection period. The relay itself was replaced with a spare relay and satisfactorily tested in place.

Replacement of the relay and satisfactory testing of this and other similar relays was a licensee identified prerequisite for startup. The licensee review of plant parameters indicated that the plant response was as expected, except for intermittent lifting and reseating of main steam safety valves on the A steam generator; some difficulty in starting up the auxiliary boiler; and the spurious alarm on the main feed pump lube oil pressure. The licensee also was evaluating the steam generator safety valve problem because of previous test results (see NRC Inspection Report 50-289/85-22 for more details).

The inspector also reviewed applicable documentation to determine if the plant transient had caused a significant radiological problem. This review determined that the inadvertent release via the steam generator main steam safeties was minor. This and other types of releases were closely reviewed and are further detailed in section 5 of this report.

3.2.2.5 NRC Review/Findings

At 6:00 a.m. that day, the TMI-1 Restart Staff initiated its review of plant and personnel response to the reactor trip. The inspector initially reviewed control room indicators and recorder charts for the time of the trip. Also, he attended portions of the licensee's post-trip review. The graphs and plots of plant parameters were reviewed to ensure that the plant responded as expected. Portions of the in-place testing of the new relay and associated relay testing were witnessed.

The inspector concluded that the licensee's post-trip review had identified the root cause of the trip; all inconsistencies in plant response had been identified; and restart of the unit was supported by the licensee's review. Noted deficiencies were either corrected prior to restart or adequate resolution had been determined to support restart. The licensee is still in the process of preparing a licensee event report (LER) and this event will remain open until NRC review of the LER (289/85-LO-03).

The inspector witnessed portions of the startup and reviewed the applicable documentation. The plant startup and return to power were performed per applicable procedures. Due to steam generator level limitation, the plant was only able to reach 71% of rated power, as opposed to 75% of rated power prior to the trip.

3.2.3 Steam Generator Level Limits

During normal operation, the feedwater enters the secondary side of the steam generator through feedwater nozzles. It is sprayed into a downcomer annulus between the shell and the cylindrical baffle that surrounds the straight tube bundle. The momentum energy of the high-velocity spray stream of feedwater and the gravity head of the downcomer water level provide sufficient head to drive flow through the steam generator. As the steam generator load increases (above 15% power level) the level of water in the downcomer also increases.

Ever since the plant escalated power from the completion of 40% power reactor trip test (TP 800/2), it has been noted that both OTSG water levels have increased linearly with increased reactor power at a higher-than-expected slope. The greater than expected rise of steady-state steam generator water level with time for a given reactor power is not unique to TMI-1, this condition has occurred in other B&W facilities with a once-through steam generator (OTSG) design. The problem is attributed to fouling of the secondary side heat transfer surface over a long period of time and/or flow resistance increase due to deposits building up between tubes and tube support plates. Consequently, a higher steam generator water level is needed to transfer the same amount of heat.

In the downcomer region, the incoming feedwater is preheated to saturation temperature by the bleeding steam from the tube bundle; this mitigates thermal stresses on the lower steam generator components. The then current ICS high steam generator level limit was set at 83% of the OTSG level operating range (0-100%) in accordance with B&W's original recommendation. This limit provides sufficient margin for preventing downcomer flooding, and thus assures proper feedwater preheating in the downcomer region. TMI-1 was operating at 75% of rated power (71% after the trip) with OTSG water level at approximately 74% on the operating range. With the limit of 83% on steam generator water level, the reactor power would be limited to approximately 82% after power escalation. The licensee's plant engineering group, with assistance from B&W, prepared a safety evaluation (in accordance with 10 CFR 50.59), No. SE-000224-003, to determine the acceptability of increasing the OTSG operating level range limit from setting of 83% to 92%. The licensee's review determined that raising OTSG level limit is acceptable and does not constitute an unresolved safety question.

The NRC TMI-1 Restart Staff independently reviewed the licensee's safety evaluation and determined the following:

-- Sufficient subcritical margin (0.4% delta K/K) exists for the main steam line break analysis. The new operating range (92%) is still bounded by the safety analysis in the TMI-1 FSAR.

-- Downcomer flooding is not expected to occur even assuming the feedwater nozzle is in a less-than-optimum condition due to nozzle erosion and cannot attain maximum feedwater momentum in the downcomer.

-- Plant instruments are available to detect the condition of downcomer flooding. These include downcomer RTDs, main steam line RTDs, and process computer display/alarm. Discussion with a reactor operator and a shift technical advisor indicated that operations staff personnel were knowledgeable in utilizing these instruments to detect undesirable conditions in the downcomer region.

-- Upon the inspector's request, the licensee performed an additional thermal stress analysis for the lower tube sheet and the lower vertical cylindrical baffle plate in case of aspirator port blockage due to high level in the downcomer region. This stress analysis was not considered in the original safety analysis. The calculated total stresses based on the postulated downcomer flooding condition were still within the ASME Section III allowable limits.

Also, the TMI-1 Restart Staff contacted other NRC resident inspectors assigned to B&W facilities, which have OTSG high water level limit set at 92% or greater. Discussions with these NRC inspectors indicated that no operational problems had been identified at these facilities as a result of the higher OTSG level set points.

Based on the above, the inspector concurred with the licensee's conclusion that no unreviewed safety questions were involved. This area will continue to be reviewed during full power operations.

Further, during the period December 1-13, 1985, the licensee observed a difference in level readings between steam generator "A" operating range level indicators LT2 and LT3. The system was configured such that either LT2 or

LT3 was selected to be recorded and fed to the integrated control system (ICS) for high and low level limits with the other transmitter being automatically fed to the plant computer for on-demand indication. During weekly surveillance checks the levels are compared with each other. A review of the weekly surveillance indicated that LT3 agreed with LT2 on November 30, 1985. The subsequent surveillance conducted on December 7, 1985, indicated that LT3 read 3.8% higher than LT2. This error had increased to about 7% by December 11, 1985. A comparison between steam generators "A" and "B" indicated that LT2 for the "A" steam generator agreed with LT2 and LT3 level readings on the "B" steam generator.

During the following week the licensee performed calibration checks of both LT2 and LT3 level transmitters for the "A" steam generator. Both level transmitters met calibration checks. The licensee also noted that LT5 ("A" steam generator startup range level transmitter) also read high by an amount that corresponded to the LT3 error. Since both level transmitters share the same reference leg it appeared that a small leak in the internal or external equalizing valves could be causing the reference leg to slowly drain and in turn indicate an erroneously high level.

The licensee subsequently isolated both LT3 and LT5 with the equalizing valves closed. The level transmitter outputs were then trended on the plant computer trend recorders. The transmitter outputs indicated a continuously increasing level indicating that either the internal or external or both equalizing valves were leaking. On December 13, 1985, the licensee replaced the internal equalizing valves of both level transmitters and backfilled the reference leg. The level transmitters were then placed in service and their outputs trended on the plant computer trend recorders. On December 16, 1985, the output of both LT3 and LT5 agreed with the output of LT2 and LT4 on the "A" steam generator indicating that the internal equalizing valves leakage had caused the previously observed level differences.

The licensee took appropriate corrective action for the instrument malfunction and the inspector had no further comments in this area.

3.2.4 Reactor Building Pressure Sensing Instrument Lines

An inspection of the reactor building pressure sensing instrument lines was conducted in response to four concerns raised by an NRC shift inspector. These concerns were:

(1) Ability to determine if the reactor building pressure sensing instrument lines are closed, plugged or defective upstream of pressure switch isolation valves.

(2) Adequacy of connecting a non-safety/non-seismic system (instrument air) to the reactor building pressure sensing instrument lines.

(3) Consequences of closing one valve (BS-V37A, B or D) that renders one switch on both the A and B trains of the reactor building spray and reactor building isolation systems inoperable.

(4) Test tee caps removed for calibrations are not independently verified as replaced after test completion even though they are a containment boundary and if left off would render the pressure switch inoperable.

As part of this review, the following documents were examined.

-- GAI drawing C-302-712, "Reactor Building Spray," Revision 19, August 24, 1983

-- SP 1302-5.7, "High Reactor Building Pressure Channel," Revision 8, dated May 7, 1985

-- SP 1302-5.10, "Reactor Building 4 psig Channel," Revision 12, dated May 23, 1985

-- SP 1302-5.11, "Reactor Building 30 psig Channel," Revision 7, dated May 23, 1985

-- SP 1303-11.18, "R.B. Local Leak Rate Testing," Revision 33, dated November 14, 1985

-- OP 1101-3, "Containment Integrity and Access Limits," Revision 37, dated October 18, 1985

When SP 1302-5.7, 5.10 and 5.11 are performed, isolation valves directly in front of pressure switches are closed.

The test tee caps on the tee fittings between the isolation valves and pressure switches are removed, and pressure sources are connected at the test tee connections. This method works well for calibrating reactor building pressure switches. If the pressure sensing lines were closed, plugged or defective upstream of the isolation valves, safety functions performed by these switches may be delayed or absent.

Procedure 1101-3, "Containment Integrity and Access Limits," provides initial and independent verification that all four blank flanges are open. Figure 3, "Indication of Normally Open Blank Flange," depicts how the flange and cover should be bolted to ensure that an open condition exists. SP 1303-11.18, "R.B. Local Leak Rate Testing," provides for leak testing of the various pressure instruments, compression fittings, valve packing and gaskets, etc. that are associated with the detection of reactor building pressure. This procedure tests the entire system from the flanges inside the reactor building to the pressure switches. By performing OP 1101-3 and periodically performing SP 1303-11.18, an adequate means of ensuring that the reactor building pressure sensing lines are not closed, plugged or defective is provided. This resolves concern No. 1.

The instrument air system is connected to the reactor building pressure sensing lines to provide a means of testing the pressure switches' set points from the control room. Since this system is non-seismic/non-safety, some problems may arise. For example, inadvertent actuation of the pressure switches may occur, additional vent paths may be created, instruments may become inoperable and channel separation criteria may be questionable. The shift inspector concluded that the common instrument air supply line to the reactor building pressure switches should be isolated by locking closed IA-V144 (normally open).

After researching this issue, the licensee representatives reported that valves downstream of IA-V144 (IA-V242, 243, 244, 245, and six solenoid valves) that separate the two systems are safety grade, seismically qualified and normally closed. Since these ten isolation valves are safety grade, seismically qualified and normally closed, IA-V144 need not be locked closed to assure the reactor building pressure sensing lines are not degraded by being connected to a non-safety/non-seismic system. This resolves concern No. 2.

If BS-V-37A, B or D is closed, one pressure switch on each train (A and B) of the reactor building spray system and 30 psig reactor building isolation system becomes inoperable. These systems are designed to be two-out-of-three logic actuated systems. If one group of pressure switches is unintentionally valved out of service, the system actuation now becomes a two-out-of-two logic; this logic is less reliable than a two-out-of-three logic. Procedure 1101-3 provides initial and independent verification that BS-V37A, B and D are locked open. This adequately assures that a string of reactor building pressure sensors are not inadvertently isolated by closing a single valve. This resolves concern No. 3.

When test tee caps are removed for performing calibrations in accordance with SP 1302-5.7, 5.10 and 5.11, they are not independently verified as being replaced. If these test tee caps were not replaced and tightened, a direct path from containment to the auxiliary building would be created. Also, the pressure switches' safety functions would be lost because reactor building pressure would escape before reaching the pressure switches.

Currently, the licensee does not have any controls to assure that these test tee caps are securely replaced after surveillance. These caps should appear on the independent verification checklist for each applicable surveillance procedure or appear on OP 1101-3, "Containment Integrity and Access Limits." The licensee's actions to address this concern will be evaluated in a future inspection report related to the issue of independent verification of equipment control measures addressed in NRC Inspection 50-289/85-27 (289/85-28-01).

After reviewing the issues associated with the reactor building pressure sensing instrument lines, the inspector concluded that licensee procedures and equipment were adequate to resolve concern Nos. 1, 2 and 3. Licensee action in response to concern No. 4 will be evaluated in a forthcoming inspection report.

3.2.5 Diesel Generator Standby Status

During the course of the annual diesel generator preventive maintenance conducted on both emergency diesel generators during November 1985, a potential problem with check valves in the diesel cooling water systems was identified for diesel generator EG-Y-1A as documented in Inspection Report 50-289/85-26 (unresolved item 289/85-26-05). During the inspection and examination of the check valve (EG-V48A), it was observed that the check valve may not be fully closing with existing spring force and could preclude proper operation of the diesel "keep warm" system.

Subsequent observations of the diesel cooling piping and jacket coolant temperature indicators, by the inspector, revealed that piping in the coolant system that should have been cool (at ambient) was actually as warm as the surrounding piping that was being heated by the diesel "keep warm" heating system. This indicated that the check valve EG-V48A was potentially leaking. This condition also was observed for the 1B, EDG at valve EG-V48B. Temperature indicators TI-J504 A&B also indicated temperatures of approximately 112 F to 113 F vs. the 120 F to 140 F required range indicated in the auxiliary operators log. Shift auxiliary operators had also logged readings that were out of specification during periods of time in November and December.

The inspectors discussed this information with licensee maintenance and engineering staff to determine if the low temperatures in the diesel "keep warm" system would prevent improper operation and loading of the EDGs. Licensee engineering staff responded that the "keep warm" system was used to maintain elevated lube oil temperatures to lessen wear on diesel engine components that could eventually lead to failure of these engine parts, e.g. crank shaft, pistons and bearings, and that starting the diesel with lower lube oil temperatures would not affect the starting or loading times of the EDG.

Maintenance personnel have ordered new check valves to replace the ones that appear to be leaking and will accomplish this repair when the parts arrive on site. Although 289/85-26-05 is closed, the standby status of the diesel generator will continue to be routinely reviewed.

3.2.6 Borated Water Storage Tank/Sodium Hydroxide Storage Tank Differential Level

The inspector reviewed the method for determining the differential level between the borated water storage tank (BWST) and the sodium hydroxide storage tank (SHST). Technical specification 3.3.1.3.b requires the SHST level to be maintained between 7.5 feet and 8.5 feet below the BWST level using a differential pressure indication. Compliance with this technical specifications assures equal draindown of both tanks during a reactor building spray event.

As part of this review, the following documents were examined.

-- TMI-1 technical specifications

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

-- licensee calculations used to develop Table 1, "Allowable BWST/SHST Differential Pressure," in SP 1301-1

The licensee uses a differential pressure indicator to determine if they are in compliance with technical specification 3.3.1.3.b; therefore, densities, temperatures, concentrations, and tank levels should be used to accurately determine differential pressures.

The licensee's calculations take into account variances in BWST level, SHST differential level, and SHST concentrations; they do not account for variances in BWST concentrations, and BWST/SHST temperatures. The inspector questioned a licensee representative concerning their assumption to treat these three variables as constants. The licensee representative stated that BWST concentration remains fairly constant and the tanks are kept between 40 F and 90 F; therefore swings in temperature will not adversely affect the calculations.

The licensee's method for determining tank differential level using differential pressure readings was found to be correct. The inspector then calculated how variances in BWST concentrations and BWST/SHST temperatures affected the calculations. The licensee assumes the BWST specific gravity to be 1.0035 and the SHST specific gravity to vary between 1.1005 and 1.1165 (depending on SHST concentrations). The inspector determined that temperature differences could cause the BWST specific gravity to vary between 1.0025 to 1.0075 while temperature and concentration differences would cause the SHST specific gravity to vary between 1.1027 and 1.1135. The inspector agreed that boron concentration remains fairly constant and therefore, specific gravity fluctuation would be insignificant.

The inspector performed various calculations using different temperatures and SHST concentrations to compare licensee uncompensated temperature differential pressures with compensated temperature differential pressures. The differences were found to be small and not significant (errors less than two inches in tank differential level).

The inspector determined that the licensee's method for complying with technical specification 3.3.1.3.b is acceptable. Even though the licensee does not account for temperature variations, differential pressure errors were minimal. The use of Table 1, "Allowable BWST/SHST Differential Pressure (in wc)," from SP 1301-1 reasonably assures compliance with technical specification 3.3.1.3.b.

3.3 Conclusion

In general, licensee management and the quality assurance department continued their involvement in site activities. Licensee management and operating personnel continued to demonstrate overall control during power escalation and steady-state operations. Personnel conducted themselves in a competent manner during the recovery action from the inadvertent reactor trip and during the post-trip review process. The licensee's safety evaluation for the increase in steam generator level limit initially did not consider thermal stress aspects related to feedwater heating by aspirator steam. However, the licensee was responsive to NRC concerns and produced an adequate 10 CFR 50.59 evaluation on raising the steam generator high level limit.

4. Startup Testing

4.1 Power Level Plateau Data Review

Test results from the test program for the 75% 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 properly identified, resolved, and resolution accepted;

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

-- test results met established acceptance criteria or deviations were properly resolved.

The startup tests reviewed for this verification included:

-- TP 846/1, "Incore Thermocouple Functional Test at Power," (75%);

-- RP 1550-01, Enclosure 1, "Incore Detector Testing"; and,

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

The details and findings of this review are described below. The results of other tests performed at the 75% power plateau and reviewed by the inspector were documented in the NRC Inspection Report 50-289/85-27.

4.2 Findings

4.2.1 The incore thermocouples (T/Cs) were checked at the 75% power level per procedure TP 841/1; four out of fifty-two T/Cs, identified as out of service during earlier testing, remained out of service during this test. The inspector noted the following test results:

- -- The readings from eight inner and eight outer ring symmetrical T/Cs agreed within +/- 1% of the individual symmetrical group average readings. Also, the readings from paired symmetrical locations agreed with each other within the allowable tolerance of +/- 1%.

- -- Actual T/C readings agreed within +/- 2% of the calculated values based on expected temperature distribution in the core. The expected temperature profile was derived from core power distribution which was measured by incore neutron detectors.

- -- At 75% power level, the temperature difference among the nine hottest incore T/Cs was only 2.1 F. The highest T/C reading (608.1 F) and the general locations of the five highest T/C readings (among inner symmetrical ring) were consistently indicated by the computer program designated "TCDSPL" and the mod comp computer. However, due to the quasi-steady nature of these readings, the five highest incore T/C readings as selected by the program "TCDSPL" did not completely agree with the five highest T/C readings from the mod comp computer which were taken at a different time. This matter was also noted in the lower power test results. This will be followed up during testing at a higher power level.

- -- The plant computer uses the program "TCDSPL" to select the five highest incore T/C readings and calculate the saturation margin. The accuracy of selection and calculation was verified through this test.

- -- The backup incore readout (BIRO) thermocouple display in the control room and the value read from the plant computer were consistent and agreed within the established acceptance criteria of +/- 16 F.

4.2.2 Core Power Distribution Verification

The detailed core power distribution at the 75% power plateau was measured by the licensee per procedure RF 1550-08, "Core Power Distribution Verification," using the incore detector system. The inspector noted the following results:

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

- -- 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 (1.288) at core location K-11 agreed closely with the predicted value of 1.285.

-- The measured total peaking factor in each fuel assembly also agreed consistently with the predicted value. The highest measured total peaking factor of 1.483 at core location L-10 agreed well with the predicted value of 1.386.

-- The measured linear heat rates accounting for various uncertainty factors were within technical specification 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	5.10	15.20
9.43	8.66	16.26
7.71	9.07	17.10
6.00	8.78	17.50
4.29	8.52	16.31
2.57	8.56	14.37
0.86	6.39	11.48

*including power spike factor

All results were acceptable.

4.3 Conclusion

Testing for the 75% power plateau was accomplished in accordance with procedures, data were acceptable, and test objectives were met or proper test exceptions taken.

Facility problems such as OTSG water level were identified through the testing program. The resolution and associated 10 CFR 50.59 review are described in Section 3.2.3.

5. Radioactive Liquid and Gaseous Effluent Control

5.1 Management Controls

The radiological engineering group has primary responsibility for tracking and evaluating radioactive liquid and gaseous effluents. The radiological engineering manager reports through the Manager, Radiological Controls, to the Vice President, Radiological and Environmental Controls. This organization is independent of the plant operations staff that reports to the Vice President and Director, TMI-1. The managers of instrument and controls (I&C) and of chemistry, both of which implement the facility's effluent control programs, also report to the Vice President and Director, TMI-1.

The I&C personnel perform calibrations of process and effluent monitoring instruments. Chemistry personnel perform analyses of the radioactivity content of liquids and gases that are released, as well as analyses of the primary and secondary coolant circulating through the plant systems. The I&C maintenance foreman reports to the Manager, Plant Maintenance, TMI-1. This individual and the chemistry manager both report through the Operations and Maintenance Director TMI-1 to the Vice President and Director, TMI-1.

The licensee's organization as described here conforms to its technical specifications, section 6.2.1, and figures 6-1 and 6-2 in the gaseous and liquid radioactive waste area.

5.2 Audits

Audits of site activities and program areas, including radioactive effluent controls, are performed by the quality assurance audits group, which reports through the Manager, QA Programs/Audits and the Director, QA, to the Vice President, Nuclear Assurance. The Director of Quality Assurance also has direct access to the Office of the President, GPUN. This organization has been kept separate from the plant operations staff in order to promote the independence of audits. The licensee conforms to technical specifications (section 6.2.1 and figure 6-1) in this area.

The inspector reviewed the following audits related to radioactive effluent control:

-- GPUN Audit Report S-TMI-85-02, "Offsite Dose Calculation Manual," conducted January 28-February 2, 1985. The performance of this audit is required at least once per 24 months by Technical Specification 6.5.3.1.h. The audit covered the conformance of the licensee's program for liquid and gaseous effluent control, meteorological monitoring, and offsite dose calculations, to the requirements of 10 CFR Parts 20 and 50, and Regulatory Guides 1.21 and 1.23. The audits also reviewed generic QA program requirements including adequacy of organization, document control, and corrective actions. The inspector found no adverse findings with the implementation of these audits. The audits covered aspects of programs at both TMI-1 and TMI-2.

-- GPUN Audit Report S-TMI-84-19, "Chemistry Program," conducted November 20-December 19, 1984. The performance of this audit is required at least once per 24 months by Technical Specification 6.5.3.1.d and the licensee's Operational Quality Assurance Plan for TMI-1. This audit covered both radiological and non-radiological chemistry, and included reviews of the following areas: organization, training, and qualification;

laboratory quality control; chemicals and supplies; plant water chemistry control; et al. One finding was identified regarding control of TMI-1 chemistry procedures; this was not related to radiochemistry or control of effluents. The chemistry department response was submitted on December 31, 1984, accepted by QA on January 28, 1985, and closed-out on April 8, 1985.

5.3 Effluent Control

The inspector reviewed the licensee's procedures for controlling and quantifying radioactive liquid and gaseous effluents, as required by Technical Specifications, Sections 3.22 and 4.22. Radiological engineering has procedures for tracking releases by means of a system of release permits, and a log of all releases made during each calendar year. Chemistry follows procedures for sampling and analysis of liquids and gases prior to release. The results of these analyses are provided to radiological engineering, which uses them to project the quantities of radionuclides to be released. Radiological engineering also has procedures for compiling actual released quantities and publishing them twice each year in the "Semi-Annual Effluent and Release Report." This report also includes an evaluation of the potential doses received offsite, performed according to methods described in the licensee's offsite dose calculation manual (ODCM). The inspector noted that the licensee has a procedure to implement the methods of the ODCM, and that procedural requirements were being followed.

The inspector reviewed selected release permits and the results of analyses performed for these releases. Of those records selected for review, analyses were performed, all required data were entered on data sheets, and no limits were exceeded. The log of releases was complete, and data entered in the log matched the data from corresponding release permits. This log indicated that all releases in 1985 resulted in concentrations of radioactivity in air and water well below the federal regulatory limits. The inspector also reviewed the licensee's ODCM and its semi-annual effluent and release reports for the last half of 1984 and the first half of 1985. The ODCM provides suitable methods for calculating potential offsite doses due to liquid and gaseous releases. These methods were utilized in preparing the semi-annual reports, which contain compilations of total quantities of radionuclides released, and an evaluation of doses due to these releases. The semi-annual reports contained all required information, and indicated that concentrations of radionuclides released and offsite doses have been below the federal limits of 10 CFR Part 20 and Part 50, Appendix I.

Installed radiation detectors are situated so that planned releases of radioactivity in liquids and gases can be monitored during a release to ensure that the actual concentrations of released material do not exceed (1) planned quantities, (2) technical specification limits, and (3) federal regulatory limits. The licensee's Technical Specification, Sections 4.21.1 and 4.21.2, require that these radiation detectors be calibrated at least once per refueling outage (normally 18 month intervals). The licensee maintains procedures for implementing this requirement; these procedures require quarterly calibration of these monitors, which exceeds the technical specification requirement.

The inspector reviewed selected calibration records for these and other liquid, gaseous, and area radiation monitors, and found that procedural requirements were being met with regard to frequency of calibration. The licensee uses the original isotopic calibration data supplied by the vendor of the radiation monitors, and performs the periodic calibrations with sources that reference the original calibrations.

5.4 Reactor Coolant Water Chemistry

Analyses of dissolved oxygen, fluoride, chloride, boron, specific activity, E-bar, dose-equivalent I-131, and tritium in the primary coolant are required by Technical Specifications, Sections 3.1.4, 3.1.5 and Table 4.1-3. Analyses of the secondary coolant to determine gross activity and iodine (if gross activity increases by a factor of two above background) are also required (T.S. Table 4.1-3). The inspector noted that the requirements for sampling are implemented by surveillance procedures as follows:

Surveillance Procedure No.	Technical Specification (Table 4.1-3) Requirement Implemented
(Primary Coolant)	
1301-3	E-bar, Chloride, Fluoride, Dissolved Oxygen, Boron, Tritium
1301-3E	Specific Activity
1301-3G	Dose Equivalent I-131
(Secondary Coolant)	
1301-4.5	Gross Activity, Iodine Analysis

The inspector reviewed selected records covering these surveillances during 1985, and found no instances in which technical specification limits were not met.

The surveillance for determination of E-bar is required once per six months during power operation, based on a sample taken after a minimum of two effective full power days and twenty days of power operation have elapsed since the reactor was last subcritical for forty-eight hours or longer. The inspector noted that following the restart of TMI-1, the licensee took a sample of reactor coolant pursuant to the technical specification and performed an analysis for the content of gamma-emitting radionuclides. A portion of the sample was sent to the licensee's vendor laboratory for analyses for Sr-89 and Sr-90. The results of these analyses were not yet available at the time of this inspection. The licensee had calculated an interim value for E-bar on November 5, 1985, for use while awaiting the results of the strontium analysis, and began using this interim value on or about November 28, 1985, for comparison to the specific activity of the primary coolant. This comparison is required by Technical Specification Table 4.1-3.1.a. The use of an interim value for E-bar was not covered in the licensee's procedures. The licensee stated that a temporary procedure change would be written to cover the use of this interim value. The addition of the Sr-89 and Sr-90 results to the interim E-bar calibration should have little or no effect on the final value.

5.5 Radioanalytical Quality Control Program

The inspector reviewed the licensee's program for the quality control of radioanalytical measurements, including the following Unit 1 chemistry procedures.

-- N1828, Revision 0, dated August 1, 1985, "Quality Assurance Program for Radiological Effluent Monitoring"

-- N1990.1, Revision 4, dated September 23, 1985, "High Resolution Gamma Ray Spectroscopy Using Canberra Industries Jupiter System"

Procedure N1828 specifies the number and frequency of QC samples to be analyzed both by the licensee's laboratory and by its contractor laboratory. It also provides acceptance criteria and specifies followup action to be taken if the criteria are not met. The intent of this part of the QC program is to ensure that the laboratories are able to accurately analyze samples for radionuclides as required by technical specifications. Procedure N1990.1 includes requirements for the use of quality control charts. On a sampling basis, the inspector reviewed the licensee's quality control charts and selected QC data and concluded that the licensee properly implemented procedural requirements. The inspector also reviewed procedure N1990.2, Revision 1, dated December 4, 1984, "Calibration of the Canberra Industries Jupiter System," and calibration data for the gamma spectroscopy system in both the chemistry and health physics laboratories. This review indicated that both instruments were properly calibrated during March and April 1985, for the various counting geometries used by the licensee for analyses of in-plant and effluent samples.

5.6 Testing of Air Cleaning Systems

The inspector reviewed the licensee's air filtration system testing with respect to the technical specifications requirements. The inspector reviewed the results of the HEPA filter and charcoal absorbed in-place tests conducted in 1985 for the reactor building purge, the emergency control room ventilation, and the auxiliary and fuel handling building exhaust air treatment systems. The tests met the technical specifications requirements. The inspector noted that the licensee has an adequate method for scheduling air filtration system tests, and for logging actual dates on which tests were performed, thus ensuring that the technical specifications requirements for frequency of these tests will be met.

The inspector also reviewed selected records of the monthly operability tests required for the control room and fuel storage building emergency filtration systems. On this sampling basis, the inspector concluded that these tests were performed adequately and on time.

5.7 Conclusion

The licensee is well organized in the control of radioactive effluent. They provide for ample quality control measures for laboratory process and demonstrated continued involvement by the licensee's quality assurance department. The functional area Vice President in charge of this area provides for added measures of independence within GPUN to assure activities affecting quality are properly conducted. No conditions adverse to regulatory requirements were identified.

6. Makeup Pump Operability

The inspector assessed the operability of the makeup pumps based on a review of licensee maintenance (preventive and corrective) and surveillance activities to verify that:

-- procedures required by Technical Specifications (TS) 4.2.2 and 4.5.2.1.b are being properly implemented;

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

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

-- machinery history records and related surveillance and preventive maintenance records were retrievable.

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

-- surveillance procedure (SP) 1300-3H A/B, "Makeup Pump and Valve Functional Test," Revision 16, dated August 30, 1985, including data obtained April 10, 1985, May 26, 1985, June 22, 1985, August 2, 1985, and November 2, 1985;

-- SP 1303-11.8, "High Pressure Injection," Revision 15, dated July 18, 1985, including data obtained on April 11, 1985;

-- PM procedure M-138, "Oil Sampling Procedure," Revision 2, dated March 4, 1985;

-- PM procedure 1410-P-3, "Lube Oil Change," Revision 6, dated February 28, 1985; and,

-- selected job tickets from machinery history files, numbers CF193, CE302, CF904, CE947, CF166, CF191, CF192, CG795, CH016, CG062, and CG063.

Review of the surveillance test results for makeup pump 1A (MU-P-1A) revealed that the delta-P calculations for the test conducted on June 22, 1985 and November 1, 1985 were in the alert range as defined in the ASME Boiler and Pressure Vessel Code, Section XI. The test conducted on June 22, 1985 after extended maintenance and troubleshooting for high pump run currents resulted in the licensee increasing the test frequency to six weeks until new reference values could be established. Subsequent testing on August 2, 1985 determined the delta-P to be in the acceptable range, but during testing on November 1, 1985, the delta-P was again in the alert range. The licensee subsequently established a new reference value based on the August 2, 1985 test results and the manufacturer's original pump performance curve. This higher delta-P value was incorporated into surveillance procedure 1300-3H A/B as revision 17, dated November 25, 1985. During discussions with licensee engineering personnel, it was determined that testing to confirm this new reference value for delta-P would be verified during the next regularly scheduled quarterly surveillance test. The inspector will confirm that the new reference value is acceptable during review or observation of the next surveillance test for MU-P-1A. This item will be reviewed during a subsequent performance of the surveillance test (50-289/85-28-02).

Machinery history provided a useful summary of work activities on the makeup pumps. Referenced job ticket records were retrievable using the licensee's microfiche and microfilm systems. When major corrective maintenance was performed under various job tickets, adequate post-maintenance testing and various independent verifications were specified and performed.

The inspector concluded that the licensee's records were well kept and that these records reflected applicable procedures that were being properly implemented. In-place surveillance and preventive maintenance procedures and post-maintenance testing should provide adequate reliability such that the makeup pumps will be operable when called upon.

7. Cold Weather Preparations

The inspector reviewed maintenance and surveillance aspects of licensee measures to ensure that safety-related equipment remained operable during extreme cold weather conditions. Specifically, the inspector verified that:

-- licensee protective measures, implemented as a result of NRC Bulletin 79-25 for extreme cold weather, continued to be properly implemented; and,

-- the licensee periodically inspects important-to-safety systems susceptible to freezing to verify the operability of heat tracing, space heating, insulation, and other measures such as antifreeze.

The inspector made observations in the auxiliary and intermediate building and at outside areas in the vicinity of the condensate storage tanks and borated water storage tank. Also, the inspector reviewed the following documents:

-- preventive maintenance procedure E-70, "Heat Trace Inspection"

-- operations surveillance (OPS) procedure No. OPS-S85, "OPS Winterization Checks"

-- maintenance procedure 1420-HT-2, "Heat Tracing Troubleshooting and Repair"

-- various job tickets related to corrective maintenance for heat tracing and heater work

The licensee implements a number of positive freeze protection measures to ensure safety-related equipment operability. The annual surveillance, OPS-S85, is an extensive check of: out-building heating/ ventilating systems operation including thermostatic settings, heat trace operability and insulation conditions, and antifreeze for various diesel engine cooling systems or for sprinkler systems. Preventive maintenance procedure E-70 is a functional check of the numerous heat trace circuits and a check of their respective thermostats along with checking insulation and circuit physical conditions. The preventive maintenance and job ticket records indicate no adverse trends.

The licensee properly implemented their freeze protection measures. The annual operations review identified a number of corrective actions to take before the severe cold weather arrived and the licensee completed these actions for the most part. Procedure E-70 records indicated proper implementation of the preventive maintenance procedures. When minor problems with heat tracing are identified, the licensee implements Corrective Maintenance Procedure 1420-HT-2 to troubleshoot the problems. There were several job tickets outstanding for problems identified on the annual surveillance completed during October of 1985.

The inspector concluded that the licensee's overall efforts in freeze protection were adequately implemented and controlled. The inspector had no other concerns in this area.

8. Decay Heat Closed Cooling Water Procedure Review

8.1 Review

The inspector reviewed the following procedures to ascertain whether they are in accordance with regulatory requirements and whether their technical adequacy is consistent with desired actions and modes of operation.

-- OP 1104-13, "Decay Heat Closed Cycle Cooling System," Revision 20, dated October 10, 1985

-- SP 1300-3C, "Decay Heat Closed Cooling Water Pumps Functional Test," Revision 12, dated August 20, 1985

The following documents were used during the scope of this review.

-- GAI Drawing C-302-645, "Decay Heat Closed Cycle Cooling Water," Revision 14

-- "Decay Heat Closed Cycle Cooling Water System," TMI-1 Operations Plant Manual

-- ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants

Also, as part of this review, the inspector toured the decay heat removal and the reactor building spray vaults and performed a valve lineup verification of OP 1104-13.

8.2 Findings

The inspector determined that the step-wise instructions of OP 1104-13 were compatible with checklist information and provisions for signoffs were evident. Appropriate limitations such as temperature limits, cooldown ratios, and throttling requirements were correctly incorporated into the procedure. Various precautions and notes concerning equipment and administrative operability requirements and appropriate technical specification requirements were also incorporated into the procedure. The valve lineup checklist and the piping and instrument diagram were compatible and agreed with each other.

SP 1300-3C met all applicable requirements of Subsection IWP, Section XI of the ASME Code. Technical Specification requirements were evident as well as appropriate limitations and precautions. Signoff provisions were adequate and an independent position verification checklist was attached to the procedure.

The inspector, with the aid of an auxiliary operator, verified the position of valves listed in OP 1104-13. Several valve positions were found to be different from the positions stated in the startup valve checklist. However, these valves were actually in the correct position for the current plant condition at the time of the inspection.

The inspector found the vaults to be clean and neat. Both reactor building spray vaults and the "A" decay heat removal vault had been decontaminated so that protective clothing would not have to be worn to descend into the vaults. The inspector found this to be a great asset to increase the mobility of operations personnel.

8.3 Conclusions

The inspector determined that OP 1104-13 is adequate to control safety-related operations within applicable regulatory requirements. This procedure can be used to safely remove heat from the decay heat removal pumps, motors, and coolers; makeup purification pumps and motors; and reactor building spray pumps and motors. SP 1300-3C provides adequate reliability that the decay heat closed cooling water pumps will be operable when needed.

No adverse conditions were found in the procedures or valve lineup checklist. Visual inspection of the vaults did not identify any problems. The inspector found no conditions that would adversely affect the level of safety in the plant.

9. Licensee Action on Previous Inspection Findings

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

9.1 (Closed) Unresolved Item (289/81-33-04) and TMI Task Action Plan Item (I.G.1): Licensee to provide restart training in preparation for restart and during power escalation testing. Inspection Report 50-289/81-33 identified adequate classroom training for the low power testing sequence but the actual utilization of the facility to demonstrate practical factors was left open pending approval for reactor criticality. This inspection was in response to the NRC staff's safety evaluation report, dated April 22, 1981, for TMI task action plan item (TAP) I.G.1. This TAP item was applicable to near-term operating licenses but it was made applicable to TMI-1 as a prerequisite for restart by the above referenced letter.

The staff's SER noted a tentatively acceptable testing schedule for below 5% power for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training (of which adequate preparations were confirmed in Inspection Report 50-289/81-33). In accordance with the SER, the licensee formally submitted two revisions to the overall restart test planning specifications, which included the low power testing program; the staff found the restart test planning specifications acceptable in a letter dated December 21, 1982, from J. Stolz, NRR, to H. Hukill, GPUN. The focus of the low power test program centered on natural circulation training, validating related operating procedures, and verifying natural circulation characteristics.

This letter, in conjunction with another NRC letter dated September 1, 1983, from J. Stolz, NRR, to H. Hukill, GPUN, provided the staff's review of the licensee's startup test program to provide additional operator training to satisfy the issue of whether to treat TMI-1 differently from other operating reactors because of the prolonged shutdown (Atomic Safety and Licensing Board decision, dated August 27, 1981, paragraph 570 and 571 - Certification Item No. 151). The staff concluded that the licensee had adequate plans to provide operators with the additional requisite training for safety operation.

During NRC inspection 50-289/85-22 the TMI-1 Restart Staff verified proper licensee implementation of the test and training program for low power testing. During this inspection (see paragraph 2.2.3) the staff completed the detailed interviews of selected licensed operators to assess performance aspects related to their knowledge of facility design and integrated operation. NRC conclusions in this area were also based on the numerous observations to date since criticality on operator performance.

The results in paragraph 2.2.3 are favorable. In summary of the PET program to date, a majority of inspectors were impressed with operator preparedness and performance in spite of the long shutdown. It appeared that effective simulator training was provided to the operators and that the training department was a key factor in the positive results along with the competence and overall abilities of the licensed operators.

9.2 (Closed) Unresolved Item (289/84-19-01): Completion of licensee restart qualification cards. Inspection Report 50-289/85-26 verified completion of these qualification cards for the most part but that inspection also identified a lack of usefulness from a qualification viewpoint. The cards were primarily used to record training (simulated) or actual experiences on a shift. The staff does not rely on this card to demonstrate licensed operator abilities and performance factors. That reliance was addressed in paragraph 9.1 above.

9.3 (Closed) Inspector Followup Item (85-04-01) OTSG personnel exposure. The licensee's investigation results from this incident are recorded in a radiological investigative report (RIR). This RIR will be used as part of a historical file on past experiences. Based on this file, future procedures will ensure that air samples, representative of the workers' breathing zones will be collected. The licensee's re-evaluation of past OTSG respiratory protection utilization and MPC-hour assignments, and the licensee's re-assessment of alpha permissible concentration values was found to be satisfactory.

9.4 (Closed) Unresolved Item (289/85-21-01) Static Pressure Alignment of Emergency Feedwater (EFW) Flow Transmitters. This item was originally identified during the restart readiness review by the TMI-1 Restart Staff. At that time, three of the four EFW flow meters indicated approximately 80 gallons per minute (gpm) flow with zero flow in the system. Investigation by the licensee indicated a zero shift of the flow instrument when it was exposed to about 900 pounds per square inch (psi) system pressure through check valve back leakage. The licensee determined the amount of zero shift at pressure (static pressure shift) and calibrated each flow transmitter with the appropriate correction incorporated. This corrected the error and all flow meters then indicated zero flow at zero flow conditions.

Since this type transmitter does not normally experience a static pressure zero shift, the inspector reviewed two of the completed job tickets (CG 721 and CG 720) for flow transmitters EF-FT-0788 and EF-FT-0779 and Foxboro Maintenance Instruction 020-164 to become familiar with the problem, the licensee's resolution, and the flow transmitters.

The flow transmitters sense differential pressure (delta P) via an annubar with 0 to 41.6 inches of water delta P corresponding to a 0 to 800 gpm indication. The flow transmitter output is conditioned via a square root extractor and changed from a 4 to 20 milliamp signal to a 0 to 10 volt direct current signal. The use of an annubar instead of an orifice plate or flow venturi gives a relatively low range of delta P (0-41.6 inches of water in this case) for the 0 to 800 gpm flow desired. This combined with the square root extractor can cause flow readings from very small delta P values. A zero shift when pressure is applied with no delta P applied is caused by a difference in diaphragm area in the flow transmitters. The licensee and the inspector calculated the delta P required to cause an 80 gpm indication. The value was 0.4 inches of water. This amount of delta P at 900 psi correlates to a difference in surface area of approximately 0.0016 percent.

The inspector's review of the completed job tickets and various discussions did not identify any unacceptable licensee action concerning troubleshooting and calibration of the EFW flow transmitters.

9.5 (Closed) Unresolved Item (289/85-26-01) TMI-1 Restart Staff to review licensee's plant incident reports associated with inadvertent loss of TRA bus on November 5, 1985, and small water leak on a flange in the secondary plant moisture separator drain system on November 2, 1985. The inspector reviewed the two plant incident reports (PIR) and discussed each PIR with different plant personnel to ensure that the corrective action described in the licensee's report was in place. The inspector discussed the corrective actions with plant personnel who should be aware of the event and should be knowledgeable about the licensee's corrective action. The corrective actions were reviewed to determine if the licensee's proposed corrective action adequately identified and addressed the root cause.

The inspector concluded that the plant incident reports did address the root cause, and the licensee's corrective action was timely and appeared to resolve the issue. Through discussion with the licensee, the inspector determined that issues were being brought to the attention of plant personnel who needed to know. The inspector reviewed the licensee's conclusions and agreed with their characterization of the problem (i.e., in one case, failure to adhere to applicable procedures and in the other case poor maintenance planning caused the problems).

In addition, the inspector noted that the Vice President of TMI-1 was personally briefing each operating crew on these matters. Two of the six briefings were attended by the inspector. The inspector considered the item resolved.

10. Exit Interview

The inspectors discussed the inspection scope and findings with licensee management at the exit interview conducted on December 13, 1985. The following licensee personnel attended the final exit meeting:

D. W. Atherholt, Operations Engineer
B. E. Ballard, Sr., Manager, TMI QA, Modifications & Operations
R. O. Barley, Manager, Plant Engineering, TMI-1
H. D. Hukill, Vice President and Director, TMI-1
C. L. Incorvati, TMI-1 Audit Supervisor, Nuclear Assurance
G. A. Kuehn, Manager, Radiological Control, TMI-1, Radiological and Environmental Controls
R. E. Neidig, Jr., TMI Communications
M. A. Nelson, Supervisor, TMI-1 Review Program
L. L. Ritter, Administrator II, Plant Operations, TMI-1
D. M. Shovlin, Manager, Plant Maintenance, TMI-1
P. S. Siniga, Administrator, Maintenance, TMI-1
C. W. Smyth, TMI-1 Licensing Manager, Technical Functions
R. J. Toole, Operations and Maintenance Director, TMI-1
S. E. Williams, Radiological Engineering, TMI-1

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