U.S. NUCLEAR REGULATORY COMMISSION 50289-800715

Region I

Report No. 50-289/83-01

Docket No. 50-289

License No. DPR-50 Priority -- Category C

Licensee: GPU Nuclear Corporation

P.O. Box 480

Middletown, Pennsylvania 17057

Facility: Three Mile Island Nuclear Station, Unit 1

Inspection at: Middletown, Pennsylvania

Inspection conducted: January 4-31, 1983

Inspectors:	R Conte	2/4/83
	R. Conte, Senior Resident Inspector (TMI-1)	date signed
	D R Haverkamp	2/9/83
	D. Haverkamp, Reactor Licensing Engineer	date signed
	R Conte for	2/4/83
	L. Thonus, Resident Inspector (TMI-2)	date signed
	F Young	Feb 9, 1983
	F. Young, Resident Inspector (TMI-1)	date signed
Approved by:	R. Keimig	2-9-83
	R. Keimig, Acting Chief, Reactor Projects Section No. 2C, Projects Branch No. 2, DPRP	date signed

Inspection Summary:

Inspection conducted on January 4-31, 1983, (Inspection Report Number 50-289/83-01)

Areas Inspected: Routine safety inspection by resident inspectors of licensee action on previous inspection findings; plant operations including steam generator repairs; reactor coolant system pressure control testing; liquid radwaste system separation; and restart modifications. The inspection involved 177 inspector-hours.

Results: No violations were identified.

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Details

1. Persons Contacted

General Public Utilities (GPU) Nuclear Corporation

R. Sarley, Lead Mechanical Engineer TMI-1
J. Colitz, Plant Engineering Director TMI-1
T. Hawkins, Manager TMI-1, Startup and Test, Technical Functions
R. Harper, Corrective Maintenance Manager TMI-1
*C. Kimball, Quality Assurance (QA) Monitor, Nuclear Assurance
J. Kuehn, Manager, Radiological Controls TMI-1
S. Levin, Maintenance and Construction Director TMI-1
F. Paulewicz, Mechanical Engineer TMI-1
S. Pruitt, TMI-1 ISI (Inservice Inspection) Supervisor
H. Shipman, Engineer III, TMI-1
*C. Smyth, Supervisor TMI-1 Licensing, Technical Functions
R. Szczech, Nuclear Licensing Engineer, Technical Functions
R. Toole, Operations and Maintenance Director TMI-1

Other personnel in the operations, engineering, and quality assurance staffs were also interviewed.

*denotes those present at an exit interview.

2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (289/78-07-05): Applicability of 10 CFR 50, Appendix J, Type C testing to decay heat removal system valves. License Amendment No. 63, dated March 30, 1981, contains the NRC's safety evaluation which concludes containment integrity type C testing is not required for DH-V2 and V3, Decay Heat Suction Valves from Loop B, and therefore the licensee's associated exemption request was not needed.

(Closed) Inspector Follow Item (289/80-30-03): Licensee to submit a final report on a reportable occurrence. Licensee Event Report (LER) No. 80-013/03L-0, dated August 18, 1980, Pressurizer Code Safety Valve Setpoint not within Technical Specification (TS) limits on July 15, 1980, indicated that an investigation and evaluation with results would be provided in a subsequent report targeted for November 1, 1980. Although licensee action was not completed until July 1981, with a final report dated September 25, 1981, the licensee met the intent of their commitment by providing interim status reports dated November 17, 1980, and March 13, 1981. The timeliness of these reports were appropriate to the level of work activity associated with this and other restart issues. The in-plant review of LER 80-013 is addressed below.

(Closed) Licensee Event Report (289/80-LO-13): In plant review of LER No. 80-13/03L-2, pressurizer code safety valve setpoint error. During the performance of surveillance testing of pressurizer code safety, RC-V1B, on July 15, 1980, the licensee determined that the actual lift setpoint was 2330 psig, which was not within Technical Specification limits (2500 $\pm$ 1% psig). Subsequent reporting on this event was addressed above (289/80-30-03). The licensee's investigation was inconclusive but did identify (1) that their review was hampered in that performance of previous surveillance testing did not document all intermediate and final valve adjustments to detect trends, and (2) that the site heated nitrogen test methodology may not be valid. Surveillance Procedure 1303-11.2, Pressurizer Code Safety Valve Setpoint Verification, was revised to record the amount and direction of any adjustments made to the valve compression screws between successive openings ("pops") as noted in Revision 7, dated December 2, 1981. Service specification (GPU) 1101-12-020, Revision 1, dated February 27, 1981, Pressurizer Code Safety Testing, also incorporates this requirement in paragraph 4.7.1. This specification was used in the procurement documents for services provided by Wyle Laboratories as noted below.

The licensee further took the initiative to contract services from Wyle Laboratories to perform additional relief valve testing on both spare code safeties using hot water (450°F), hot nitrogen (250°F) and steam (650°F). The test data produced between May and July 1981 as documented in Wyle Laboratories Test Report No. 45597-0, dated July 1981, was reviewed by the inspector. The report identified that the setpoint values varied with test fluid used, even with valve body temperatures consistently controlled. The report was inconclusive as to why setpoint varied with test fluid used. Subsequently, in a letter dated September 25, 1981, the licensee committed to perform the setpoint verification on pressurizer code safeties using steam.

Job Ticket (JT) C5903, dated May 1, 1981, (field completion date July 22, 1981) was also reviewed to verify that the spare code safeties were refurbished, tested using steam and installed in the plant to support hot functional testing in August 1981. The inspector noted that SP 1303-11.2 (referenced in JT C5903) still permitted the heated nitrogen test methodology. However, Procedure Change Request 82-8600 was already initiated and being reviewed by the licensee to delete this method as an acceptable code safety setpoint test. The inspector had no further comments in this area.

(Closed) Inspector Follow Item (289/82-BC-16): Separation of TMI-1/TMI-2 liquid radwaste systems. Details are in paragraph 4.

(Closed) Inspector Follow Item (289/82-BC-21): Expand solid waste storage. This item was previously examined in Inspection Report 50-289/82-21. Applicable documentation was reviewed to verify that the licensee had completed acceptance and turnover of the interim solid waste storage facility (ISWSF).

(Open) Inspector Follow Item (289/82-BC-41): Installation of emergency feedwater sonic flow devices. Details are in paragraph 6.a.

(Closed) Inspector Follow Item (289/83-BC-10): Disconnect feedwater latch signal from emergency feedwater system. Details are in paragraph 6.b.

(Closed) Inspector Follow Item (289/83-BC-16): Installation of emergency feedwater cavitating venturies. Details are in paragraph 6.c.

(Closed) Unresolved Item (289/82-13-01): Review and revise EP 1202-6b, EP 1202-6C and OP 1104-4 with respect to post-accident access to vital area equipment. NRC Region I Inspection Report 50-289/82-13, paragraph 4.e(2) described several procedural changes that were needed regarding post-accident access to vital area equipment. During this inspection, the inspector reviewed the following licensee approved Procedure Change Request (PCR) and revised procedures:

-- PCR No. 1-OS-82-0675, approved January 26, 1983 [for Three Mile Island Nuclear Station Unit No. 1 (TMI-1) Operating Procedure 1104-4. Decay Heat Removal System, Revision 34]

-- TMI-1 Emergency Procedure 1202-6B, Loss of Reactor Coolant/Reactor Coolant Pressure (Small Break LOCA) Causing Automatic High Pressure Injection, Revision 15, dated December 7, 1982

-- TMI-1 Emergency Procedure 1202-6C, Loss of Reactor Coolant/Reactor Coolant Pressure Causing Automatic High Pressure Injection, Core Flood and Low Pressure Injection, Revision 12, dated January 5, 1983

-- TMI-1 Emergency Procedure 1202-39, Inadequate Core Cooling (No LOCA), Revision 10, dated December 7, 1982

-- TMI-1 Alarm Response Procedure E-1-8 (ALARM: Borated Water Storage Tank Level Lo-Lo), Revision 1, undated

The inspector verified that the above PCR and revised procedures included changes with respect to the following matters:

-- The long term recirculation modes are consistent with the modes considered acceptable by the NRC staff.

-- Pending completion of remote-operated valves, the procedures have been revised to inform operators of potential post-accident high radiation conditions and to reduce dose rates as low as reasonably achievable.

-- MU-V-198 is required to be manually opened before going into the Reactor Building (RB) sump recirculation modes.

-- DH-V-15A&B are no longer required to be operated.

-- DH-V-64 is required to be manually operated prior to establishing RB sump recirculation.

The inspector determined that the procedural changes provided appropriate resolution of the previous concerns in this area.

(Closed) Inspector Follow Item (289/82-13-02): Determine corrective actions to allow operation of DC-V-2A/B and DC-V-65A/B. The licensee has determined that short term and long term actions are needed to control post-accident continued decay heat removal. The short term action included the addition of a note to TMI-1 Emergency Procedures 1202-6B, Revision 15 and 1202-6C, Revision 12. The note stated that any required control of RCS cooling, if the controls for DC-V-2A/B and DC-V-65A/B are inaccessible, can be accomplished by either throttling DR-V-1A/B or stopping/starting DR-P-1A/B as necessary. The long term action includes relocation of the existing controls for DC-V-2A/B and DC-V-65A/B to an accessible area, as described in the licensee's Division I System Design Description 212G, Revision 3. This modification is currently scheduled for completion during the first refueling outage following restart. (See discussion for Inspector Follow Item 289/82-13-03.) The inspector determined that the procedure changes provide adequate short term resolution of this matter and stated that the relocation of valve controls will be verified during subsequent NRC review of actions per the below item (289/82-13-03).

(Open) Inspector Follow Item (289/82-13-03): Review modifications for valves DH-V-19A/B, DH-V-38A/B, and DH-V-12A/B. As discussed in NRC Region I Inspection Report 50-289/82-13, paragraphs 4.d(3) and 4.d(4), the licensee was seeking NRC approval for deferring modifications for DH-V-19A/B, DH-V-38A/B, and DH-V-12A/B until Cycle 6 refueling. The NRC staff has reviewed the licensee's justification for deferral of these modifications and has recommended that the Commission approve for TMI-1 the deferral of the NUREG-0737, Item II.B.2.2 proposed implementation date to the first refueling outage following restart (Reference: SECY-82-384A, dated December 6, 1982). The Commission subsequently approved the staff's recommendations, as discussed in an NRC letter to the licensee, dated January 12, 1983.

In conjunction with the above valve modifications, the licensee is also planning modifications to provide a reach rod extension for valve DH-V-64 and to relocate the existing controls for valves DC-V-2A/B and DC-V-65A/B (see discussion for item 289/83-13-02). These modifications are described in Division I System Design Description 212G, Revision 3, approved November 26, 1980. During this inspection, the inspector determined that engineering design and material procurement activities for these modifications were still in progress, to support the maintenance and construction activities planned for the Cycle 6 refueling outage. The final installation of these modifications will be reviewed during a subsequent NRC Region I inspection.

3. Plant Operations During Long Term Shutdown

a. Plant Operations Review

Inspections of the facility were conducted to assess implementation of general operating requirements of Section 6 of Technical Specifications in the following areas: licensee review of selected plant parameters for abnormal trends; plant status from a maintenance/modification viewpoint including plant cleanliness; control of documents including log keeping practices; licensee implementation of the security plan including access controls/boundary integrity and badging practices; licensee control of ongoing and special evolutions including control room personnel awareness of these evolutions; and implementation of radiological controls.

Random inspections of the control room during regular and back shift hours were conducted. The selected sections of the shift foreman's log and control room operator's log were reviewed for the period January 4, 1983, to January 31, 1983. Selected sections of other control room daily logs were reviewed for the period from midnight to the time of review. Inspections of areas outside the control room occurred on January 4, 6, 11, 12, 13, 17, 19 and 21, 1983. Selected licensee planning meetings were also observed. Maintenance and surveillance records were reviewed to support the verification of licensee action on previous inspection findings.

Results of this review indicated that the licensee continued to exhibit proper managerial control of daily activities. Housekeeping was, in general, adequate for the level of maintenance/modification work conducted. Control room operators continued to perform in a professional manner. Records were properly completed as sufficient evidence of activities performed.

b. Steam Generator Tube Leak Repairs

The repair process continued in both "A" and "B" Once Through Steam Generators (OTSG) with completion of the kinetic expansion repair portion during this inspection period (ref. NRC Inspection Report 50-289/82-28). Candle debris removal was started. Debris removal is expected to be completed by February 7, 1983. After completion of debris removal, tube end milling will be performed on all tube ends in the upper OTSG heads to prevent the formation of loose pieces during power operations (if permitted). Tube end milling is expected to take two to three weeks to complete. In addition to ending milling, tube stabilization, final cleanup, and selected testing will be performed. Projected completion of all OTSG repair work to OTSG is April 1983.

Due to the significance and severity of the OTSG tube degradation, the inspector frequently observed various aspects of the repair process. On several occasions the inspector observed the kinetic expansion process and candle debris removal being performed in the OTSGs. A selected review of records, completed at the job site, was conducted. The adequacy of the procedures used at the time of observation was also reviewed. In addition, discussions were conducted with several craftsmen and supervisors on different shifts to assess the knowledge level and understanding by key individuals.

Results of this review are similar to that described in paragraph 3.a, above.

4. Separation of TMI-1 and TMI-2 Liquid Radwaste Systems

The licensee's commitments regarding separation of radwaste systems between TMI-1 and TMI-2 are referenced in NRC Inspection Report No. 50-289/82-21. Licensee completion of all commitments, except TMI-2 components, was described in that report.

The surveillance procedure and operating procedure used to assure isolation of TMI-2 components were reviewed. The procedures were adequate and had been implemented by the licensee. The inspector field checked the TMI-2 isolation methods for the following components.

Component	Isolation Methodology
Valve ALC-V169	locked shut
Valve WDL-V274	locked shut
Valve WDS-V15	control air removed, shut
Valve WDS-V59	control air removed, shut
Valve WDL-V1172	control air removed, shut
Valve WDL-1175	locked shut

Proper valve positions/conditions were noted.

5. Reactor Coolant System Pressure Control Testing

a. Pressurizer Heaters

In its Partial Initial Decision (PID) of December 14, 1981, on Plant Design and Procedures and Separation Issues, the TMI-1 Restart Atomic Safety and Licensing Board (ASLB) at paragraph 755 recognized the importance of being able to control Reactor Coolant System (RCS) pressure during natural circulation and feed and bleed cooling modes for reactor core decay heat removal. The Board recommended (immediate effectiveness pending Commission decision) that the licensee demonstrate RCS pressure control using the High Pressure Injection (HPI) System with the following limited test conditions specified:

(1) Simulated or actual loss of offsite power;

(2) RCS average coolant temperature close to normal operating temperature;

(3) Normal letdown system may be used to avoid unnecessary wear and tear on the safety valves; and,

(4) That the test be performed before restart to the satisfaction of the staff (NRC).

The licensee's letter, dated December 7, 1982, (No. 5211-82-272, Hukill to Stolz/Haynes), stated that a test in the fall of 1981 (prior to the issuance of the subject PID) was responsive to the Board's "requirements" and indicated that the test records were on site available for review. The licensee concluded that appropriate testing was performed and requested concurrence by the NRC staff. Accordingly, an onsite review of the below listed documents was conducted to certify this item.

(1) Test Procedure (TP) 664/5, Revision 0, dated August 24, 1981, Pressurizer Operation Test (Task RM-16) - Test Results Evaluation, completed October 13, 1981;

(2) TP 427/2, Revision 0, dated December 18, 1981, Pressurizer Heater Emergency Power Functional Test (Task RM-16) - Test Results Evaluation, completed July 22, 1982; and,

(3) TP 700/2, Revision 0, dated March 18, 1982, Low Power Natural Circulation Test.

Applicable sections of TP 664/5 test data were recorded on September 3-4, 1981, and applicable sections of TP 427/2 test data were recorded on April 29-30, 1982.

The first test condition, simulation of loss of offsite power, was met by keeping pressurizer heaters deenergized for two hours and a block valve closed preventing pressurizer spray. Reactor coolant pumps (RCPs) and Turbine Bypass System were used to maintain a constant RCS average temperature (Tave) simulating a heat source and sink along with constant RCS flow.

The second condition, near normal operating temperature, was met by maintaining a constant Tave at approximately 532°F as noted above. On this condition, the Board was not clear as to what they defined normal operating average temperature to be. From 0% to 15% reactor power, Tave is programmed from approximately 532°F to 579°F and from 15% to 100% reactor power Tave is maintained at 579°F. On a loss of offsite power and following the resultant reactor trip, steam dumps would control steam pressure at 1030 psig (saturation temperature of approximately 547°F) without operator action. The cold leg temperature would approach this saturation temperature. Considering a 30°-50°F differential temperature (hot leg versus cold leg) anticipated for natural circulation and pressurizer temperature at the end of the two hour test (630.4°F), the hot legs should remain subcooled within a two hour period. For the purpose of meeting this condition, the test results at 532°F are acceptable.

The third test condition, which permitted the use of the letdown system was met. Pressurizer level control was in automatic maintaining level at 220-222", with recorded data indicating makeup flow at approximately 29-30 gpm. A qualitative analysis of the data indicated that makeup flow responded to the level shrink in the pressurizer due to ambient heat losses without the use of pressurizer heaters. Pressurizer temperature decreased from 643°F (2164 psig, RCS pressure) to 630.4°F (1945 psig, RCS pressure) during the two hour test.

The fourth condition was met in that the test was performed before restart and was evaluated during this inspection period.

The following inspection findings should be noted. Pressure control in the plant during the test were governed primarily by the saturation conditions in the pressurizer. The makeup system (makeup pumps are the HPI pumps) and letdown system were used to maintain RCS water inventory. The inspector reviewed the makeup pump performance curves and noted that there would be sufficient head capacity for the makeup pumps to fill the pressurizer to a "solid" (no steam bubble) condition and raise pressure to the code safety setpoint (2500 $\pm$ 1% psig), if desired. Licensee representatives indicated that a solid plant test was not planned and was not warranted since they shared the Board's concern on unnecessary wear and tear on the safety valves. Further sufficient information exists to demonstrate the ability of the Makeup Pumps to raise pressure to the safety valve set point, if desired.

Based on the inspector's understanding of the Board's recommendations, the licensee has fulfilled the intent of the RCS pressure control testing and the inspector has no further questions at this time. Additional testing is planned as noted below.

(b) <u>Connection of Pressurizer Heaters to Diesels</u>

In a related matter to the above, the Board required (pending Commission decision on immediate effectiveness), in paragraph 772 of the subject PID, that the licensee demonstrate, in a test, the connection and energization of pressurizer heaters from the emergency busses. Limited test conditions specified by the board were:

(1) To be conducted under conditions that could be reasonably expected at the time such connection would be desirable;

(2) Monitored by the staff (NRC); and,

(3) Results evaluated by the staff.

Test Procedure 664/2 demonstrated that the energization of Group 8 or 9 pressurizer heaters (126 KW each) provides sufficient energy to turn the pressure decrease at the end of the two hour test referenced above. Since the modification to supply emergency bus power to these heaters was not completed in September 1981, normal power was used. In April 1982, it (TP 427/2) was demonstrated that Group 8 or 9 heaters could be transferred to the emergency busses within 26 minutes and 17 minutes, respectively; but it was not monitored by NRC.

A test (TP 700/2) integrating heater power supply transfer, energization and pressure control is planned for the Low Power Physics Testing in May 1982. This test procedure was primarily developed to demonstrate natural circulation with reactor power at approximately 3% to simulate post trip decay heat, no RCPs, Tave at 541 ± 2°F, and RCS heat removal using the turbine bypass system. However, the transfer of Group 8 and 9 pressurizer heaters to emergency power will also be conducted. At that time, the NRC staff will be notified and will monitc the test and evaluate the test results.

The inspector concluded that the subject ASLB requirements have not yet been met and will be certified in a subsequent inspection. This area is unresolved pending completion of licensee action and subsequent NRC review (289/83-01-01).

6. Restart Modification

a. Task RM-13B, Emergency Feedwater Flow Measurement

A review of Task RM-13B was conducted to verify that the new designs provided are consistent and meet the requirements delineated in NUREG 0680 (and supplements), Section 8-2.1.7, and Atomic Safety and Licensing Board (ASLB) Partial Initial Decision (PID), dated December 4, 1981, paragraph 1029. The purpose of Task RM-13B is to install safety grade flow indication of emergency feedwater (EFW) in the control room for both EFW headers. EFW flow indication consists of four instrument channels (2 per header). Each channel consists of a pair of clamp-on transducers, a flow display computer and a remote display unit mounted in the control room. The two channels associated with each EFW header receive power from different independent redundant onsite power sources.

The inspector reviewed, on a sampling basis, the documentation associated with the implementation of the modification including as built drawings, test packages, purchase orders, quality control inspection reports, field change requests and the documentation for Engineering Change Memorandum (ECM) 006, and revisions thereto. A walkdown of the installation of selected components was also conducted.

Implementation of the modification package was adequate except as noted below. The inspector questioned the seismic and environmental qualification of the equipment supplied by the vendor. Licensee representatives were unable to provide proper documentation to substantiate seismic and environmental qualification for all the subject components such as the control room display unit. Licensee representatives committed to at least obtain the appropriate data from the vendor, and perform an evaluation to assure the equipment meets the applicable specifications prior to restart.

This area is unresolved pending completion of licensee action and subsequent NRC review (289/82-BC-41).

b. Task RM-13B, Disconnect FW Latch Signal Circuits

Verification of work performed by Task RM-13B was conducted to ensure that scope of work met the requirements delineated in NUREG 0680 (and supplements), Section 8-2.1.7 and ASLB PID, II.Q, dated December 4, 1981, paragraph 1064. The purpose of Task RM-13B was also to delete the mainsteam line rupture detection signal (SLRDS), which on low OTSG pressure isolated all feedwater to the effected OTSG. The need for this function was precluded with the installation of cavitating venturies. By lifting certain SLRDS leads, emergency feedwater to the OTSG will not be isolated. Flow will be limited by cavitating venturies.

The inspector reviewed, on a sampling basis, the documentation associated with the implementation of the modification including as-built drawings, test package, work authorization packages and the documentation in the turnover package for ECM 303, and changes thereto. In addition, the inspector visually inspected several terminal boxes to verify that proper circuitry leads had been lifted as stated in the applicable work package.

Based on the above, the inspector considered the work defined in this task adequate except for testing. Testing of the work will be done under Test Procedure (TP) 250/1, which will be performed after the OTSGs are returned to service. This TP is being followed and will be reviewed during a subsequent NRC inspection in the preoperational test area.

c. Task LM-13A/B, Installation of Emergency Feedwater Cavitating Venturies

Review of Task LM-13A/B was performed to verify that the new designs provided are consistent and meet the requirements delineated in NUREG 0680 (and supplements), Section 8-2.1.7 and ASLB PID, dated December 4, 1981, paragraph 1037. The purpose of Task LM-13A/B is to install cavitating venturies in each emergency feedwater line to limit the maximum flow achievable to a steam generator. This reduced flow will allow additional time for the operator to diagnose a potential overfill situation. In addition, the venturies will limit the amount of emergency feedwater flows during main steam line break to the effected OTSG.

The inspector reviewed, on a sampling basis, the documentation associated with the implementation of the modification including as-built drawings, test packages, weld history, quality control inspection reports, field change requests and the documentation turnover package for ECM No. 280, and changes thereto. In addition, the inspector visually inspected the installed venturies and verified the component location was as described in the applicable modification documentation.

The inspector considered the implementation of this modification to be adequate except for one significant incomplete work (IWL). This IWL was to conduct preoperational test procedure TP 233/3, which is being followed and will be reviewed in a subsequent inspection in the preoperational test area.

7. Inspector Follow Items

Inspector follow items identified in this report (paragraph 2) are matters that required NRC verification of licensee completion as a result of the TMI-1 Restart Hearings.

8. Unresolved Items

Unresolved items (paragraph 2 and 6.a) are matters about which more information is required in order to ascertain if they are acceptable, violations, or deviations.

9. Exit Interview

The inspectors met with the licensee representatives (denoted in paragraph 1) and at the conclusion of the inspection on January 31, 1983, to discuss the inspection scope and findings.