U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-354/86-30

Docket 50-354

License NPF-50

Licensee: Public Service Electric and Gas Company

Facility: Hope Creek Generating Station

Conducted: June 10 - July 14, 1986

Inspectors: R. W. Borchardt, Senior Resident Inspector
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Approved: L. Norrholm, Chief, Projects Section 2B 7/29/86 Date

Inspection Summary:
Inspection on June 10, 1986 - July 14, 1986 (Inspection Report Number 50-354/86-30)

Areas Inspected: Routine onsite resident inspection of the following areas: followup on outstanding inspection items, operational safety verification, surveillance testing, maintenance activities, engineered safety feature (ESF) system walkdown, preoperational/startup testing, licensee event report followup, evaluation of spurious ESF actuations, corrective action program, Electrical, Instrumentation and Control Systems Branch visit, NRC Commissioner's visit, and main steam isolation valve spring inspection. This inspection involved 353 hours by the resident and project inspectors.

Results: A large percentage of inspection effort during this report period was directed towards the preparation for, and performance of initial criticality operations. These activities were generally well controlled and coordinated with a consistent emphasis on safety. Two violations were also identified during the report period.

First, failure to have an effective program for tracking system operability resulted in a violation of Technical Specifications due to the loss of the auto-swap capability of the suction flow path for RCIC. Although this problem was self identified, the violation was issued due to the significance of the event.

Second, failure to take timely corrective actions for Quality Assurance (QA) identified discrepancies has been cited as a violation of 10 CFR Appendix B.

In the past, inspectors have identified discrepancies similar to those identified by QA and have allowed the internal corrective action program to resolve these problems. However, review of your corrective action program indicates that the organization as a whole is not always responding adequately to self identified deficiencies. A large percentage of individual department responses to QA action requests are submitted well past the response due dates with no extension requested.

DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with members of the licensee management and staff and various contractor personnel as necessary to support inspection activity.

2. Followup on Outstanding Inspection Items

2.1 Violations

(Closed) Violation (86-20-01); Filtration, Recirculation and Ventilation System Operability. (See below)

(Closed) Violation (86-20-02); Standby Liquid Control System Surveillance Testing.

During initial fuel load activities the inspector identified two violations which resulted from making the Filtration, Recirculation and Ventilation system (FRVS) inoperable and failing to perform required surveillance testing on the Standby Liquid Control system (SLC). The licensee's response to these violations was provided to the NRC in a letter dated June 19, 1986. The control room console checklist (OP-AP.ZZ-107) and the Operation's Department Surveillance Log (OP-DL.ZZ-026) were revised in an effort to prevent recurrence of these violations. The inspector has no further questions at this time and will continue to review the licensee's compliance with Technical Specifications on a routine basis.

2.2 Inspector Follow Items

(Closed) Inspector Follow Item (86-02-03); Planning and Scheduling Administrative Procedures. The inspector verified that the Plan and Scheduling Department administrative procedures have been written and approved. The following procedures were specifically reviewed:

- PL-AP.ZZ-002(Q) Station Planning Department Organization
- PL-AP.ZZ-101(Q) Unscheduled Outage Planning
- PL-WP.ZZ-003(Q) Scheduling Input to PREMIS
- PL-WP.ZZ-002(Q) Retest Package Preparation
- PL-WP.ZZ-001(Q) Planning and Scheduling of Work Orders

The inspector has no further questions.

(Closed) Inspector Follow Item (86-20-01); Investigation of Spurious LOCA Signals. During the time period between fuel load and initial

criticality the licensee experienced a number of single channel Loss of Coolant Accident (LOCA) signals. Special Test Procedure 86-05-29-112-5-1 was performed to determine the cause of these spurious signals and the results of this procedure are discussed in paragraph 9 of this report.

(Closed) Inspector Follow Item (85-53-01); Management Coordination and Awareness of EDO's Priorities

(Closed) Inspector Follow Item (85-53-02); TSC Discussion of Emergency Power Requirements

(Closed) Inspector Follow Item (85-53-03); Radio Communicator Use for Other Purposes

(Closed) Inspector Follow Item (85-53-04); Confusion About Tagging Procedure use in Emergency

(Closed) Inspector Follow Item (85-53-05); Rad Protection Personnel Tracking Difficulties

(Closed) Inspector Follow Item (85-53-08); Handling of Iodine Sample by Environmental Team

(Closed) Inspector Follow Item (85-53-10); EOF Functions Duplicated

(Closed) Inspector Follow Item (85-53-11); Minimal Decision Making by Rad Safety Manager

On October 28-30, 1985, an NRC inspection team observed the licensee's annual full scale emergency exercise (Delaware only). No significant deficiencies were identified; however, as a result of these observations, the items listed above were identified as areas which deserved the licensee's evaluation and possible corrective action. The next full scale emergency exercise will be observed by the inspector and the results of the October 1985 exercise will be reviewed prior to its start. The inspector will then evaluate the licensee's corrective actions resulting from the October 1985 exercise. For administrative purposes the items listed above are closed, however the inspector will review the October 1985 exercise results prior to the next full scale exercise and evaluate the licensee's corrective actions (86-30-01).

2.3 Unresolved Items

(Closed) Unresolved Item (86-10-03); Retest of Acoustic Monitors. Each reactor pressure vessel safety relief valve (SRV) has an acoustic monitor mounted on the discharge pipe to the torus which will give the operators indication of an open SRV. Because of problems identified during the preoperational test program this open item was written to verify that all acoustic monitors were installed and

operable prior to drywell closure and initial criticality. The inspector reviewed completed work order 86-06-17-022-4 which verified operability. The inspector also conducted an independent tour of the drywell and found the acoustic monitors to be properly mounted. This item is closed.

2.4 Construction Deficiency Report (CDR)

(Closed) Construction Deficiency Report (86-00-03); Diesel Air Start System. The subject CDR identified inadequate venting of the diesel rack boost cylinder after start signal termination on Colt-Pielstick PC-2 engines. This causes the boost cylinder to fight the governor and creates a potential overspeed condition and resultant overspeed trip.

To correct this deficiency, the licensee has completed installation of Colt-Pielstick recommended alteration to positively vent the rack boost cylinder promptly after start signal termination. All completed piping modifications have been leak tested. All diesel engines have subsequently passed surveillance testing.

The inspector reviewed the work packages, questioned the system engineer, and conducted an in-plant walkdown of all diesel air start modifications. No problems were identified. This item is closed.

2.5 IE Bulletins, Circulars, and Notices

(Closed) IE Bulletin (86-BU-01); Minimum Flow Logic Problems that could Disable RHR Pumps. This bulletin concerns the potential loss of all RHR pumps due to a single failure of the minimum flow logic. A minimum flow logic failure could cause all RHR minimum flow bypass valves to shut and result in all RHR pumps running dead headed with potential for pump damage in several minutes.

The inspector reviewed the licensee's response, FSAR, RHR piping and instrument diagrams, and conducted an in-plant inspection. The licensee's RHR system consists of four RHR pumps, each with its own minimum flow line, bypass valve, flow element, and flow transmitter. These four RHR channels are physically, electrically, and logically independent. A single failure in any one RHR minimum flow path, including the bypass valve, will disable only that one RHR loop. This item is closed.

3. Operational Safety Verification

3.1 Documents Reviewed

- Selected Operator's Logs
- Senior Shift Supervisor's Log
- Jumper Log
- Radioactive Waste Release Permits (liquid & gaseous)

- Selected Radiation Work Permits (RWP)
- Selected Chemistry Logs
- Selected Tagouts
- Health Physics Watch Log

3.2 The inspectors periodically toured the plant during regular and backshift periods. These tours included the control room, Reactor, Auxiliary, Turbine and Service Water buildings, and the drywell (when access is possible). During the inspection activities, discussions were held with operators, technicians (HP & I&C), mechanics, supervisors, and plant management. The purpose of the inspection was to affirm the licensee's commitments and compliance with 10 CFR, Technical Specifications, and Station Procedures.

(1) On a daily basis, particular attention was directed to the following areas:

- Instrumentation and recorder traces for abnormalities;
- Adherence to LCO's directly observable from the control room;
- Proper control room shift manning and access control;
- Verification of the status of control room annunciators that are in alarm;
- Proper use of procedures;
- Review of Logs to obtain plant conditions; and,
- Verification of surveillance testing for timely completion.

(2) On a weekly basis, the inspectors confirmed the operability of selected ESF trains by:

- Verifying that accessible valves in the flow path were in the correct positions;
- Verifying that power supplies and breakers were in the correct positions;
- Visually inspecting major components for leakage, lubrication, vibration, cooling water supply, and general operating conditions; and,
- Visually inspecting instrumentation, where possible, for proper operability.

(3) On a biweekly basis, the inspectors:

- Verified the correct application of a tagout to a safety-related system;

- Observed a shift turnover;

- Reviewed the sampling program including the liquid and gaseous effluents;

- Verified that radiation protection controls were properly established;

- Verified that the physical security plan was being implemented;

- Reviewed licensee-identified problem areas; and,

- Verified selected portions of containment isolation lineup.

3.3 Inspector Comments/Findings:

The unit entered this report period in Mode 4 with the reactor shutdown, coolant temperature less than 200 degrees F, conducting surveillance in preparation for initial criticality.

In the previous inspection report period on June 7, 1986, the "A" Standby Liquid Control (SLC) system inadvertently actuated for seventeen seconds. The SLC pump started, squib valve fired and reactor water cleanup system isolated coincident with the manual start of the "A" emergency diesel generator. Boron was injected into the core spray system, but the SLC pump was stopped prior to boron injection to the reactor vessel. The core spray lines were flushed with reactor vessel water through the fired squib valve into disposal drums. Extensive review and testing has not identified the cause. The licensee mailed the Bailey 862 Solid State Logic modules associated with SLC to Bailey for additional testing. The inspector will follow the licensee's efforts to identify the cause of this event. The licensee has committed to submit a supplemental LER if the cause is determined.

Initial criticality was achieved at 11:18 p.m. on June 28, and was followed by a full core shutdown margin demonstration and a source range non-saturation demonstration. Region I inspectors provided 24 hour/day coverage of initial criticality activities and will have expanded coverage for selected activities throughout the low power test program. For additional information on initial criticality, refer to paragraph 7 of this report.

At 1:12 p.m. on June 29, 1986, the reactor scrammed on high IRM flux. The reactor was in a non-coincidence RPS logic mode at the time (shorting links removed). After having just completed the necessary tests to install the shorting links, the reactor was placed in a sub-critical condition. Due to decreasing neutron counts, the operator was downranging IRMs. The operator was attempting to downrange IRM "B" and selected IRM "D". IRM "D" exceeded the RPS trip point and a reactor scram occurred. All rods inserted. A Region I based

startup inspector observed licensee's actions. The licensee reinstalled the shorting links, restarted the reactor and resumed the startup program testing.

At 4:51 p.m. on June 30, 1986, the licensee manually scrammed the reactor to repair the Reactor Manual Control System (RMCS). The RMCS had been inserting a continuous rod motion block for unknown reasons. The licensee and General Electric representatives diagnosed the problem as a failed RMCS power supply. The licensee completed RMCS power supply replacement and unit went critical at 6:42 p.m. on July 1.

On July 3, 1986, the plant experienced two separate emergency core cooling system (ECCS) actuations which a subsequent investigation revealed to be caused by the improper calibration of a reactor vessel level transmitter. The transmitter being calibrated (3682 B) was a post accident monitoring device that shares common instrumentation piping with the Loss of Coolant Accident (LOCA) level transmitters. On two separate occasions, while returning the 3682 B transmitter to service, the I&C technician apparently operated the instrument isolation valves too quickly and caused a perturbation on the common sensing lines. This perturbation caused the "B" LOCA level transmitters to trip, resulting in the "B" core spray, "B" low pressure coolant injection system, and the "B" diesel generator to start. All systems operated properly and the plant operators secured the pumps and diesel. The inspector attended the post event fact finding meeting at which it was determined that a number of factors contributed to the inadvertent actuation of the emergency core cooling systems and the "B" diesel generator.

- It was not recognized, that although the 3682 B transmitter was not a safety-related instrument nor was its calibration required by Technical Specification (TS), it does share common reference and variable legs with safety related ECCS instruments.

- A generic calibration procedure was used by the I&C technician which allowed him to perform the calibration dry (transmitter drained) instead of having the transmitter full as would normally be desired. (TS required calibrations use instrument specific procedures.)

- Because the calibration was not being done to satisfy a TS requirement, the technician chosen for the job was not one of the specially trained surveillance test technicians. These "ST" technicians have received special instructions on the precautions of working on ECCS instrumentation.

Nuclear System Engineering and Instrument and Controls conducted a review of P&ID M-42 and identified approximately eleven additional Non-Technical Specification instruments that share common sensing lines with ECCS instrumentation. All work was stopped on the

identified instruments until specific procedures were written and approved. Once a procedure was available, calibration activities could commence by an appropriately qualified technician.

At 1:28 p.m. on July 4, 1986, the reactor scrammed during heatup for power ascension testing. The scram occurred when an APRM channel "E" high upscale neutron trip was coupled with a half scram manually inserted due to narrow range level perturbations. The shift carried out the scram procedure and the plant was placed in a shutdown condition. The APRM channel "E" high upscale neutron trip was attributed to a failed LPRM which was subsequently bypassed. The reactor was taken critical at 12:26 a.m. on July 7.

At 6:30 p.m. on July 6, 1986, an alert was declared when tampering was considered a possible cause for the initiation of the Diesel Generator (DG) Building Fire Suppression System. An air operated water deluge valve opened and the electric fire pump started, pressurizing the sprinkler system and fire hoses in the D/G area. No water was actually released since the fusible links remained intact. The fusible links are designed to activate under the high heat conditions of a fire. Subsequent investigation revealed that an area detector (heat sensor) malfunction caused the system initiation and that tampering was not the cause. The alert was terminated at 7:30 p.m. on July 6.

At 5:32 p.m. on July 7, 1986, the "A" control room ventilation intake duct radiation monitor spiked upscale causing the "A" train of control room ventilation to isolate. The "B" train of control room ventilation was in service and was not affected. All equipment responded as expected, the "A" monitor was verified to be faulty and was placed in the tripped condition in accordance with Technical Specifications.

At 2:22 p.m. on July 12, 1986, the licensee inserted a manual scram when both "C" and "D" steam flow transmitters in main steam line "B" sensed high steam flow and shut all MSIVs. HPCI and RCIC were not available to bleed steam to control pressure as the combined HPCI and RCIC full flow test valve to the condensate storage tank was tagged shut for maintenance. The high steam flow indication was attributed to transmitter drift. Both "C" and "D" transmitters were replaced and the reactor taken critical at 10:27 p.m. on July 13 to continue low power testing.

At 9:49 a.m. on July 14, 1986, an erroneous level-1 and level-2 channel "A" LOCA signal was received. At the end of the report period, the licensee had not yet identified the root cause. All systems responded as expected for the plant conditions (Mode 2, reactor power .1%, temperature 360 degrees F, pressure 140 psig). The "A" LPCI and HPCI pumps started but were manually secured prior to water injection into the vessel. "A" CS pump injected approximately 6000 gallons into the reactor vessel. The inspector will review this event when the LER is submitted.

On July 14, 1986, the licensee discovered RCIC was inoperable while attempting to perform the RCIC condensate storage tank (CST) suction auto-swap to suppression pool functional test. An investigation determined the CST level transmitters were disconnected on June 27, 1986, for a design change and were out of service since that time. The conditions for the RCIC LCO include the capability of automatically taking a suction from the suppression pool and transferring the water to the reactor pressure vessel. Technical Specification 3.7.4 also requires RCIC operable in operational condition 1, 2, and 3 with steam dome pressure greater than 150 psig. On July 9, 1986, at 1:50 a.m. while in operational condition 2, reactor pressure was raised to 155 psig and remained greater than 150 psig until a reactor scram occurred at 2:22 a.m. on July 12, 1986. Entry into such specified conditions shall not be made unless the conditions of the LCO are met as required by Technical Specification 3.0.4.

Prior to this incident the Control Room Action Statement Log was only utilized to track equipment required to be operable in the present mode. On June 27, RCIC was not entered in the Action Statement Log because RCIC was not required to be operable at the time the Design Change Package work order was approved by Operations to start work. As immediate corrective action, the licensee has instructed all SROs to utilize the Action Statement Log to track equipment in all operating modes. Although the licensee identified this problem and has implemented immediate correction action, the inspector informed the licensee that the lack of an effective program to track system operability resulted in a violation of Technical Specifications (86-30-02).

4. Surveillance Testing

During this inspection period the inspector performed detailed technical procedure reviews, reviewed in-progress surveillance testing as well as completed surveillance packages. The inspector also verified that the surveillances were performed in accordance with licensee approved procedures and NRC regulations. The inspector also verified that the instruments used were within calibration tolerances and that qualified technicians performed the surveillances.

The following surveillances were reviewed, with portions witnessed by the inspector:

- IC-CC.SE-029, OP-ST.SE-004, SRM Channel Functional Test

- OP-ST.BD-003, RCIC System Functional Test

In addition, surveillance activities supporting initial criticality were also observed as discussed in paragraph 7 of this report.

No violations were identified.

5. Maintenance Activities

During this inspection period the inspector observed selected maintenance activities on safety related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. The following activities were reviewed:

Work Order	Description
86-07-02-010-2	Troubleshooting/Repair of SLCS tank level transmitters
86-06-09-112-0	Repair of MSIV
86-06-09-125-1	Removal of hanger/interference

No violations were identified.

6. Engineered Safety Feature (ESF) System Walkdown

The inspectors verified the operability of the selected ESF systems by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration. This ESF system walkdown was also conducted to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. The control rod drive (CRD), core spray loop A, and the standby liquid control (SLC) system were inspected.

During the walkdown of the CRD system the inspector observed inadequate channel separation between two back-up scram pilot electrical cables. The inspector informed QA of this condition and work order 86-07-03-017-5 was written. The inspector reviewed this work order and had no further questions.

During the walkdown verification of the SLC system, a number of discrepancies were identified as follows:

- Valve 1-BH-V024 was closed (normally locked-open)
- Valves 1-BH-V006 and 7 did not have locking devices installed; and,
- Valves 1-BH-V062, 63, 64 and 65 were not listed on the valve lineup procedure (OP-SO.BH-001(Q))

Valve 1-BH-V024 is a normally locked-open valve in the test tank supply line to the "A" SLC pump. This test line is normally isolated by a locked-closed valve (1-BH-V053) at the discharge of the test tank. Therefore 1-BH-V024 is not in the normal suction flow path to the pump and would not have prevented system operation. The remaining discrepancies

also would not have prevented system operation, because the valves were in their required positions. However, these items indicated that the Tagging Request Information System (TRIS) data base was not being maintained current.

TRIS is used to conduct system lineups and system restoration following maintenance and surveillance activities. Full system lineups are normally conducted prior to startup following refueling or when directed by management. The SLC system lineup had been conducted prior to fuel load and had been verified (without alignment discrepancies) during NRC Inspection 50-354/86-20.

On June 7, 1986, an inadvertent SLC actuation occurred (reference NRC Inspection Report 50-354/86-26). This resulted in a series of flushing operations to remove the borated solution from the SLC lines, which required a number of valve manipulations to complete. Following this activity, the system was restored to normal alignment using the TRIS system "off normal" report. The items identified above were not included in the "off normal" report and therefore were not properly restored.

When this was identified to the licensee, a full SLC system lineup was conducted and the discrepancies corrected. The licensee determined that the flushing evolution was not a "normal" type of maintenance activity in which TRIS, through maintenance tagging requests, would be capable of maintaining current valve position information. Therefore, Operations Department management should have required a full system lineup for proper restoration following the flushing. In addition, the licensee conducted a lineup verification of the diesel generator auxiliaries satisfactorily. This system was selected based on the number and types of maintenance activities that had occurred since a full system lineup was last completed. Based on the licensee's immediate corrective actions, the fact that the SLC was not yet required to be operable, and that the discrepancies identified would not have prevented system operation, the inspector had no further concerns at this time.

During the walkdown verification of the "A" Core Spray subsystem, the inspector noted that valves 1-BE-V117 and 118 were closed but not locked. Neither the licensee's lineup procedure nor the P&ID (M-52-1) required these valves to be locked, therefore they were lined up in accordance with procedures. However, these valves are single manual isolation valves (one inch or less) that are part of the primary containment boundary. It was later determined that these valves are typical vent, drain and test connection valves that are located upstream of the outboard containment isolation valves that are listed in the plant Technical Specifications. There are approximately 140 similar valves.

These vent, drain and test connection isolation valves exist in three configurations as follows:

- single manual valve with a threaded cap

- two series manual valves with a threaded cap

- two series manual valves without a cap.

10 CFR 50 Appendix A General Design Criteria (GDC) require that manual containment isolation valves be locked closed. In addition, those manual isolation valves listed in the Technical Specifications are also subject to periodic surveillance to verify that they are locked closed to assure containment integrity is maintained. The licensee did not list these valves as containment isolation valves in either the FSAR or the Technical Specifications. Based on a conversation with NRR, the inspector found that listing of vent, drain and test connections in the FSAR and Technical Specifications as containment isolation valves was not necessary. However, these valves are considered to be part of the containment boundary and should meet the GDC. In addition, to assure containment integrity periodic surveillance of these valves should also be conducted. The licensee is currently developing the necessary administrative controls for the vent, drain and test connection valves to meet the GDC for containment integrity. Resolution of this concern will be detailed in the next monthly inspection report.

No violations were identified.

7. Preoperational/Startup Testing

7.1 The licensee completed final preparations and took the reactor critical at 11:18 p.m. on June 28.

7.2 Initial criticality was followed by a full core shutdown margin demonstration and a source range non-saturation demonstration. Region I inspectors provided 24 hour/day coverage of initial criticality activities and will have expanded coverage for selected activities throughout the low power test program. The inspectors reviewed and witnessed the following procedures:

1) Full Core Shutdown Margin Demonstration TE-SU.ZZ-041(Q) Revision 4

2) Shutdown Margin Demonstration RE-ST.ZZ-007(Q) Revision 2

3) Source Range Monitor Response to Rod Withdrawal TE-SU.SE-062(Q) Revision 2

4) Source Range Monitor Non-Saturation Demonstration TE-SU.SE-064(Q) Revision 1

5) Source Range Monitor/Intermediate Range Monitor Overlap Verification TE-SU.SE-101(Q) Revision 3

6) Startup From Cold Shutdown to Rated Power OP-IO.ZZ-003(Q)

The inspectors conducted a temporary modification audit including an applicable safety evaluation review. Additional inspector coverage of initial criticality is discussed in Inspection Report 86-32.

No violations were identified.

8. Licensee Event Report Followup

The licensee submitted the following event reports during the inspection period. All of the reports were reviewed for accuracy and timely submission. Certain designated reports were followed up by the inspector to review implementation of corrective action. These are indicated by an asterisk below.

*	LER 86-012	Control Room Emergency Filtration Actuation Resulting from Equipment Failure
	LER 86-013	Inadvertent Isolation of RWCU System During Surveillance Testing
*	LER 86-014	"D" Channel Engineered Safety Feature Actuation
*	LER 86-015	Spurious "A" Channel LOCA Initiation
*	LER 86-016	Control Room Emergency Filtration Initiation
*	LER 86-017	Inadvertent Actuation of the "A" Control Room Emergency Filter Unit During Troubleshooting
*	LER 86-019	"D" Channel Engineered Safety Feature Actuation
*	LER 86-020	"D" Channel Engineered Safety Feature Actuation
*	LER 86-021	"D" Channel Engineered Safety Feature Actuation
	LER 86-022	Inadvertent Isolation of RWCU System
*	LER 86-023	"B" Channel Engineered Safety Feature Actuation
	LER 86-024	Inadvertent "D" Channel LOCA Signal During Surveillance Testing
	LER 86-025	Control Room Emergency Filtration Chiller Actuation Due to Power Supply Trip
	LER 86-026	Automatic Start of "A" Control Room Chiller
	LER 86-027	Installation of Combustible Material in the Traveling Screen Motor Room
*	LER 86-028	Inadvertent Actuation of "A" Channel Standby Liquid Control

LERs 86-012 and 86-016 both detail automatic actuations of the Control Room Emergency Filtration System. The cause of both events was a faulty power supply to a detector in the Control Room Radiation Monitoring system. The power supply was recalibrated and the system restored to normal. LER 86-017 also details an automatic actuation of the Control Room Emergency Filtration system. This event occurred as a result of troubleshooting efforts to identify the cause of the event reported in LER 86-016. No further similar events have occurred; however, the licensee is continuing to monitor the system to identify any further corrective actions. Although the immediate corrective actions appear to have been adequate, the inspector will followup on the licensee's monitoring efforts during a future inspection to determine if any changes to the LERs are required.

LERs 86-014, 86-019, 86-020, 86-021 and 86-023 describe spurious Engineered Safety Feature actuations. These events are all related in that the cause appears to be a pressure transient in the common sensor lines. Due to the number of spurious level related ESF actuations, the licensee formed a task team to research the problem and determine corrective actions. These actions are outlined in LER 86-019 and a review of the licensee's efforts are detailed in paragraph 9 of this report. For certain events (86-020 and 86-021), the licensee has determined the most probable cause was an induced pressure transient by test personnel performing maintenance on the common sensor lines (transmitter replacement and valving operations).

LER 86-015 describes a spurious actuation of the "A" Channel Engineered Safety Features (LOCA initiation). The root cause of this event was the improper opening of an instrument root valve on the "A" channel reference leg. Details of this event are described in paragraph 3.3 of NRC Inspection Report 50-354/86-26. The licensee's immediate corrective actions included walkdowns of sensing lines to find other mispositioned valves and also the implementation of the Instrument Root Valve Lineup procedure. The inspector reviewed these actions and has no further questions at this time. However, the inspector will follow the licensee's long term corrective action to place these types of valves in the TRIS computer for better administrative control of proper alignment.

LER 86-028 describes an actuation of the "A" channel of Standby Liquid Control. Details of this event are discussed in paragraph 3.3 of this report and in NRC Inspection Report 50-354/86-26.

9. Evaluation of Spurious ESF Actuations

Since receipt of the low power operating license on April 11, 1986, the licensee has experienced five Loss of Coolant Accident (LOCA)/Engineered Safety Feature (ESF) Actuations for which a root cause could not be determined. A listing of the event dates and the affected channel is shown below:

Event	PSE&G Incident Report No.	Date	Description
1	86-041	4/20/86	ESF Actuation on B Channel
2	86-048	4/26/86	ESF Actuation on A Channel
3	86-057	5/6/86	ESF Actuation on D Channel
4	86-064	5/13/86	ESF Actuation on D Channel
5	86-065	5/13/86	ESF Actuation on D Channel

The licensee attempted to determine a root cause, however it was obvious from the event reviews that plant conditions did not warrant an ESF actuation since reactor vessel level was steady and well above the low-low level setpoint.

Three possible root causes were proposed,

- a perturbation in common sensor lines of LOCA instrumentation,
- a perturbation in the common power supplies for LOCA instrumentation, and
- some type of reactor vessel transient.

Special Test Procedure 86-05-29-112-5-1 was developed and performed in an effort to examine these possible causes. The results of this test were reviewed and discussed with the licensee system engineers onsite and also at a management meeting at the NRC Region I offices on June 5, 1986. Through the process of elimination, the only feasible explanation for the ESF actuations was a perturbation in the common sensor lines of ESF/LOCA instrumentation (specifically reactor vessel level instruments). In an effort to prevent recurrence of similar events, the licensee committed to performing the following actions:

Prior to initial criticality

- Blow back instrument lines
- Install identification tags on LOCA/ECCS instrument sensor lines
- Install quick disconnects on LOCA/ECCS instruments
- Review incidents with all I&C Technicians

By July 15, 1986

- Complete installation of identification tags on RPS/NSSS instrument sensor lines

- Review LOCA/ECCS surveillance procedures

- Include instrument sensor valves in status log

By September 1, 1986

- Complete review of RPS/NSSS surveillance procedures

- Complete installation of cages around LOCA instrument racks

The inspector has verified that the initial criticality commitments have been satisfied and will followup on the remaining commitments in a future inspection (86-30-03).

10. Corrective Action Program

The inspector conducted a review and inspection of the licensee's program for the identification and resolution of problems that could have an impact on plant safety. The major focus was on the station Quality Assurance program's findings and the corrective action program. Quality Assurance Procedure QAP 7-1 "Corrective Action" describes the licensee's program for identification of deficiencies and ensuring that corrective actions have been adequately implemented. There are four methods of identifying these deficiencies. In order of increasing significance they are:

- Quality Action Request (QAR)

- Corrective Action Request (CAR)

- Management Action Request (MAR)

- Stop Work Order (SWO)

Since September, 1985, there have been 47 QAR's (including reissues), 18 CARs, 3 MARs and 0 SWOs issued. These action requests were found to be generally well thought out and frequently documenting concerns shared by the NRC.

The corrective action program appears to be working satisfactorily with the exception of the timeliness of the individual department's responses to the action requests. When an action request is issued by QA, the addressee is provided a "response due" date which may be as long as 25 working days from the date of issue but is also dependent upon the finding's significance. The addressee may request an extension to the response due date which must be approved by QA. Of the 68 action requests issued to date, approximately 47 of the responses were submitted to QA late. As can be seen from the following partial list of overdue responses, as of June 26, 1986, some are overdue by a significant period of time.

Deficiency Number	Response Due Date	Response Received	Time Overdue (Working Days)
HS-85-Q001-0	9/23/85	10/22/85	21
HS-85-Q006-0	1/22/86	2/5/86	10
HS-86-Q002-0	1/17/86	3/20/86	43
HS-86-Q005-0	2/10/86	3/20/86	27
HS-86-Q006-0	2/14/86	3/20/86	23
HS-86-Q007-0	2/14/86	3/20/86	23
HS-86-Q008-0	2/14/86	3/20/86	23
HS-86-Q009-0	2/19/86	3/20/86	21
HS-86-Q014-0	3/24/86	*	67+
HS-86-Q016-0	4/4/86	5/1/86	19
HS-86-Q019-0	4/15/86	5/28/86	30
HS-86-Q020-0	5/1/86	6/12/86	29
HS-86-Q027-0	5/9/86	6/26/86	33
HS-86-Q029-0	6/5/86	6/26/86	15
HS-86-Q030-0	6/6/86	6/23/86	11
HS-86-C004-1	3/17/86	3/27/86	8
HS-86-C009-0	4/4/86	6/4/86	42
HS-86-C010-0	4/13/86	5/9/86	20
HS-86-C012-0	5/12/86	*	32+
HS-86-C013-0	6/16/86	*	8+
HS-86-M003-0	5/15/86	5/28/86	8

*Not received as of June 26, 1986

Timely corrective action is required by both Appendix B to 10 CFR 50 and the licensee's own procedures. The failure to take prompt corrective action is a violation (86-30-04).

11. Electrical, Instrumentation and Control Systems Branch Visit

During the Electrical, Instrumentation and Control Systems branch visit at Hope Creek on September 24-26, 1985, a deficiency was identified with labeling remote shutdown station readout devices. Appropriate identification tags were not mounted at each remote shutdown station readout device for the following parameters: reactor pressure (690 A, E, J & N); reactor vessel level (621 - 691 A&A); suppression pool level indicator (P/C R609); and suppression pool temperature (L/C R604A). A subsequent telephone conversation between R. Lint of Bechtel, representing PSE&G, and J. Mauck of the NRC concluded that mounting appropriate tags could be deferred until up to six months after completion of fuel load. This item will remain open until the appropriate identification tags are mounted at each identified readout device (86-30-05).

12. NRC Commissioner's Visit

Commissioner Asselstine met with licensee management and toured the Hope Creek facility on June 30, 1986. The tour included the control room, turbine deck, refueling floor, drywell and the PSE&G Nuclear Training Center.

13. Main Steam Isolation Valve Spring Inspection

On June 6, 1986, Attwood & Morrill Co., Inc. informed the NRC that cracks had been observed in four external closing springs on Main Steam Isolation Valves (MSIV) at Detroit Edison's Enrico Fermi Unit 2. The cause was determined to be quench cracks developed during the manufacturing process. Attwood & Morrill was the supplier for the MSIVs at Hope Creek. Both Attwood & Morrill and General Electric (GE) provided recommended inspection programs which the licensee considered in developing their own position. GE's final recommendation and the inspection program accepted by the licensee was to visually inspect the accessible surfaces of all inner and outer springs for cracks or other indications. If any defects are identified the spring is to be replaced with a spring that had passed the 5% overload test. The licensee will also reinspect the springs at each refueling outage to assure no new indications/defects develop. The inspector reviewed QA surveillance report HC-86-175 which documents the visual inspection of the MSIV springs. No indications were observed, and the inspector has no further questions.

14. Exit Interview

The inspectors met with licensee and contractor personnel periodically and at the end of the inspection report to summarize the scope and findings of their inspection activities. Written material was not provided to the applicant during the exit.

Based on Region I review and discussions with the licensee, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.