U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 85-16
85-04

Docket No. 50-352
50-353

License No. NPF-27
CPPR-107

Priority -

Category C
A

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1 & 2

Inspection Conducted: March 16 - April 30, 1985

Inspectors: J. T. Wiggins
Senior Resident Inspector

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Reviewed by: J E Beall 5/31/85
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Reactor Projects Section 2A
Date

Approved by: Robert M. Gallo 5/31/85
R. M. Gallo, Chief
Reactor Projects Section 2A
Date

Inspection Summary: Combined Inspection Report for Inspection Conducted March 16 - April 30, 1985(Report Nos. 50-352/85-16, 50-353/85-04)

Areas Inspected: Routine and backshift inspections by the resident inspector and region-based inspectors of: followup on outstanding inspection items; plant tour; review of licensee compliance to selected license conditions; preoperational

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test exception review and closeout; review of events which occurred during this reporting period; fire protection program implementation; licensee's response to selected safety issues; initial main turbine roll activities; review of special and routine reports; monthly surveillance observations; and maintenance observations.

Result: One violation was identified. The inspector also noted that the licensee's corrective action regarding personnel-error related events appears to have been effective.

DCS Nos.: 50-352 85-0322
85-0326
85-0330
85-0410
85-0112
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85-0208
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85-0205
85-0131

DETAILS

1. Persons Contacted

Philadelphia Electric Company (PECo)

J. Corcoran, Field QA Branch Head
J. Cotton, Maintenance Engineer
J. Doering, Operations Engineer
P. Duca, Technical Engineer
J. Franz, Assistant Station Superintendent
R. Kankus, Director, Emergency Preparedness
G. Leitch, Station Superintendent
J. Rubert, Site Quality Assurance Supervisor

Also, during this inspection period, the inspectors discussed plant status and operations with other supervisors and engineers in the PECo, Bechtel and General Electric organizations.

2. Followup on Outstanding Inspection Items

2.1 Violations and Deviations

2.1.1 (Closed) Violation 50-352/84-53-01: Separation criteria for cabling entering the bottom of control room panel 10C601 was not met.

The inspector reviewed the licensee's response to the violation dated 2/26/85 and also reviewed quality records which addressed the corrective actions taken. These records included nonconformance reports (NCR) 10403 and 10405 along with Quality Control field inspection records for the corrective actions taken to dispose of the NCRs. The licensee's actions included the inspection of the room panels for similar separation discrepancies and an inspection of cables which penetrate the blockouts in the ceiling of the cable spreading room and in the floor of the auxiliary equipment room. No additional separation problems were identified in the control room or in the auxiliary equipment room, however, several were identified and corrected in the cable spreading room. Independently, adequate physical separation of cabling into panel 10C601 was observed by the Senior Resident Inspector for Construction prior to issuance of the facility low power license in October, 1984.

2.1.2 (Closed) Violation 50-352/84-53-02: Cable entry ports into main control room panel 10C601 were not sealed to prevent accumulation of dust and debris as required by drawing E-1406.

The inspector reviewed the licensee's 2/26/85 response to this violation along with the associated Quality Control Inspection Records (QCIR) which documented completion of the corrective actions. These actions involved installation of dust covers and an inspection of all Q-listed panels in the plant, including those in the reactor enclosure, the control enclosure, the diesel generator enclosure and the spray pond pumphouse. No other problems were identified. In addition, the inspector reviewed revisions to sheets 4.6.6, 5.2.1 and 5.2.2 of E-1406 which provided the design details for panel sealing which would be used during construction of Unit 2 and modifications to Unit 1. The dust cover installation at panel 10C601 was independently observed to be adequate by the Senior Resident Inspector for Construction prior to issuance of the facility low power license in October, 1984.

2.1.3 (Closed) Violation 50-352/84-53-03: Inadequately controlled installation of temporary communications cables in Q-listed panels.

The inspector reviewed the licensee's 2/26/85 response to this violation which indicated that the temporary cabling identified at the time of the inspection had been removed. This was verified by the Senior Resident Inspector for Construction prior to issuance of the facility low power license in October, 1984. Additionally, the individuals in the Startup organization were retrained in the requirements for temporary modification control. Further,the licensee committed to perform a reinspection of all temporary cabling installed during the Startup Test phase by June 1, 1985.

2.1.4 (Closed) Violation 84-64-01; UNR 84-64-0?: Personnel and Material Accountability in areas requiring housekeeping controls: The licensee revised A-30, "Administrative Procedure for Good Housekeeping", to now include both a material and personnel accountability log as Appendices. The inspector reviewed the logs and pertinent sections of A-30, and determined that the procedure contains sufficient guidance for accountability purposes. The inspector reviewed the training records, i.e., the lesson plans and attendance sheets, for training on A-30 given to licensed and non-licensed personnel. The inspector, during a plant tour, also noted that plaques have been placed on the refueling bridge which instruct individuals on personnel and material accountability. The inspector had no further questions.

2.1.5 (Closed) Violation 50-352/84-65-06: Failure to follow administrative procedures when the reactor protection system power supply breakers were returned to service after maintenance.

The inspector reviewed the licensee's response to this violation in its letter dated 2/11/85. In this letter, the licensee indicated that its corrective action involved an administrative correction to the system for filling out maintenance request operational verification forms. The inspector informed the licensee that this corrective action was not fully responsive to his concerns. The inspector reiterated his concern that the breakers were returned to service and control rod testing had recommenced while the maintenance action was still open; i.e., section 6 of the maintenance request form (MRF) was not completed indicating the operational verification review had not been conducted. In response, the licensee informed the inspector of the following additional corrective actions which had been taken. The MRF for the job was corrected to reflect the exact extent of post-work testing which had been performed and the completed test records were attached to the MRF. Further administrative procedures A-26 and A-41 covering corrective maintenance and control of safety-related equipment had been appropriately revised to clarify the need for completion of an operational verification review before equipment is returned to service. Additionally, the inspector was provided information regarding operations department training on the above procedure changes.

The inspector had no further questions.

2.1.6 (Closed) Violation 50-352/85-01-01: Failure to follow the procedures for preoperational testing and quality control (QC) inspection of the circuits shown on drawing E-519.

In its 2/21/85 letter, the licensee stated the corrective actions for this violation which included the restoration of the affected valve control logic circuit to its required condition and investigations of other PECo Field Engineering Rework Notices and of the documentation regarding the testing for all other primary and secondary containment isolation valves. No other discrepancies were identified. Further, the PECo field engineers and the QC inspectors were retrained regarding the requirements for using up-to-date drawings during the performance of their activities.

2.1.7 (Closed) Deviation 50-352/85-01-02: Failure to follow the FSAR test method description for testing the Containment Isolation and Nuclear Steam Supply Shutoff System.

The inspector reviewed the licensee's response dated 2/21/85 which indicated that a review of test results documentation for all containment isolation valves other than SV-026-190A, B,C, D (subject of Violation 50-352/85-01-01), indicated that no other instances existed wherein the FSAR test method description was not implemented through either the preoperational test procedure itself or through "Blue Tag" testing records. The inspector had no further questions.

2.1.8 (Closed) Violation 50-352/85-02-02: Removal of Technical Specifications - related equipment from service without prior authorization.

The inspector reviewed the licensee's response to this violation contained in its letter dated 3/29/85. Corrective actions included issuance of a memorandum to the Operations, Maintenance and Technical departments regarding when equipment undergoing maintenance should be declared inoperable and the implementation of a procedure which requires control room operators to verify technical specification compliance based on a daily review of control room indications of system status and plant parameters.

The inspector reviewed the memorandum discussed above from the Operations Engineer to the operating shifts and reviewed procedure RT-6-111-985-1 and determined to be satisfactory. The inspector had no further questions.

2.1.9 (Closed) Violation 50-352/85-02-03: Improper operation of the control room heating, ventilating and air conditioning system.

The licensee response to this violation was contained in a 3/29/85 letter. The inspector reviewed this letter along with a memorandum to the shift, dated 2/20/85, which directed that, in response to indications of low differential pressure between the control room and the turbine building, a control room radiation isolation is to be initiated. Further, the inspector reviewed draft blocking sequences 78-1028 and 78-1029 which required a shutdown of the control room toilet exhaust fan and closure of the isolation valves whenever work is to be performed which could result in a loss of positive control room pressure control. In the interim until the blocking sequences are formally issued, the shift was informed by memorandum dated 4/17/85 to include the toilet exhaust fan and valves on permits written to cover work. The inspector further noted that a modification is planned to add a control room alarm on low differential pressure. The inspector had no further questions.

2.1.10 (Closed) Violation 50-352/85-08-01: Failure to maintain two reactor water cleanup system containment isolation valves operable.

The inspector reviewed the licensee's 3/1/85 response to the violation. In the response, the licensee stated that corrective actions included the counselling of the individuals involved and a modification implemented to allow the Riley temperature monitoring switches to be operated without causing the spurious closure of the associated containment isolation valves. Further, temporary changes were made to the daily surveillance log and a memorandum was issued to the operating shifts to prevent recurrence. Additional corrective actions included the scheduling of 24 hours of Technical Specification training for reactor operators, senior operators, shift technical advisors and shift advisors, improvements to control room log review requirements and the institution of an operational excellence program. The inspector verified that each of the licensee's corrective actions had been implemented.

2.2 Unresolved and Follow Items

2.2.1 (Closed) Unresolved Item 50-352/84-18-01: The licensee has formally assigned an onsite Emergency Preparedness Coordinator (EPC) who has the appropriate experience and qualifications specified by Position Guide for this position dated November 1984. The Site Emergency Plan indicates that the EPC reports to the Site Emergency Coordinator upon activation of the Plan. The inspector had no further questions in this area.

2.2.2 (Closed) Unresolved Item 50-352/84-18-02: The licensee has developed a schedule of actions to implement and coordinate the various tasks required by the Emergency Preparedness Program. The schedule clearly identifies the required tasks, responsibilities,and time frames for accomplishing the tasks. The schedule when integrated with the training schedule/matrix provides a detailed management tool for implementing the program on a continuing basis. Based on these findings, the item is closed.

2.2.3 (Closed) Unresolved Item 50-352/84-18-03: Emergency Organization Functions and Responsibilities during Emergency Phases. The inspector reviewed Section 5, Rev. 13, 3/85 of the Limerick Generating Station Emergency Plan to determine if the functions and responsibilities of specific emergency response organization members during all emergency phases had been addressed. The inspector found the discussions of responsibilities, transfer of responsibilities, information flow and response coordination to be appropriate and comprehensive. The fulfillment of emergency response functions and responsibilities during each emergency phase has also been appropriately addressed. Based on these findings, this item is closed.

2.2.4 (Closed) Unresolved Item 50-352/84-18-07: Emergency Response Function Qualification Criteria. The inspector reviewed 6 of the 74 position guides for the members of the LGS Emergency Response organization for qualification requirements. The inspector noted that each position guide contained a general statement that LGS Emergency Response Training Requirements should be successfully completed. Further investigation revealed that there are specific training requirements for each position depending on the functions performed during an emergency (LGS Emergency Plan, Section 8.1.1 Training, Rev. 13, 3/85). The inspector then reviewed the training matrix and training records for several specific emergency response positions. The training indicated for these positions provided adequate instruction for the emergency response function and for sharpening the skills required to perform that function. Based on these findings, this item is closed.

2.2.5 (Closed) Unresolved Item 50-352/84-18-45: A consultant has performed an analysis of the acoustic data from testing of the prompt notification sirens within the ten mile radius of the station. A preliminary evaluation of the data was documented in a letter dated March 7, 1985, indicating that the siren sound coverage was acceptable. The licensee agreed to forward a copy of the final report when it is received. The inspector had no further questions in this area; this item is closed.

2.2.6 (Closed) Unresolved Item (352/84-55-01): This item is related to the identification of three cases of closely spaced snubber supports during walkdown inspection of safety-related piping systems. The issue of concern was that the installation of snubbers or rigid supports in close proximity to other snubbers, rigid supports or anchors could result in one of the following:

(1) Inoperability of snubbers, leading to possible overstress of the piping system if the dead band in a snubber were less than the relative pipe translation between the two successive close snubbers.

(2) Overloading of the support and/or piping if the gap between piping and supports exceeded certain limits.

The licensee was requested to address this concern for all support installations on safety related piping systems.

The inspector reviewed various documents provided by the licensee to address this item. The documents reviewed included Finding Report number N-429 titled, "Proximity of Rigid Supports & Restraints". The report included an attachment addressing the proximate snubber review.

The overall review covered proximate snubbers and proximate rigid supports in addition to the three specific cases of closely spaced snubbers which were identified by the NRC. The evaluation of snubber actuation was performed for all seismic category I large piping systems with closely spaced snubbers, including those cases identified by the NRC. The criteria for proximity were determined as follows:

(1) Three pipe diameters or less were considered proximate for piping 8 inch diameter and larger.

(2) Five pipe diameters or less were considered proximate for piping less than 8 inch and greater than 2 inch in diameter.

(3) Ten pipe diameters or less were considered proximate for piping 2 inch in diameter and less.

The proximity criteria were established on the basis of a maximum snubber dead band of 0.04 inches and a stress level of 12,000 psi in the piping system at the location of the proximate snubber.

The evaluation was performed by reanalysis of the piping system after removing proximate snubbers from the mathematical model. For cases where pipe movement at the proximate snubber location exceeded the tested dead band value, the snubber was assumed to actuate and the original analysis was considered to be valid. Where pipe movement at the proximate snubber location was less than the dead band, the snubber was considered to be non-actuating and piping stresses and support loads were reevaluated for acceptability.

The review of large bore piping systems for proximity has identified 12 snubbers adjacent to other rigid supports, 9 snubbers adjacent to anchors, and 25 snubbers in proximity to other snubbers. The conclusion of the evaluation was that either snubber lockup was achieved or that piping stresses and support loads were acceptable for those cases where piping movement was less than the snubber dead band.

A review was also performed on all snubbers located on Nuclear Class 1 small bore piping and 25% of snubbers on Class 2 and 3 small bore piping. Four cases of proximity were identified where snubbers were supporting heavy masses. Further evaluation determined that piping displacement was greater than snubber dead band movement

The review for proximity of rigid supports focused on those cases involving supports near nozzles of rotating equipment. Four cases were determined to require support modification by providing additional shimming to limit the combined gap between the piping and both sides of the support to a maximum of 1/16".

The supports which were modified are:

HBC-508-H4
HBC-508-H5
HBC-509-H4
HBC-509-H6

These supports are installed on 20 " diameter piping for the Residual Heat Removal Service Water System.

The inspector reviewed the following documents related to the support modifications:

- o Modification Design Change Package (MDCP 335)

- o Maintenance Request forms (MRF's #8502734, 8502915, 8502916 and 8502917)

- o Procedure for ASME Section XI replacement plan for shims on the above hangers (8031-FM-67), and attached sequence control checklist and inspection record.

The licensee's action in response to the identified concerns is considered adequate. Therefore, this item is closed. However, a comprehensive review of issues related to proximity of snubbers and restraints on safety related piping systems has been forwarded by NRC Region I to the NRC Office of Inspection and Enforcement for possible generic action. Additional action may be required as a result of this review.

2.2.7 (Closed) Unresolved Item (352/84-55-02): This item is related to the evaluation of pipe support attachments to building structural steel. Two concerns were identified:

(1) No specific criteria have been provided for the inclusion and the evaluation of structural steel members for torsional moments induced by eccentric attachments.

(2) No specific criteria have been provided for the evaluation of local stresses induced by hanger support attachments to flanges and webs of building steel.

The inspector reviewed the licensee's Finding Report number N-428 and the attached report on the re-evaluation of pipe hanger attachments to structural steel in safety-related structures.

The re-evaluation effort was performed on a sample of 91 hangers which included attachment configurations depicting those general configurations of concern. The sample was selected from a population of 1192 supports, of which 311 supports were found to include attachments producing torsion and local stresses in structural steel. Thus the 91 selected supports represented approximately 29% of the hangers of concern and 8% of the total population.

In those selected samples where structural evaluation was based wholly or partially on engineering judgment, additional or supplementary calculations were performed to document the design steps required to support this judgment.

The evaluation for torsional effects was performed using an approach provided by United States Steel (USS) in its Steel Design Manual. The evaluation for local stresses resulting from attachments to flanges was performed using a generic study performed by Bechtel on Grand Gulf Nuclear Station Units 1 & 2 titled, "Stiffener Plate Requirements Study". For the purposes of those supports currently erected in Unit 1, this item is closed.

The licensee's action was determined to be adequate for the qualification of completed installations. However, the establishment of specific criteria to address those identified concerns, needs to be addressed for future modifications. The concerns, reiterated below, are:

(1) Lack of specific criteria for the inclusion and evaluation of structural steel members for torsional moments induced by eccentric attachments. The evaluation should address warping normal and shear stresses in open sections and St. Venant shear stresses in closed sections and open sections not restrained from twisting.

(2) Lack of specific criteria for the evaluation of local stresses induced by hanger attachments to flanges and webs of building steel, particularly those attachments which result in connections deviating significantly from standard steel connections.

The licensee was informed of the inspector's findings. This item is unresolved pending licensee response and NRC review. (352/85-16-01).

2.2.8 (Closed) Follow Item 50-352/84-60-01: Discrepancies exist between procedures and switch labels in the control room.

As indicated in Inspection Report 50-352/84-72, the Operations Engineer had committed to revise the TRIP, Special Event, Operational Transient and Off-Normal procedures to make the equipment nomenclature agree with that shown on control room panels prior to exceeding 5% power. The inspector determined that this work had been completed, based on a review of procedure indices annotated to indicate the status of the review by the licensee.

Additionally, the inspector noted that the licensee had commenced a review of the system operating procedures. Completion of this effort is being tracked by an operations engineer.

The inspector also reviewed a memorandum from the Technical Engineer to his staff, directing that the Surveillance Test procedures be reviewed for human factors considerations to assure these procedures would be revised during the first routine procedure review cycle.

The inspector had no further questions. This item is closed.

2.2.9 (Closed) Unresolved Item 50-352/84-65-07: Control room habitability system design and its associated Technical Specifications.

The inspector reviewed the licensee's response to this concern contained in its letter dated 2/11/85. According to the letter, the licensee agreed with the inspector's evaluation of the system design and implemented the following corrective measures. First, Technical Specification PORC Position for Table 3.3.7.1-1 was issued on 1/22/85 which prescribed actions to be taken in the event one of the four control room air supply radiation monitors becomes inoperable. These actions involved notification of a Senior Staff Engineer and repair of the monitor within 14 days. The concern regarding the chlorine detection system was resolved by the issuance of a PORC Position on 1/22/85 which identified detectors C and D as the systems governed by Technical Specifications. Regarding the need for a normal supply and return air flow path to be in operation to make the control room emergency fresh air system operable, the licensee issued another PORC Position on 1/22/85 to require at least a supply and exhaust fan with associated dampers and ducting to be operable.

The inspector reviewed the PORC Position which had been issued and associated engineering memoranda. The inspector noted that the current Position regarding the control room radiation monitors was not as conservative as the position taken by PECo engineering. The engineering position was that 1 of 4 monitors could be out for 7 days, after which the emergency fresh air system must be operated in the radiation isolation mode. The inspector discussed the difference between the PORC and engineering positions with the licensee. Subsequently on 4/15/85, a PORC Position was issued to implement the more conservative engineering position.

The inspector had no further questions. This item is closed.

2.2.10 (Closed) Follow Item 50-352/84-68-04: Performance of surveillance tests on the standby gas treatment system (SGTS) and reactor enclosure recirculation system (RERS) and closure of open preoperational test exceptions for tests 1P34.1 and 1P70.1. The inspector verified that the licensee had appropriately addressed the conditions identified as test exceptions in tests 1P34.1 and 1P70.1 that impacted initial criticality. Further, the inspector noted that during inspection 50-352/84-71, the acceptable performance of surveillance tests for SGTS and RERS was verified in connection with closure of NRC open item 50-352/84-57-09. Consequently, the inspector had no further questions related to item 50-352/84-68-04, and this item is closed.

2.2.11 (Closed) Follow Item 50-352/85-02-01: Licensee to improve the quality of operating logs and records. The inspector's review of shift operating logs has indicated that an adequate improvement has been achieved. Especially noteworthy has been the improvement shown in the Shift Supervisor's log. Additionally, review of complete daily surveillance procedures by the inspector has indicated improvement in that all entries are now made in pen and corrections to the data are properly made. This item is closed.

2.2.12 (Closed) Follow Item 50-352/85-02-04: Safeguard fill isolation valve found out of position.

The licensee's investigation of the mispositioning of the 1B safeguard fill to HPCI isolation valve, 55-1047 indicated that the cause of the mispositioning was an incorrectly performed system valve lineup. The valve was correctly positioned after the inspector identified the problem. Further, the Operations Engineer issued a training memorandum to the shift, dated 4/17/85, to discuss the event.

2.2.13 (Closed) Unresolved Item 50-352/85-02-05: Unsealed penetrations in the floor of the diesel generator corridor.

During this inspection period, a region-based fire protection specialist reviewed the concern regarding unsealed penetrations through the floor of the diesel generator corridor into the service water pipe tunnel. This inspector concurred with the licensee's evaluation that no significant fire safety hazard had been caused by not sealing these penetrations. The inspector understood that the licensee would modify the Fire Protection Evaluation Report to remove the need for these seals and considered this action as being warranted. This item is closed.

2.2.14 (Closed) Follow Item 50-352/85-03-02: Control Room Accessibility.

The inspector reviewed the actions taken by the licensee to control access into the Control Room. These actions included:

- o administrative controls limiting the number of individuals who had access from the fifth floor of the Administration Building
- o a new computer code given to individuals authorized access through the fifth floor Administration Building door
- o a review, conducted every 31 days, of the list of individuals authorized access
- o a sign on the door to the Control Room explaining the changes
- o foot traffic control directions on the floor, illustrated in colored tape and black print

The inspector toured the control room and observed that the above items have been instituted. The inspector had no further questions. This item is closed.

2.2.15 (Closed) Follow Item 50-352/85-03-07: Document Control for Environmental Qualification Reports (EQRs) on Mechanical and Electrical Equipment.

To ensure that individuals required to use the Mechanical and Electrical EQRs have complete, up-to-date copies, the licensee approved new procedures that control the issuance of EQRs, maintenance of a register of individuals who receive the EQRs, and the issuance of revisions to the EQRs. These procedures are:

- o EE-6.1 Procedure for control of the EWR for PBAPS and LGS
- o ME-6.1 Procedure for control of the Mechanical EQR for LGS

The inspector reviewed both procedures and concluded that the measures required to control EQRs are adequate. This item is closed.

2.2.16 (Closed) Follow Item 50-352/85-03-08: Licensee to provide a management information system to track the status of maintenance.

The inspector determined that, as of 2/8/85, the licensee had developed and implemented a system wherein maintenance status is reported weekly to senior station staff, including the Station Superintendent. These reports include the status of both corrective and preventive maintenance request forms (MRF) along with the backlog of MRFs awaiting either a forced outage or deferred to a refueling outage. The reports compare the total MRFs outstanding (i.e., work incomplete) between the given week and the previous week, thus providing trending information relative to the MRF backlog. The inspector had no further questions. This item is closed.

2.2.17 (Closed) Follow Item 50-352/85-03-10: Licensee to implement an administrative system for the control of scaffolding in safety-related areas.

The inspector reviewed Administrative Procedure A-30.1 which established controls over temporary scaffolds and work structures in the plant. These controls included a tagging system for marking authorized use of these temporary services along with a review by a supervisory level individual from Maintenance Division to assure the scaffolds/structures do not impact on equipment access or operation. This item is closed.

2.2.18 (Closed) Follow Item 50-352/85-03-14: Licensee to include a requirement for a valve lineup of the Automatic Depressurization System (ADS) into its startup procedures.

The inspector verified that a requirement to perform a valve lineup for the ADS in accordance with procedure S50.1 had been added into revision 4 of General Procedure GP-2, Normal Plant Startup. Additionally, in GP-2, the licensee required a valve lineup per procedure S59.1 (Checkoff List 2) which includes ADS valves inside containment. Differences between the component nomenclature on the control room panels and that contained in S50.1 have been resolved.

2.2.19 (Closed) Unresolved Item 50-352/85-20-01: Licensee actions required to be completed prior to the initial turbine roll activities.

The following items were reviewed, performed or witnessed to close out this item. PECo safety evaluation for conducting turbine roll activities was issued on April 4, 1985. Temporary Procedure Change No. 623 was issued to interface GP-2 "Normal Plant Startup" with plant limitations due to the 5% licensed steady state power level, SP-GP-006 "Main Turbine Initial Startup", Revision 1, dated April 5, 1985 and testing schedule logic. SP-GP-007 "Shutdown of Main

Turbine During Low Power Testing", Revision 0, dated April 5, 1985 was issued to control turbine shutdown operations to minimize conditions that may cause pressure or power perturbations. Training of plant personnel including plant supervision, operators and test personnel was conducted on the overall test sequence as well as specific tasks to be performed to conduct each testing phase. SP-GP-006 contained hold points prior to proceeding with the next phase of testing to assure safe operation. Hold point authorization required the Plant Superintendent or his designee and the lead GE representative authorization. The licensee did review the plant response in prior test phases to assure safe operation in the next phase prior to releasing the hold condition and did establish limiting criteria for safe operation. Based on the above and witnessing of activities relating to the turbine roll activities for the initial sounding roll and initial turbine roll to rated speed (1800 rpm), this item is closed.

2.3 Three Mile Island (TMI) Action Plan Items

2.3.1 (Closed) TMI Item I.G.1: Training During Low Power Testing

This item required that the licensee establish a special low-power test program as approved by the NRC and provide supplemental training to the station operators during this test program. The inspector noted that the low power test program, as defined in Chapter 14 of the FSAR had been reviewed and approved by NRR. NRC inspectors routinely monitor the licensee's performance of the test program to verify it to be in full compliance with the FSAR. The inspector also noted that, because several low-power tests were performed multiple times, added training benefit was achieved by the station operators.

Regarding the extra simulator training committed to by the licensee in its 3/6/81 letter to NRR and described in its response to FSAR question 640.11, the inspector reviewed the course outline and list of attendees for the training given to the operators in the response to a station blackout transient during November - December 1984.

The inspector had no further questions; this item is closed.

2.3.2 (Closed) Item II.B.2: Plant Shielding

This TMI Action Plan item required the licensee to perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive material. The review was to identify those areas in which personnel occupancy may have been unduly limited or safety equipment may have been unduly degraded by post-accident radiation fields. The results of the licensee's review were documented in section 1.13 of the FSAR.

The NRC Office of Nuclear Reactor Regulation reviewed the information provided in the Final Safety Analysis Report (FSAR) and documented the results of its review in section 12.3.2 of the Safety Evaluation Report (SER).

As stated in both the FSAR and the SER, the vital areas assumed to require continuous personnel access were the main control room, the technical support center, the operations support center and the security center. Infrequent access would be required for the counting room, the radiochemistry laboratory, the post-accident sampling sink, the north stack instrument room, the HVAC panels on elevation 304 of the control enclosure, the radwaste control room and the diesel generator enclosures. The FSAR listed, in tables, the expected exposure rates and doses for each of the above listed areas and identified paths throughout the plant which could be followed to safely travel from one vital area to another.

The inspector reviewed the FSAR and the SER, then he reviewed a selection of emergency operating procedures and verified that these procedures could be successfully implemented by manipulation of only the equipment and controls operable from within the vital areas. Included in this review were those loss-of-coolant related TRIP and Special Event Procedures listed below:

T-101 Reactor Pressure Vessel Control
T-102 Containment Control
T-111 Level Restoration
T-112 Emergency Blowdown
T-113 Blowdown Cooling
T-114 Spray Cooling
T-115 Alternate Shutdown Cooling
T-116 Reactor Pressure Vessel Flooding

T-117 Level/Power Control
SE-10 LOCA

Several of the above TRIP procedures referenced other procedures such as T-200, 230, 231, 232, 233, 234, 235, 243, 244 and 250.

In all but the case of SE-10, the inspector verified that the licensee would not be radiologically restrained from performing the actions specified in the procedures to combat an accident. Regarding SE-10, there were steps requiring an operator to close the power supply feeder breakers to the valves in the main steam isolation valve leakage collection system at the local motor control centers in the reactor enclosure. However, the shield design review indicated that the reactor enclosure would be inaccessible after a design-basis loss of coolant accident. This problem was previously identified by the NRC during inspection 85-03 and the licensee's actions to address this problem will be reviewed in connection with the concern identified in that report. The inspector had no further questions; this item is closed.

2.4 Part 21 Reports

(Closed) Part 21 Report 50-352/84-88-06: General Electric TOPAZ Inverters.

General Electric informed NRC and the licensee of an apparent problem with the Topaz inverters supplied as part of the installation for the RHR/Core Spray, HPCI, RCIC and remote shutdown panel systems. The problem involved an inappropriately set low voltage cutoff setpoint for the inverter. Due to an engineering error, the inverter low voltage cutoff had been set at 105V instead of around 100 VDC. As a result, under worst case conditions during startup of large DC loads, the incoming DC voltage could dip to the 105 VDC level, causing a trip of the inverter. The inverter would not turn back on until DC voltage recovered to about 118 VDC. GE revised its criteria such that the low voltage trips should be set at no greater than 100 V with a reset at about 108 VDC.

The inspector reviewed MDCP 363, maintenance request form 8502904 and GE FDI-TNVB which documented completion of the prescribed corrective action. Based on the inspector's review, this item is closed.

2.5 IE Bulletins and Circulars

2.5.1 (Closed) IE Circular 80-05: Emergency Diesel-Generator Lubricating Oil Addition and Onsite Supply

This Circular described a problem which occurred as a result of lube oil being improperly added to an operating emergency diesel generator (EDG). The Circular recommended that licensees verify the existence and adequacy of procedures for adding lube oil to safety-related equipment, to verify that appropriate training has been conducted regarding adding oil to operating EDGs, to check that the oil fill connections for the EDGs were adequately identified, and to determine the lube oil usage rate for a fully loaded EDG and show that oil supplies are adequate.

Procedures for adding oil to safety-related equipment

The inspector identified that procedures had been implemented which discussed the proper methods of adding oil to the EDGs, the standby liquid control, RHR, and core spray pumps and the RCIC and HPCI turbine/pumps. These procedures included: S92.9N, S12.9A, S48.9A, S49.9A, S51.9A, S52.9A, S55.9A, PMQ-048-008, PMQ-056-030 and PMQ-500-006.

Personnel Training

The inspector noted that operators had been trained by the vendor on the diesel generator and its auxiliary systems which included training on the lube oil system.

Marking of EDG Lube oil fill connections

The inspector reviewed Quality Assurance surveillance report M-485, performed 4/12/85. This report indicated that the EDG lube oil fill lines are hard-piped from the lube oil makeup tank through globe valves. These valves are adequately identified by the component tags on the valves which list the valve number and function.

Lube Oil Usage Rates

The inspector noted that, during preoperational test 1P100.4, the lube oil usage rate of each of the 4 EDGs was shown to be such that greater than 175 hours of operating time at full load was assured provided the lube oil storage tank was 100 percent full. Additionally, the inspector reviewed routine test RT-6-092-640-1 which would periodically reperform the lube oil consumption rate test. The inspector questioned the use of 2 gallons per hour as the allowable oil usage rate in the RT. At 2 GPH, about 5.8 days of oil are available in each storage tank. If the storage tanks were initially less than 100% full, less running time would be available.

The licensee then showed the inspector a field material requisition for 12 barrels of lube oil to be marked "Diesel Generator Emergency Use Only" and stored in the Bechtel Long Term Storage Building. The licensee also informed the inspector that section 9 of the FSAR would be revised to indicate that 7 days of lube oil would be available onsite instead of indicating that the lube oil storage tanks had sufficient capacity for 7 days of operation.

The inspector had no further questions; this item is closed.

2.5.2 (Open) IE Bulletin 84-01: Cracks in Boiling Water Reactor Mark I Containment Vent Headers

This Bulletin pertained to a problem which occurred at Hatch, Unit 2, wherein cracks developed in the containment vent header as a result of the impingement of cold nitrogen gas during containment inerting. Although the licensee was not required to take specific action regarding this Bulletin for Limerick, which uses a Mark II Containment, it was expected to review the document for information.

Subsequent to issuance of the Bulletin, General Electric (GE) issued Service Information Letter (SIL) No. 402 regarding wetwell/drywell inerting. The SIL addressed the same concerns as the Bulletin, but provided recommendations for licensee actions for those facilities using Mark II containments such as Limerick. The SIL recommended that licensees: 1) evaluate the inerting system design to determine the potential for introducing cold nitrogen onto containment downcomers and other equipment which might be in the path of the injected nitrogen; 2) evaluate the overall system design including temperature monitoring devices and the low temperature shutoff valve; 3) evaluate the operation of the inerting system; and 4) evaluate the procedures for system operation, maintenance and component calibration.

The inspector reviewed a PECo Mechanical Engineering internal memorandum, dated July 25, 1984, which documented the completion of the reviews necessary to meet items 1, 2 and 3 above. The results of the reviews indicated that several pieces of safety-related equipment were located within the primary containment in relatively close proximity to both the high volume and low volume inerting line penetrations. The licensee determined that modifications to the inerting system were sufficient to address the concern rather than proposing equipment modifications to move the components identified during the review. As described in a letter to NRC from the licensee, dated 9/26/84, the modifications to be performed included work on both the storage and vaporizer skid and work in the distribution piping system. On the skid, the vendor (Union Carbide-Linde Division) was to implement changes to replace and relocate the existing switch which controls the low temperature shutoff valves, to remove the existing manual bypass path around the low temperature shutoff valves and to provide an ambient vaporizer and a topping heater to eliminate dependence on the availability of auxiliary steam during low flow operations. Regarding the distribution piping system, modifications were planned to provide an automatic low temperature isolation signal to an inerting line containment isolation valve and to provide control room indication of the temperature of the nitrogen gas being supplied to the containment.

The inspector reviewed modification MDCP 0197 and maintenance request forms (MRFs) 8502564, 2565, 2566, 2676, 2677, 2678, 2680, 2776 and 2927 which implemented the distribution system changes. The MRFs added temperature element TE-57-060 and associated switches and relays which controlled an indication and alarm in the control room and provided an automatic high or low temperature closure signal to valve HV-57-160A. Valve HV 57-160A is one of two valves in the 6" distribution header from the nitrogen storage facility upstream of the high or low volume inerting lines. The inspector also field checked the installation of the recorder and the alarm in the control room and reviewed applicable calibration and circuit test records. The inspector noted, however, that there were no documented plans to periodically calibrate or functionally test the instrumentation or logic covered by the MDCP. The inspector discussed this matter with the station Instrumentation and Control Engineer who informed the inspector that test procedures would be developed.

Regarding the modifications Linde intends to make to the storage and vaporizer skid, the inspector determined that the designs had not been finalized and no MDCP existed covering this work. The inspector noted that licensee had indicated in its 9/26/84 letter that these modifications would be completed prior to the initial inerting of the containment, currently scheduled for 6 months after initial criticality (i.e., June 22, 1985).

This Bulletin will remain open pending the completion of the modifications to the storage and vaporizer skid and implementation of appropriate calibration and functional test procedures for the instrumentation installed by MDCP 0197.

3. Plant Tour

3.1 Unit 1

Periodically during the inspection period, the inspectors toured the Unit 1 containment, the reactor enclosure, the control enclosure, the turbine enclosure, the diesel generator enclosures, the radwaste enclosure, the off-gas enclosure, and the site perimeter outside the power block. The inspectors examined preventive and corrective maintenance, surveillance testing, tagging of equipment, housekeeping, radiological control practices, portal monitoring, security, lighting, vehicular control, power block control points, security fencing, fire protection equipment, environmental controls, and general plant operations. The inspectors routinely toured the control room to verify proper control room manning, procedural compliance, safety system availability, and nuclear instrumentation operability. Operating logs, the jumper-bypass log, the temporary circuit alteration (TCA) log, operating orders and plant trouble reports were reviewed to verify that all technical specification requirements were met. Interviews and discussions were routinely conducted with licensee operators and staff concerning the status of off-normal alarms, compliance with technical specifications and general plant conditions.

Valve and switch lineup verification checks were performed on the 'B' loop of the Core Spray System, the 4 kv and 480 VAC Safeguard MCC power systems and the A and B trains of the control room emergency fresh air system.

No violations were identified.

3.1.1 Valve Lineup Discrepancies In the Control Room Emergency Fresh Air System

On 4/18/85, the inspector conducted an independent valve lineup on the control room emergency fresh air system (CREFAS) using a version of system checkoff list (COL) S78.1B, which had been verified appropriate by the inspector. Several discrepancies were identified. One minor problem involved the COL itself, in that it failed to include valves HV 78-0005A and B with their associated caps. The valves were noted to be closed, as required, and the caps installed. The licensee was informed of this problem. Other discrepancies involved mispositioned valves on the fire protection deluge connections to the charcoal filter trains. The inspector noted that valves HV78-0010A and B, the A and B CREFAS supply filter deluge line drain valves, were open and their associated pipe end caps removed. Per COL S78.1B and P and ID M-78, these valves were required to be closed and the pipe stubs capped.

The inspector notified the control room operators of his findings and inquired about the cause of the lineup problems and about impact of the mispositioned valves on CREFAS operability. To address this matter, the Test Engineer responsible for CREFAS examined the fire deluge penetrations into the filters and discussed with the vendor whether a path had been established for control room supply air to bypass the charcoal due to the opened valves. The inspector was informed that the vendor indicated that the fire lines are surrounded by charcoal media such that any air inleakage through the fire lines would be treated prior to its entry into the control room.

Regarding the cause for the event, the inspector was informed that the drain valves involved probably were open because the fire deluge isolation valves leaked-by slightly and periodic draining was necessary to prevent the wetting of the charcoal. As corrective actions, the licensee closed and capped HV-78-0010A and B and placed them on the routine rounds made by the non-licensed operators once per shift. These operators would then periodically remove the caps and open the valves to drain what moisture had accumulated in the lines. Additionally, the inspector was informed that a modification was being proposed to provide a permanent leakoff connection for the fire system at the filters. Independently, the inspector verified that the valve positions for the deluge supplies were correct for the charcoal filters in the standby gas treatment system, the reactor enclosure recirculation system, and the reactor enclosure equipment compartment exhaust system.

No violations were identified.

3.1.2 Potential Problem Found in General Electric Drawings

During the week of 4/22-27/85, consultants from the Brookhaven National Laboratory performed a PRA-based inspection regarding the preoperational and surveillance testing of the automatic depressurization system (ADS). During the course of this inspection, the consultants identified that, as a result of the licensee not revising GE-supplied drawings on a priority basis after system modifications, and as a result of an error made by the Bechtel document control organization, there exists a potential that up to 400 controlled drawings onsite may not reflect the as-built conditions of the plant. The details of this finding will be issued in contractor's subsequent report. However, the inspector reviewed the licensee's actions in this matter.

The inspector determined that, as of 4/27/85, the licensee restricted work on the systems affected by the 400 drawings. The restrictions were such that no temporary circuit alterations or troubleshooting activities could occur on the systems without specific approval by the Plant Operations Review Committee. These restrictions would remain in place until the accuracy of the 400 drawings could be verified. This verification is expected to be complete by 5/3/85.

No violations were identified.

3.2 <u>Unit 2</u>

The inspector periodically toured the Unit 2 reactor enclosure including the drywell and the Unit 2 side of the turbine enclosure. These tours were conducted to verify adequate housekeeping and in-storage maintenance of equipment during the suspension of construction activities.

No violations were identified.

4.0 <u>Review of Licensee Compliance To Selected License Conditions</u>

The inspector reviewed the licensee actions taken to comply with selected conditions of the low power operating license, NPF-27. This review was confined to those conditions which described actions to be completed by the licensee prior to it seeking to increase reactor power above 5 percent. Those License Conditions reviewed and the licensee's actions are described below:

4.1 (Closed) License Condition 18: Ultimate Heat Sink:

In accordance with License Condition 18 to NPF-27, the licensee was required to develop and implement plant procedures addressing (a) the methods and resources for repair of spray pond piping, (b) operation of the spray pond in either the closed cycle or once through cooling modes,(c) restoration of offsite power to the Schuylkill River makeup pumphouse, and (d) the verification of availability of portable pumps to pump water from the Schuylkill River to the spray pond pumphouse wetwells.

In this regard, the licensee met with representatives of NRR on 12/20/84 and presented drafts of those procedures which were responsive to this License Condition. During this inspection period, the inspector verified that the draft procedures discussed at the 12/20/84 meeting had been formally approved and issued. These procedures included the system operating procedures for the emergency service water, RHR service water, Schuylkill River pumphouse and Perkiomen pumphouse systems along with the following special procedures:

Procedure	Description
SE-9 High Winds	Provides actions to be taken during/after high wind conditions such as tornados and provides a flow chart to implement the backup ultimate heat sink procedures.
SE-9 Appendix A	Provides procedural and logistical information necessary to pump water from the Schuylkill River to a cooling tower basin using portable pumps.
SE-9 Appendix B	Provides procedural and logistical information necessary to make emergency repairs to the cooling tower basins.
SE-9 Appendix C	Provides procedures to supply power to the Schuylkill River pumphouse if offsite power is lost.
S12.7.C	Provides the procedures for establishing a cooling water supply flowpath from the Schuylkill River or the Perkiomen Creek through a cooling tower to the ESW/RHRSW wet pit and a discharge path from the spray pond to the Schuylkill River.

CPL-11 — Provides procedural and logistical information for emergency repairs to the spray pond networks.

The inspector had no further questions and identified no violations.

4.2 (Closed) License Condition 8(b) Safety Parameter Display System

As required by NPF-27, the licensee was to have made the Safety Parameter Display System (SPDS) operable by 4/1/85. However, in a letter dated 3/18/85, the licensee informed the NRC that additional validation testing of the SPDS would result in it not being fully operable by the required time. Further in the 3/18/85 letter, the licensee described an interim SPDS which could be declared operable by 4/1, using those aspects of the General Electric-supplied Emergency Response Facility Data System (ERFDS) currently in place. In response to the licensee's 3/18/85 letter, NRR informed the licensee, in a 3/27/85 letter, that rather than NRC conducting a review of the interim SPDS for acceptability, the licensee should request an amendment to NPF-27 to reflect the schedule revision necessary to accommodate the completion of validation testing of the original SPDS system.

Accordingly, in letters dated 3/29/85 and 4/9/85, the licensee formally requested an extension of the schedule for SPDS operability. The licensee requested that SPDS be required operable within 30 days after the completion of the 100-Hour Warranty Run at 100 percent power. As justification for continued operation, the licensee stated that the parameters which are monitored by the SPDS are available to the operators through hardwired, qualified instruments with readouts in the control room. The licensee indicated that the parameters available in the control room included those associated wth steps in the abnormal and emergency procedures used for responding to significant events. The licensee also indicated that operators received training involving these procedures during initial licensing and requalification training. Further, the licensee indicated that radiological information required during responses to significant events is currently available in the control room and Technical Support Center using the Radiation and Meteorological Monitoring System (RMMS).

The inspector noted, during review of systems and witnessing of emergency exercises, that the instrumentation available in the control room appeared adequate for implementation of event response procedure. Further, the inspector has observed that operators appeared well trained in the use of these instruments and procedures. Additionally, the inspector noted that the RMMS has been in service throughout low power operation. Final acceptability of the licensee's request for revision of the schedule for this item is currently being reviewed by NRR in connection with the issuance of a full power license. Consequently, the inspector considers this item closed with respect to its impact on the low power license.

5.0 Preoperational Test Exception Review and Closeout

The inspector reviewed the licensee's dispositions of the following preoperational test exceptions (TEs) to assess their technical adequacy and to verify that these exceptions had been suitably resolved. These TEs had been prioritized as being required to be resolved prior to exceeding 5 percent reactor power.

Preoperational Test		Test Exception Number
1P34.1	Reactor Enclosure HVAC	13D, 130, 13S
1P41.1	Cooling Tower Systems	7
1P44.1	Condensate System	15
1P45.1	Feedwater	52, 72

No problems were identified.

6.0 Review of Events Which Occurred During This Reporting Period

6.1 Standby Liquid Control Tank Chemistry Specification Not Met

On 3/22/85, the licensee identified that the amount of sodium pentaborate contained in the net usable volume of the standby liquid control tank (SBLC) was less than the 5500 lbs. required by Technical Specification 3.1.5. The problem had resulted from a faulty surveillance test procedure which had been in use since 10/25/84 to analyze the sodium pentaborate concentration in the SBLC tank. In response to the identification of the problem, the licensee promptly added the necessary chemicals to return the weight of sodium pentaborate to an acceptable level.

The inspector reviewed the suspected licensee event report which was written to document the above problem. The inspector also interviewed members of the site chemistry and operations organizations to determine how the event was identified, the event's cause and the licensee's corrective actions.

The inspector learned that a newly-hired operations engineer had been familiarizing himself with SBLC system design, operations and technical specification (TS) requirements when he noted that the TSs discussed the term "net volume" when there were references to the amount of sodium pentaborate available for injection into the reactor vessel. Further followup indicated to the operations engineer that the bottom 7 inches of the SBLC tank were to be considered unusable because the low tank level automatic SBLC pump shutoff signals occurred at this point. However, he noted that the surveillance test procedure used to analyze the chemistry of the SBLC tank, ST-5-048-800-1 Revision 2, assumed that the entire contents of the tank would be available and thus it failed to properly account for the sodium pentaborate which would remain in the lower 7 inches of the tank. The engineer informed site chemists of this problem and the chemists' review substantiated the engineer's concern. At that point, corrective actions were begun.

The inspector obtained the results of each performance of ST-5-048-800-1 between 10/15/84 and 3/23/85 to assess the extent to which the 5500 lb. requirement was not met. Observing that operability of the SBLC system is only required in Operational Conditions (OPCONs) 1, 2 and 5, the inspector determined that TS 3.1.5 had not been met on 10/26-11/13/84 (initial fuel load OPCON 5), 12/22/84 (initial criticality OPCON 2), 12/29-1/15/85 (OPCON 2), 1/18-31/85 (OPCON 2) and 2/17-28/85 (OPCON 2). During these periods, the sodium pentaborate weights available for injection ranged from about 1 to 5 percent below the 5500 lb. requirement.

The inspector then met with the Station Superintendent, the Senior Chemist, the Reactor Engineer and the Power Generation Engineer on 3/29/85 to further discuss this matter. At this meeting, the inspector learned from the Reactor Engineer that the General Electric design basis for anticipated transient without scram (ATWS) events assumed that the SBLC system would be capable of achieving a 2.6% shutdown condition in the reactor. An analysis of the Limerick design indicates that a 6.1 % shutdown can be achieved with enough sodium pentaborate injected to result in a 600 ppm concentration in the vessel. At Limerick, the injection of 5500 lb. of sodium pentaborate should result in at least a 660 ppm concentration in the vessel even with allowance for a 25% reduction in concentration to account for poor mixing and for filling other process piping attached to the vessel. The Reactor Engineer concluded that,during the time in which the weight of available sodium pentaborate in the SBLC tank was the least, the system was still capable of injecting the chemicals needed to exceed a 600 ppm concentration in the vessel. Thus, the safety significance of this event was minor. The inspector agreed with this assessment.

The Power Generation Engineer informed the inspector that on 3/28/85, the station had become aware of a requirement from General Electric to further raise the liquid level in the SBLC tank at which the SBLC pumps automatically trip. This change was due to new environmental qualification data on the level transmitters for the tank. The change would render the lower 11.8 inches of the tank unusable. Accordingly, on 3/28/85 the setpoints were changed, ST-5-048-800-1 was revised and chemicals were added to the SBLC tank to assure the 5500 lb. requirement would still be met.

The inspector then inquired about the level of review the surveillance test procedure had received prior to its issuance on 10/25/84. The inspector learned that ST-5-048-800-1, revision 2 had been drafted by a plant chemist and had been reviewed by a sub-PORC made up only of chemistry personnel. The inspector indicated to the Station Superintendent that a multidisciplinary review of the ST, as required by TS 6.8.1 and procedure A-4, might have averted the problems encountered. Further, the inspector informed the Station Superintendent that not performing an appropriate multidisciplinary review of ST-5-048-800-1 revision 2 constituted a violation. (50-352/85-16-02)

6.2 Spurious Engineered Safety Features (ESF) Actuation on March 26, 1985

At 8:20 a.m., 3/26/85, a spurious actuation of the Division 2 ESF systems occurred as a result of an error made by an instrumentation and controls technician. At the time, the plant was in Cold Shutdown, with the reactor coolant system depressurized and at about 160 degrees F.

The technician was attempting to backfill the variable leg of reactor pressure vessel (RPV) fuel zone level transmitter, LT 42-1N085B, with a pressurized source of demineralized water. The water source was connected to the common drain header for the instruments located on rack 10C010 at the 217 ft. elevation of the reactor enclosure.

As per the controlling procedure, ST 2-036-630-1, the technician was required to open the transmitter's variable leg drain valve to flush the line back to the reactor. The technician, standing in front of the instrument rack, attempted to locate the proper drain valve by following the instrument tubing from the transmitter to the drain valve. This process was necessary because the ST did not identify the valve numbers; rather it used the functional descriptions of the valves involved (i.e., Drain Valve, High Side Instrument Valve etc.). The technician, however, mistakenly located the drain valve for the instrument's reference leg. When the technician opened the drain valve, he pressurized the reference leg line, which is also used as the reference leg to various Division 2 RPV level and pressure transmitters.

The increase in reference leg pressures to the other level transmitters caused RPV low level, level 1, 2 and 3 trips of the trip units fed by these transmitters. As a result, Division 2 LOCA actuations occurred. The B residual heat removal pump started and injected into the vessel in the low pressure coolant injection (LPCI) mode. In addition, the D12 diesel generator started but did not close into the D12 4160V safeguard bus because offsite power was available; the loads on the D12 bus were shed and were sequenced back in as was expected for the LOCA signal; a channel B half-scram occurred; and various Division 2 nuclear steam shutoff system isolations occurred. The B core spray pump was out of service at the time of the event and thus did not start during the event. However, the B core spray loop injection valve opened as designed. The operators reset the LOCA actuations and returned all ESF equipment except the D12 diesel generator to the normal lineup. The diesel generator was maintained in operation.

While the above actuations were occurring, the instrument technician noted a change in plant conditions, including an alarm from an area radiation monitor (ARM) in the vicinity of the instrument rack. He closed the drain valve, verified that the ARM sounded on loss of power and contacted the control room to determine if he had been the cause of the problems. The operator he contacted indicated that the technician might not have been the cause, so the technician returned to the rack and again opened the incorrect drain valve at about 8:27 a.m., which again caused ESF actuations. Following the second set of actuations, the control room operators determined that the technician was causing the problems and directed him to stop work. The ESF systems were then returned to normal by about 9:40 a.m. It was estimated that about 8000 gallons of water were injected into the vessel by both LPCI actuations.

During a control room tour at about 11:30 a.m., the inspector noted that the B safeguard battery voltage was less than the required 262 volts DC minimum and noted a Division 2 safeguard battery charger trouble alarm. The inspector notified a control room operator who detailed a floor operator to investigate the problem. The floor operator reset the battery charger, which cleared the trouble alarm and increased battery voltage to about 270 VDC. Based on a review of the system operating procedure, S95.1A, the inspector determined that the battery chargers are susceptible to tripping on high DC voltage when they are reenergized following loss of power. Power was lost as a result of the load shedding which occurred due to the LOCA signal.

The inspector discussed plans regarding further instrument backfilling operations planned for this outage and licensee post-event corrective actions with the Station Superintendent and the station senior staff on 3/26 and on 4/9/85. These actions included: 1) revision of the ST procedure to add a caution regarding the need for care in locating the correct valves when backfilling a transmitter; 2) counselling of the technician involved; and, 3) discussion of the event at a Research and Testing department meeting. The inspector discussed with the station's Instrumenation and Controls Engineer the addition of an appendix to the ST procedure which would identify the block, equalizer and drain valves associated with each instrument to be backfilled by valve numbers. The Engineer agreed that this was appropriate and directed that the section of the ST procedure used for independent verification of the instruments' return to service include a table listing each instrument and its associated valves by valve number. The inspector had no further questions.

6.3 Inadvertent Division 4 Engineered Safety Features Actuation on 3/30/85

At 9:11 p.m., 3/30/85, with the plant in Cold Shutdown, the Division 4 engineered safety features systems inadvertently actuated. As a result, a channel B2 half-scram occurred along with automatic starts of the D RHR and D core spray pumps and, the D14 diesel generator. Additionally, various containment isolation valves received an automatic close signal. Offsite power was available so the diesel generator did not close into the D14 bus. Operators quickly terminated the vessel injection by securing the RHR and core spray pumps, but not before reactor vessel water level increased by 10 inches. All systems were subsequently returned to their normal lineup and an ENS call was made.

The licensee investigated this event to determine its cause. Results of this investigation indicated that the most probable cause was a misalignment of the equalizing valve for differential pressure instrument PDS-59-106B following performance of surveillance test ST-2-059-603-1. The differential pressure instrument monitors the difference between the instrument gas header pressure and drywell pressure to close the instrument gas containment isolation valve on a low differential pressure. The sensing line for drywell pressure for this d/p instrument is common to pressure transmitters PT-42-1N094D and H and PT-42-C71-1N050D which in turn provide high drywell pressure signals to the emergency core cooling system and reactor protection system logics.

The inspector discussed the corrective actions which had been taken or are planned regarding this event with the Station Instrumentation and Controls Engineer on 4/9/85. These actions included plans to revise the ST procedure to require closure of an additional isolation valve on the instrument gas side of the PDS transmitter prior to performance of the test. Additionally, the technicians involved were counseled on the need for care during instrument valve manipulations and the event was discussed at a departmental meeting.

The inspector had no further questions.

6.4 Spurious Halon System Injection Into the Auxiliary Equipment Room on 4/10/85

At about 1:40 p.m., 4/10/85, a spurious trip of a rate-of-temperature-rise heat detector located under a floor panel in the Auxiliary Equipment Room (AER) resulted in a Halon system injection into the room. The entire charge of Halon in the main bank of storage bottles injected as designed. Personnel in the AER evacuated as required and the fire brigade responded to the scene. At the time of the event, some of the floor panels had been removed to permit corrective maintenance work. As a result, the Halon spread throughout the AER atmosphere.

Shortly after the injection, the toxic gas detectors which monitor the control room air supply alarmed and indicated high concentrations of vinyl chloride and ehtylene oxide. As per Special Event procedure SE-2, the control room operators initiated a chlorine isolation of the control room HVAC system. Self-contained breathing apparatus was broken out, but not donned and the control room was cleared of non-essential personnel.

The licensee reported this event via the ENS on 4/10/85.

Results of the licensee's investigation of this event indicated that, just prior to the Halon injection, the in-service AER air supply fan had tripped. As designed, about 40 seconds expired before the standby air supply fan started. During those 40 seconds, the AER air exhaust fan continued to operate and a vacuum was rapidly drawn in the room. According to the heat detector manufacturer (Edwards), the rate-of-rise instruments are susceptible to tripping in response to rapid ambient pressure changes. Therefore, it appeared the vacuum drawn in the AER resulted in the trip of one heat detector and subsequent Halon injection. Further, during the time that only an exhaust fan was running, an unexpected flow path developed whereby the Halon from the AER atmosphere traveled, by way of the AER air exhaust system, back to the control enclosure air supply plenum and then past the toxic gas monitors. These toxic gas monitors measure the infrared absorption characteristics of the gas in the air supply and are calibrated to identify five gases: ammonia, ethylene oxide, formaldehyde, vinyl chloride and phosgene. Apparently, Halon being a hydrocarbon, absorbs infrared radiation similarly to some of the above gases. Therefore, the toxic gas monitors detect Halon but identify it as one or more of the gases for which they are calibrated.

As corrective actions for this event, the licensee disabled the Halon injection system for the Auxiliary Equipment Room and posted a continuous fire watch. Concurrently, the licensee's engineering organization was developing a modification to eliminate the susceptibility of the heat detectors to ambient pressure changes. A suspected Licensee Event Report was prepared by the licensee to describe the cause and consequences of this event.

The inspector had no further questions.

7.0 Fire Protection Program Implementation

7.1 Fire Damper Functional Testing

The inspector noted that although the licensee fully complies with fire Technical Specification requirements to visually inspect all fire dampers every 18 months, the licensee does not have a program to functionally test the fire dampers.

The licensee committed to establish a program to functionally test every 18 months a 10% sample of dampers based on damper type and service, with consideration given to damper accessibility, ALARA and industrial safety. The test of the dampers will follow the guidelines given in NFPA-90A. The licensee's activities in this regard will be reviewed during a subsequent inspection (IFI 50-352/85-16-03).

7.2 Fire Watches

The inspector noted that the licensee has a fire watch program as an interim compensatory measure for surveillance of areas with degraded fire protection system components. The inspector, in reviewing various suspected LERs observed that, in at least 2 instances, the hourly fire watches signed the fire watch log 7 minutes and 17 minutes later than the required 60 minutes. This latter interval exceeds, by 2 minutes, the interval of the surveillance requirement of TS section 4.0.2. The licensee's corrective action includes increased instruction to the fire watches to complete their rounds within the required time intervals and also a review of the procedure for establishing and terminating the fire watches.

The inspector verified that fire watches complete their rounds on time and the incidents identified above were isolated. The inspector had no further questions and identified no violations.

7.3 Fire Alarms

The inspector observed that a number of false fire alarms occur at this facility. The false alarms have been caused by the actuation of fire detection equipment located in areas of smoke producing processes. Specific examples involves the welding area in the Maintenance Shop and the Diesel Generator areas.

Each fire alarm requires operator action and fire brigade response. Although the inspectors have noted that the operators' response to these alarms has been adequate, these actions may be disruptive to normal plant operation since they divert operator attention while they respond to the false alarm. The inspector discussed this concern with the Station Superintendent who agreed to review the matter.

8.0 Licensee's Response to Selected Safety Issues

The inspector evaluated the training provided to licensed operators and reactor engineers and the procedures implemented to avoid events involving mispositioning of control rods. The actions taken by the licensee were assessed for their adequacy in handling the control rod positioning problems described in IE Information Notice 83-75. The inspector's evaluation included discussions with the Reactor Engineer, the Operations Engineer, the Nuclear Training Representative and with licensed operators. The procedures reviewed included:

GP-2	Normal Plant Startup
GP-3	Normal Plant Shutdown
GP-4	Rapid Plant Shutdown to Hot Standby
GP-5	Power Operations
RE-201	Reactor Maneuvering Plan Approval
RE-202	Rod Worth Minimizer Loading and Approval
RE-501	Reactor Engineering Qualification Program
S-73	Reactor Manual control/Rod Worth Minimizer/ Rod Sequence Control System

No violations we·e identified.

9.0 Initial Main Turbine Roll Activities

The inspector reviewed the documents listed below and witnessed the initial main turbine sounding roll (100 rpm) and initial main turbine roll to rated speed (1800 rpm) to ascertain that the activities were performed within the licensed power constraints of NPF-27.

- SP-GP-006 "Main Turbine Initial Startup", Revision 1, dated April 5, 1985

- SP-GP-007 "Shutdown of Main Turbine During Low Power Testing", Revision 0, dated April 5, 1985

The inspector also held interviews with several licensee personnel including plant supervision, operators and test personnel. On April 10, 1985 at approximately 10:30 p.m. the licensee initiated the initial sounding roll of the turbine. This test requires accelerating the turbine to 100 rpm, shutting off the steam supply and listening during the coastdown for abnormal noise. The most sensitive APRM indicated reactor power at approximately 4.5% at initial conditions. The inspector witnessed portions of the shell warming and chest warming activities which preceded the initial sounding roll and no unacceptable conditions were noted. The inspector witnessed training in the overall turbine roll activities being given to plant supervision, operators and plant personnel as well as detailed briefings being provided to personnel directly involved in directing and performing the initial sounding roll. No unacceptable plant conditions were noted during the performance of the test and review of post test transient results also identified no unacceptable results. Approximately 13.5% bypass valve movement was required.

During the shell warming activities, the licensee noticed an increase in the reactor water conductivity. Licensee actions recovered from the conductivity increase transient. This increase was apparently due to the protective coating applied to the internal surfaces of the turbine. Chemistry technical specification limits were not exceeded. Precautions were being taken by the licensee chemists as a result of the conditions identified during the shell warming and were monitoring chemistry limits during the initial sounding roll and subsequent roll to rated.

Turbine roll activities were under the command of the Plant Superintendent. Quality Assurance personnel were also monitoring licensee performance.

On April 11, 1985 at approximately 11:18 a.m. the licensee initiated the main turbine roll to rated speed (1800 rpm). The most sensitive APRM indicated steady state power at approximately 4.75%. No control rod movement or recirculation pump flow increases were made during the initial roll to rated The turbine bypass valve was approximately 92% open prior to turbine operation and approximately 60% open when the main turbine reached rated speed at approximately 12:13 p.m. Due to problems with turbine bearing vibration indications, the turbine was tripped from a no load on the generator condition at 12:42 p.m. No unacceptable plant conditions were noted during the turbine start or turbine trip.

Prior to the roll of the main turbine, the licensee reviewed results from the sounding roll and developed limits for suspending testing activities. The Plant Superintendent and the lead GE representative concurrently authorized proceeding with the initial turbine roll to rated speed after review of these results.

Subsequently, the licensee successfully operated the main turbine and generator for 1 hour, 48 minutes on 4/13/85 and for approximately 24 hours on 4/15-16/85. Generator output during these operations varied from 10 to 20 MW electric.

No violations were identified.

10.0 Review of Special and Routine Reports

10.1 Review of Licensee Event Reports (LERs)

The inspector reviewed the licensee event reports (LERs) listed below to determine if the information provided was accurate and submitted in a timely manner; if the event cause was properly identified and corrective actions were appropriate; if the report described a potentially generic issue; and if the report satisfied the licensee's reportability requirements. Those event reports annotated with an asterisk (*) were specifically followed to verify the implementation of corrective action.

10.1.1 The following reports were found to be acceptable:

LER No.	Event Date	Description
85-08	1/12/85	Inadvertent engineered safety features isolations due to a blown fuse
85-09	1/12/85	Spurious isolation of the HPCI steam supply inboard isolation valve
85-16	1/22/85	Inadvertent HPCI steam supply isolation
85-22	1/30/85	Main steam isolation valve leakage control system found inoperable
85-24	2/8/85	Loss of 1B reactor protection system uninterruptible power supply
85-25	2/11/85	Spurious reactor water cleanup isolation
85-26	2/12/85	Loss of the 1A reactor protection system uninterruptible power supply
85-27	2/25/85	Spurious reactor water cleanup isolation
*85-28	3/1/85	Fire seals in the diesel generator enclosure were not installed (Section 10.1.4)
85-29 - 3/1/85 85-30 - 3/3/85 85-31 - 3/14/85	--	Inadvertent control room HVAC isolation due to broken tapes in the chlorine detectors

85-32	3/14/85	Inoperable fire damper
*85-34	3/22/85	Inadequate amount of sodium pentaborate in the standby liquid control tanks (Section 6.1)
85-35	3/23/85	Inadvertent isolation of reactor water cleanup system outboard isolation valve

10.1.2 The following reports were found to be lacking a documented analysis describing previous similar occurrences. The inspector requested the licensee consider supplementing these reports to include a review for previous occurrences. The licensee's actions will be reviewed in a future inspection (50-352/85-16-04).

LER No.	Event Date	Description
85-10	1/12/85	Isolation of the reactor water cleanup system
85-13	1/17/85	Failure to comply with technical specification requirements regarding HPCI instrumentation operability
85-14	1/18/85	Inoperable scram discharge volume level switch
85-15	1/21/85	Failure to establish fire watches as required by technical specifications
85-18	1/26/85	Reactor enclosure HVAC isolation due to technician error
85-19	1/29/85	Inoperable HPCI room ventilation differential temperature detector
85-23	2/5/85	Reactor enclosure HVAC isolation due to a failed compartment exhaust fan

10.1.3 LER 85-21

In this LER, the licensee described a full scram which occurred during low power startup testing on 1/31/85. The details of this event were described in NRC Inspection Report 50-352/85-11. As indicated in the inspection report, the event involved a reactor scram caused by an operator incorrectly returning a jet pump developed head instrument to service. During the event, the operators noticed that 34 of the 185 control rods did not have a full in indication on the full core display, although other indications existed that showed the rods were full in. Further, during the event, the reactor coolant system cooldown rate limit of 100 degrees F per hour was approached because of the small amount of decay heat available from the core at the time of the scram as compared to the existing steam loads.

The inspector noted that LER 85-21, issued for this event, described only the scram, its causes and corrective actions. The report was silent regarding the problems encountered with RCS cooldown rates or control rod position indications. Therefore, the inspector informed the licensee that the LER appeared to be incomplete because it failed to address these latter two problems. The inspector requested that the licensee consider revising or supplementing the LER to provide descriptions and corrective actions regarding RCS cooldown rates and control rod position indications. The inspector will follow the licensee's actions in this regard (50-352/85-16-05).

10.1.4 LER 85-28

The licensee discovered fire barriers containing inadequately sealed conduits between the diesel generator enclosures B, C and D and the service water pipe tunnel. The licensee explained that the reason for the unsealed conduits was that the design drawings indicating fire zones were not clear for the associated plant areas. As an interim compensatory measure, the licensee posted an hourly fire watch in accordance with Technical Specification 3.7.7.a. As a permanent fix, the licensee sealed the improperly sealed conduits. These actions were verified by the inspector. To prevent recurrence, the licensee committed to review the design drawings, provide clarification where necessary, and verify the "as-built" conditions.

The actions taken by the licensee in this area were found to be adequate.

10.2 Special Report on the Inoperability of a Seismic Monitor

In a letter dated 3/18/85, the licensee filed the special report required by Technical Specification 3.3.7.2 for an inoperable seismic monitor located at the top of the reactor vessel head. This monitor, designated XR-VA-151, became inoperable as a result of it overheating. The monitor overheated during low power testing partly because of missing mirror insulation between the vessel and the monitor and was discovered during an investigation of a problem with a startup test instrument.

As corrective action, the licensee replaced the seismic monitor and changed the insulation configuration. The inspector reviewed maintenance request forms 8503171 and 8503137 which replaced the monitor and its insulation respectively, along with MDCP0441 which addressed the new insulation configuration.

The inspector had no further questions.

10.3 Monthly Report

The inspector reviewed the Monthly Report for February and March, 1985 and found no discrepancies.

No violations were identified.

10.4 Licensee's Response to NRC Region I's Concerns Regarding Personnel Errors

The inspector reviewed the licensee's letter of April 2, 1985 regarding reportable events at the Limerick Generating Station. The subject of reportable events and personnel errors was presented as a NRC concern in Inspection Report 50-352/84-65, which was forwarded to the licensee on January 11, 1985. The licensee provided an interim response on February 11, 1985 and met with Region I management to discuss corrective measures on February 22, 1985 as documented in Inspection Report 50-352/85-11.

The licensee's April 2, 1985 letter describes the ongoing corrective action program and the initial results which suggest that reportable personnel errors have decreased in frequency since program inception. Based on an independent review of the licensee's program and an evaluation of recent LERs, it appears that the program has been effective at reducing personnel related reportable events. The NRC will continue to monitor licensee performance in this area.

No deficiencies were identified.

11.0 Monthly Surveillance Observations

The inspector observed and reviewed portions of surveillance test ST-7-022-353-0, Halon Inventory, to verify that the test had been properly approved by shift supervision, the technician performing the test was knowledgeable regarding the test, approved procedures were being used and test instrumentation was properly calibrated.

No violations were identified.

12.0 Maintenance Observations

The inspector periodically reviewed the status of selected maintenance activities to verify compliance with the station's administrative procedures and to assess the technical adequacy of the repair technique. During this period, the inspector witnessed work under MRF 8503334-03337 on the D11, 12, 13 and 14 emergency diesel generators in which the exhaust systems were being modified per MDCP 0416 to eliminate the problems which had been encountered with diesel exhaust gases entering the reactor enclosure through the normal HVAC system.

The inspector reviewed maintenance activities on the 1A reactor feed pump. Following the detection of high vibration on the A reactor feed pump on 2/28/85, the licensee issued MRF 8502779 to disassemble, inspect and repair the pump. Upon disassembly, damage to the impeller and to the pump casing was observed. Two pieces of the impeller had broken away and were transported within the system. Additionally, two other large cracks were observed on the impeller where the vanes interacted to the impeller rings. In the pump casing, there was evidence of battering and raised metal, indicative of the pieces of the impeller impacting it.

The licensee removed the identical pieces from a Unit 2 feed pump, machined them and installed them in the Unit 1 pump. The Unit 1 failed components were shipped offsite for metallurgical examination. The licensee further inspected portions of the feedwater system to retrieve the broken parts and developed an examination plan to be applied to the other Unit 1 reactor feed pumps.

No violations were identified.

13.0 Exit Meeting

The NRC resident inspector discussed the issues and findings in this report throughout the inspection period and at an exit meeting held with Messrs. J. Corcoran and G. Leitch on April 30, 1985. At this meeting the representatives of the licensee indicated that the items discussed in this report did not involve proprietary information. No written material was provided to the licenseee during this period.