U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-213/85-21

Docket No. 50-213

License No. DPR-61

Licensee: Connecticut Yankee Atomic Power Company
P. O. Box 270
Hartford, CT 06101

Facility: Haddam Neck Plant, Haddam, Connecticut

Inspection at: Haddam Neck Plant

Inspection conducted: October 16 - December 2, 1985

Inspectors: Paul D. Swetland, Senior Resident Inspector
Stephen Pindale, Resident Inspector

Approved by: E. C. McCabe 1/10/86
E. C. McCabe, Chief, Reactor Projects Section 3B Date

Summary:

Areas Inspected: This was a routine inspection of licensed activities involving 152 inspection-hours by two resident inspectors. The following activities were included in the inspection: plant operations, radiation protection, physical security, fire protection, plant modifications, maintenance and surveillance testing, plant procedures, follow-up on previous inspection findings, follow-up on IE Circulars and Information Notices, and follow-up on licensee events.

Results: Inspector review of plant activities generally identified satisfactory performance. Licensee response to two plant trips and an unplanned release of gaseous radioactivity was proper and oriented toward continued plant safety. However, instances of failure to fully comply with administrative control procedures was identified in several areas of licensed activities. These are detailed in Paragraphs 3,4,7 and 9 of this report. One of these, not changing surveillance procedures to incorporate a PORV design change (Detail 9.c), may be related to the adequacy of licensee corrective actions instituted as a result of the refueling cavity seal failure in August, 1984. Licensee action on previously open NRC findings was adequate to close five of these items (Details 4 and 5). One item remained open pending further licensee action and one item was changed to a violation involving inadequate corrective actions (Detail 4.6). New NRC open items were identified for review of licensee follow-up action related to the cycle 13 coastdown (Detail 2.2), the 1985 10 CFR 50.59 Report (Detail 2.4), instrumentation department training in Technical Specifications (Detail 3.2), satisfactory performance of the low pressure over-pressure relief system (Detail 6.2), control of waste gas system operation (Detail 6.3), and interaction between steam flow measurement channels (Detail 6.4).

TABLE OF CONTENTS

DETAILS

1. Summary of Facility Activities

At the start of the inspection period on October 16, 1985, the plant was operating at full power and continued to do so until October 27, 1985, when a load reduction was initiated to perform monthly turbine stop/throttle valve testing. The plant resumed full power operation following completion of the test and continued full power operation until the plant entered the cycle 13 End of Cycle/Coastdown operation on November 3, 1985. Reactor trips due to high main steam line flow occurred on November 10 and 21, 1985. The cause of the trips was attributed to spurious closure of a main steam line isolation valve and inter-channel interference during surveillance testing, respectively. Malfunction of one of two main feedwater pumps resulted in a power reduction to 60 percent power on November 25 and a plant shutdown on November 27 to repair the damaged feed pump. Power operations resumed in the coastdown mode on November 29, 1985, and continued through the end of the inspection period. The plant is scheduled to begin a refueling outage on January 4, 1986.

2. Review of Plant Operations

The inspector observed plant operation during regular tours of the following plant areas:

-- Control Room	-- Security Building
-- Primary Auxiliary Building	-- Fence Line (Protected Area)
-- Vital Switchgear Room	-- Yard Areas
-- Diesel Generator Rooms	-- Turbine Building
-- Control Point	-- Intake Structure and Pump Building

Control room instruments were observed for correlation between channels and for conformance with Technical Specification requirements. The inspector observed various alarm conditions which had been received and acknowledged. Operator awareness and response to these conditions were reviewed. Control room and shift manning were compared to regulatory requirements. Posting and control of radiation and high radiation areas was inspected. Compliance with Radiation Work Permits and use of appropriate personnel monitoring devices were checked. Plant housekeeping controls were observed, including control and storage of flammable material and other potential safety hazards. The inspector also examined the condition of various fire protection systems. During plant tours, logs and records were reviewed to determine if entries were properly made and communicated equipment status/deficiencies. These records included operating logs, turnover sheets, tag-out and jumper logs, process computer printouts, and Plant Information Reports. The inspector observed selected aspects of plant security including access control, physical barriers, and personnel monitoring.

2.1 During a review of licensee administrative control procedures at the Millstone site, NRC determined that these procedures specify Supervising Control Operator (SCO) duties and responsibilities which include direct-

ing the activities of licensed reactor operators. However, the procedures did not require the SCO to possess an NRC senior reactor operator (SRO) license as required by 10 CFR 50.54 (l). At Haddam Neck, SCOs do have SRO licenses. The inspector reviewed administrative control procedure (ACP) 1.0-3, Connecticut Yankee Organization, Responsibility and Authority, to determine if non-SRO licensed personnel are procedurally permitted to be SCOs at Haddam Neck. ACP 1.0-3 makes reference to the SCO position description, which details an expected qualification for the SCO position to be the possession of an NRC SRO license. The inspector discussed this topic with the Operations Supervisor who indicated SCOs are SRO licensed to meet the shift staffing requirement (10 CFR 50.54(m)) for two SRO licenses on each shift. The inspector had no further questions in this area.

2.2 The inspector attended a Plant Operations Review Committee (PORC) meeting on October 31, 1985. Technical Specification 6.5.1 requirements for required member attendance were verified. The meeting agenda included the Cycle 13 Coastdown Operating Guidelines Report. The meeting was characterized by frank discussions and questioning of the proposed report. The PORC review of the coastdown analysis evaluation concluded that plant operation in this mode did not constitute an unreviewed safety question (USQ) and approved the report for implementation during the cycle 13 coastdown. This report assumed that 3-loop plant operation would not be permitted after 380 effective full power days, because the safety analysis margins for the main steam line break accident could not be maintained in this mode of plant operation. The current Technical Specification (TS) limiting conditions for operation (LCOs) allow 3-loop plant operation without limitation with regard to core life, in part because the Main Steam Line Break (MSLB) analysis for 3-loop operation showed adequate safety margin. Approval of plant operation past 380 days without implementing a TS change prohibiting 3-loop operation appears to authorize a change that adversely alters the MSLB safety margin which forms the basis for the current TS. The inspector noted that during the previous fuel cycle (12) a review of anticipated coastdown operations revealed a need to restrict allowable axial offset and linear heat generation rate parameters to more conservative values. In that case, the licensee proposed and NRC issued more restrictive TS LCO conditions on the operating license. The inspector questioned why the need to restrict 3-loop operation for the cycle 13 coastdown was not similarly processed by the licensee. The inspector brought this concern to the attention of the licensee and NRC Licensing on November 1, 1985. The licensee stated that 3-loop operation after 380 days of operation had been administratively prohibited in plant operating procedures. In addition, the licensee committed to process an administrative TS change to prohibit such 3-loop operation and to provide a letter to NRC Licensing explaining the details of the cycle 13 coastdown operation. This item is unresolved pending completion of these licensee commitments and subsequent NRC review (UNR 213/85-21-01).

2.3 Subsequent to PORC approval of the Cycle 13 Coastdown Operating Guidelines Report, the inspector reviewed the implementation of the coastdown safety requirements. The appropriate temporary procedure changes were made and implemented on November 1, 1985 (NOP 2.2-1 NOP 2.2-2, NOP 2.4-3, AOP 3.2-23, ANN 4.5-52, SUR 5.1-75) and control room operating activities were verified to be within the scope of the coastdown requirements. The coastdown report required the resetting of the axial offset setpoints to the coastdown limits. This was satisfactorily performed on October 31, 1985 by work order 85-06486. The inspector will maintain surveillance of coastdown activities during routine operational safety inspections.

2.4 On November 1, 1985, the licensee informed the inspector that an ongoing review of electrical system reliability and failure data had identified a failure mode for motor control center (MCC) 5 during a loss of off-site AC power. MCC-5 is a single 480 volt distribution bus which powers many of the 480 Vital loads such as motor-operated valves for safety injection and charging and letdown isolation valves for both safeguards trains. MCC-5 is powered from either train A or train B vital power supplies through an automatic bus transfer (ABT) device. The newly identified failure mode for this ABT would result in the loss of MCC-5 when all off-site AC power is lost. This loss of MCC-5 would prevent the diesel generator (EDG) cooler outlet valves from opening upon EDG start-up and the EDG's would quickly overheat, leading to a black-out (loss of all AC power) condition.

The licensee blocked the EDG cooler outlet valves open by removing the control air lines which hold them shut. This prevents a loss of AC power event from causing a black-out as a result of the loss of MCC-5. The licensee stated that their review of other MCC-5 loads did not identify other critical components related to the assumed loss of off-site power initiating event. The inspector asked about the effect of the new failure mode on other accidents such as loss of coolant accidents (LOCAs) for which a loss of off-site power is also assumed. A coincident loss of MCC-5 during a LOCA would prevent initiation of safety injection and could lead to core damage. The licensee stated that the probability of a LOCA with loss of off-site AC power and a coincident loss of MCC-5 remains sufficiently low that immediate corrective action is not required. The inspector stated that the details of the new information should be reported to NRC Licensing so that the licensing basis for the Systematic Evaluation Program acceptance of the non-separate/non-redundant MCC-5 bus can be re-evaluated. The licensee committed to make such a report. The NRR Licensing Project Manager was made aware of this matter. Report submission will be checked upon in a future inspection (IFI 85-21-16).

The inspector reviewed the licensee's implementation of temporary modifications made to block open the EDG cooler outlet valves. After consulting with the EDG manufacturer, the licensee determined that the cooler outlet valve closes when the EDG is shut down to assure the diesel

remains preheated for quick starts. Flow through the cooler is thermostatically controlled. The manufacturer stated that leaving the cooler outlet valve open all the time should not over-cool the diesel itself. The licensee conducted a test of the EDGs one at a time, blocking the cooler outlet valve open and monitoring EDG parameters to assure that the EDG remained available for quick starts. The inspector reviewed the test procedure, SPL 10.7-233, and the associated safety evaluation which concluded that blocking the outlet valve open did not create an unreviewed safety question (USQ) unless diesel lube oil temperature dropped below 84 degrees Fahrenheit. During the conduct of SPL 10.7-233 on both EDGs, diesel lube oil temperatures changed less than 2 degrees from operating temperature (about 130°F) when the cooler outlet valves were opened.

The inspector also reviewed the jumper/bypass sheet used to control the temporary blocking of the cooler outlet valves. The licensee had concluded that no technical or safety evaluation of this jumper was necessary. No documentation of or reference to an appropriate safety evaluation was provided. The inspector questioned this because the diesel configuration is described by previous design changes to the Facility Description and Safety Analysis (FDSA) made pursuant to 10 CFR 50.59 in 1975. The licensee stated that the safety evaluation for the special test procedure addressed the adequacy of blocking open the valves and that a special condition of the jumper specified removal of the jumper if the EDG temperature approached the manufacturer's specified minimum value. The inspector agreed that the test procedure, safety evaluation, and jumper control sheet collectively maintained compliance with regulatory requirements. The inspector also noted that the available documents provided no assurance that this temporary modification would be included in the annual report of changes made under 10 CFR 50.59. Inclusion of the EDG cooler outlet valve modification in the next 10 CFR 50.59 Report will be followed in a subsequent inspection (IFI 85-21-02).

3. Observation of Maintenance and Surveillance Testing

The inspector observed various maintenance and problem investigation activities for compliance with requirements and applicable codes and standards, QA/QC involvement, safety tags, equipment alignment and use of jumpers, personnel qualifications, radiological controls, fire protection, retest, and reportability. Also, the inspector witnessed selected surveillance tests to determine whether properly approved procedures were in use, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, procedure details were adequate, and test results satisfied acceptance criteria or were properly dispositioned. The following activities were reviewed:

-- Alarm/Trip Testing of Power Range Nuclear Instruments on 11/8/85, Procedure SUR 5.2-9.

-- High Steam Flow Trip Calibrations on 11/21/85, Procedure SUR 5.2-38.

-- #3 Steam Generator Narrow Range Level Transmitter Replacement on 10/12/85, Work Order 85-06480.

-- Channel 3 Variable Low Pressure Scram Alarm Unit Replacement on 10/11/85, Work Order 85-06299.

-- Resetting Axial Offset Alarm Setpoints on 10/31/85, Work Order 85-06486.

3.1 On October 12, 1985, the licensee replaced the narrow range level transmitter (NRLT) for the #3 steam generator (SG). This instrument provides a partial reactor trip signal (coincident with steam/feedwater flow mismatch) to the reactor protection system. NRC review of this activity concluded that plant administrative control procedures had been violated. However, the operability of the #3 SG level circuitry was subsequently confirmed.

A manual work order (CY-85-06480) was initiated on October 12 to investigate and repair apparent problems with faulty wide range SG level instruments for the #3 SG. The observed problem was a growing deviation between the wide range (WR) and narrow range (NR) instruments. Both the WR and NR instruments are safety-related (Class 1E). The WR instruments are also environmentally qualified (EQ) because their operation is required under post-accident conditions. The original work request was for the WR instruments but the work was not classified as EQ. Had the transmitter replacement been accomplished for the WR instruments, appropriate EQ work controls may not have been applied due to this mis-classification. However, during investigation, the actual problem was localized to a failed NR level instrument, thereby expanding the scope of the original AWO, first to the wide range level transmitter (WRLT) and then to the NRLT. ACP 1.2-5.1, PMMS Trouble Reporting System and Automated Work Order, provides for initiating a supplemental AWO when the scope of work increases. This was not done for the #3 SGLTs. By not initiating the supplemental AWO, such items as Technical Specification applicability and equipment classification/qualification were not updated to reflect the SGLT classification requirements. Although this failure to update the AWO for this activity did not result in significant operational or quality assurance problems, similar failures could be significant. This is an example of failure to conform to the administrative control procedures for maintenance.

The AWO classified the LT as Class 1E, but the Material Issue/Return List used to draw the replacement from stores did not specify this classification. Consequently, the NRLT which was issued and installed was not a certified Class 1E part. (The licensee subsequently upgraded the newly installed component due to its equivalency with the original component.) Procedure ACP 1.2-5.1 requires the AWO originator to properly fill out the CAT/class block of the Material Issue/Return List to insure that properly certified material is used during any repair. A Nonconformance Report (NCR) must be written and dispositioned to authorize the use of

non-safety grade equipment in safety grade applications. The failure to properly fill out the Material Issue/Return List resulted in returning the #3 SGNR level indication system to operation without recognizing the need to disposition the use of potentially degraded materials. This is an example of failure to follow procedure ACP 1.2-5.1. Correction of this individual item will be followed as IFI 213/85-21-04. Other examples of failure to follow procedures are documented in Paragraphs 3.2, 4.6, 7 and 9 of this report. These items have been collectively categorized as a violation (VIO 213/85-21-03).

Subsequent to inspector review of this repair, an NCR (85-194) for the use of a non-class 1E NRLT was initiated on October 16, 1985 and approved on October 23, 1985 with a disposition to use-as-is. In addition, the licensee plans to upgrade all other spare NRLTs to Class 1E. ACP 1.2-15.1, Nonconformance Control, requires that NCRs be dispositioned in a timely manner such that applicable TS Limiting Conditions for Operation (LCOs) are complied with. NCR 85-194 did not identify the LCO related to the NRLT and was given a low priority. The maintenance was performed on October 12 and the nonconforming component was not formally dispositioned until October 23, 1985. Consequently, had the NRLT been unsuitable for use, a significant TS-LCO violation would have existed. The failure to properly identify the LCO relationship of NCR 85-194 on October 16, 1985, and promptly disposition the NCR constitutes a failure to follow Procedure ACP 1.2-15.1. This is an example of failure to follow procedures (IFI 213/85-21-05).

3.2 On October 4 and 11, 1985, the licensee replaced the alarm unit for the channel 3 variable low pressure scram circuit (VLPSC). There are three VLPSC channels in the reactor protection system (2 out of 3 trip logic). With one channel inoperable, it must be placed in the tripped condition to retain the required 1 out of 2 minimum degree of redundancy (TS 3.9). Following these maintenance activities, the licensee determined that the channel 3 VLPSC unit had not been placed in a tripped condition during the repair. The VLPSC channel was rendered inoperable for about 10 minutes during each repair activity. The licensee also determined that the new alarm unit installed on October 4 was not identical to the original unit, requiring the technician to alter the lead termination schedule depicted in plant drawings. In other respects, the alarm units were identical. On October 11, 1985, the original alarm unit which had been removed and repaired was re-installed. The cause of these problems was personnel error, in that the technician did not recognize that the removal of the alarm unit rendered the VLPSC circuit inoperable and that the reversal of leads on the alarm unit constituted a plant modification. The licensee identified and reported both the TS violation and uncontrolled plant modification aspects of the occurrence in Licensee Event Report (LER) 85-26. The licensee committed to upgrade the training of technicians relative to the impact of maintenance activities on the operability of plant equipment and to the control of plant modifications made during maintenance. The inspector reviewed this occurrence to determine why the shift supervisor who approved this maintenance activity did not assure that the TS requirements were maintained. It was deter-

mined that the operators were misled by the technician's description of the work scope and its affect on channel operability. The instrumentation and operations supervisors committed to evaluate measures to improve communications/understanding between the technicians and operators. Since both of the remaining VLPSC channels remained operable during both short duration violations, the safety significance of this event was judged to be low. The inspector considered these items to be licensee-identified violations. The completion of licensee corrective actions will be reviewed in a subsequent inspection (IFI 213/85-21-06).

During inspector review of these maintenance activities, it was noted that the Material Issue List (MIL) under which the new alarm unit was issued on October 4, 1985 was not correctly classified as Category 1 (Class 1E). Therefore, the storeroom should have issued a non-QA replacement unit which was also in stock in the warehouse. The inspector verified that a category 1 unit had in fact been issued and installed in the VLPSC channel. The mis-classification of the MIL and the procedurally incorrect issue of the Category 1 part are examples of licensee failure to follow Procedure ACP 1.2-8.2, Material Issue, Steps 6.1.2 and 6.1.3. Other examples of failure to follow procedures are documented in Paragraphs 3.1, 4.6, 7 and 9 of this report. These items have been collective'y categorized as a violation (IFI 213/85-21-07).

4. Follow-up on Previous Inspection Findings

During the course of the inspection, six NRC open items were reviewed. The inspector found licensee actions with regard to four of these areas to be sufficient to close those items. Details follow:

4.1 (Closed) Unresolved Item (213/80-14-03)

The licensee was to provide an evaluation of observed ultrasonic test (UT) calibration block anomalies identified during the 1980 in-service inspection cycle. The licensee concluded that the 1980 UT deflection anomalies were related to the test block materials (inspected pipes had similar anomalies) and not related to the test equipment or material nonconformances. Further, the licensee has discontinued the use of UT in this application due to subsequent revisions of the ASME Code. These positions were documented in a licensee letter to NRC Region I dated September 16, 1985. NRC has reviewed these findings and concurs that this information resolves NRC concerns in this area.

4.2 (Closed) Follow-up Item (213/84-22-03)

Following two loss of AC power events in August 1984, the licensee committed to develop specific procedures covering long term operation of the emergency diesel generators (EDGs). The licensee implemented Procedure 2.16-6, EDG operation, on April 4, 1985. During NRC review of this procedure, it was noted that the details included in the procedure relative to EDG lube oil monitoring and refilling did not address the

NRC concerns identified during review of the August 1984 loss of power events and IE Circular 80-05, respectively. The licensee committed to review these areas and revise the procedure as necessary. Procedure 2.16-6 was revised on October 18, 1985. Inspector review of this revised procedure determined that both NRC concerns had been satisfactorily addressed. This item is closed.

4.3 (Closed) Follow-up Item (213/84-22-05)

During NRC review of the August 1984 loss of power events, it was determined that the licensee had not specifically established those components/equipment which may be needed to respond to accidents occurring in Modes 5 and 6 in order to plan the return of AC loads or determine which loads need to be immediately picked up on the Emergency diesel generator (EDG) buses. The licensee committed to evaluate which equipment is credited in analyses for accidents in Modes 5 and 6 and to implement controls to assure that adequate power for this equipment is maintained during Modes 5 and 6. Licensee review of this item resulted in a comprehensive list of needed equipment to detect and mitigate shutdown accidents such as fuel handling accidents, boron dilution accidents, or a failed reactor cavity seal. This information was incorporated in plant emergency operating Procedure 3.1-9, Total Loss of AC Power, either by verification of loads automatically picked up by EDGs or by directions for re-energizing specific loads. Control of EDG and off-site power source maintenance has been integrated into outage planning such that adequate power supplies are maintained. The inspector reviewed the licensee's findings and corrective actions, and had no further questions in this area.

4.4 (Open) Follow-up Item (213/84-28-03)

The leakrate test methodology used in Procedures 5.1-1 and 5.1-65 may lead to non-conservative measured leak rates. The licensee committed to evaluate these inadequacies and implement corrective action as necessary. On August 5, 1985, the licensee concluded this evaluation and specified changes to the above procedures. The inspector reviewed the scope of these proposed changes. With the exception of the test of the core deluge check valves, these changes were found to be acceptable. The licensee stated that the present test of the core deluge valves was considered the best possible test. This test was a pressure rise test between the tested valve and a closed (but normally open) manual isolation valve. Since leakage past this second boundary is not verified, the test result could be non-conservative by the magnitude of that leakage. (The pressure source is downstream of the check valve; the manual stop valve is upstream. Manual stop leak-by would decrease the pressure rise and indicate less than actual leakage.) The inspector brought this concern to the licensee's attention. The licensee has developed a new water collection test method to measure the core deluge check valve

leakage. The improved tests will be implemented by procedures prior to the refueling outage starting January 4, 1986. The inspector will follow the completion of this item at that time.

4.5 <u>(Closed) Unresolved Item (213/84-28-05)</u>

The licensee identified premature aging as a cause of certain reactor protection system wiring insulation degradation. The licensee was to report the results of ongoing material failure analyses of the degraded cable harnesses. On October 22, 1985, the licensee submitted Revision 1 to Licensee Event Report 84-17, stating that the wiring insulation used had poor stability in some batches. This resulted from either poor insulation material choice or inadequate stabilization of the material. The licensee concluded, however, that the refueling interval inspection of the newly installed harnesses remains adequate to assure the continued operability of RPS equipment pending implementation of ongoing projects to upgrade/replace the aging RPS system. The licensee also notified the cable manufacturer of the nature of the wiring defects and the results of the completed analyses. The manufacturer has notified other customers of the potential insulation degradation problems by letters dated October 18, 1985. The inspector provided these reports and a sample defective cable harness to NRC Region I for review and follow-up of potential generic implications. This item is closed.

4.6 <u>(Open) Follow-up Item (213/85-13-03)</u>

The licensee identified a repetitive failure to meet the Technical Specification required biennial review of many safety-related procedures. The licensee committed to corrective actions to eliminate the backlog of procedure reviews by September 17, 1985, and to prevent recurrence of this violation. These commitments were documented in NRC Region I Inspection Report 50-213/85-13. The inspector reviewed the status of biennial procedure review as of October 16, 1985. Twenty-two procedures from four plant departments were overdue for review as of that date. Fifteen previously overdue reviews had not been completed in accordance with the licensee's commitment to eliminate the backlog, and seven new overdue reviews indicated that the licensee's measures to prevent recurrence had not been effective. The inspector brought this concern to the attention of plant management on October 28, 1985. The licensee stated that, as of that date, all but one of the overdue procedure reviews had been completed. The inspector re-verified the procedure review status as of November 14, 1985. Three procedures which became overdue as of November 13, 1985 were identified. These procedures were properly reviewed by November 29, 1985. No further discrepancies were identified. TS 6.8 and licensee Procedure 1.2-6.5, Station Procedures, require each procedure for a safety-affecting activity to be reviewed for accuracy/appropriateness at intervals no greater than 2 years. On October 16, 1985, twenty-two safety-related procedures exceeded the required two year interval.

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires identified nonconformances to be promptly corrected and requires corrective action to prevent recurrence of these nonconformances. The licensee's August 1985 actions did not correct fifteen previously identified instances of overdue procedure review, nor did they preclude seven new instances of overdue procedure reviews. This is a violation of corrective action requirements (VIO 213/85-21-08).

5. Follow-up on IE Circulars (IECs), and Information Notices (INs)

5.1 Licensee action on the following IECs and INs was reviewed for prompt forwarding to appropriate management, licensee review for applicability, corrective action commitments, and corrective action completion.

a. IEC 80-05 Lube Oil Addition to Emergency Diesel Generators (EDGs)

This circular documented NRC concern related to licensee control over EDG lube oil refilling operations while the EDGs are in operation. In response to this circular, the licensee provided labels on the EDGs to remind operators of the correct location to refill the lube oil sump during operation. The licensee subsequently included these precaution [illegible] instructions in the EDG normal operating procedure ([illegible] 16-6) appr[illegible] on October 18, 1985. The inspector had no further questions in [illegible] area.

b. IN 84-86 Isolation Betwe[illegible] Signals of the Protection System and Non-Safety-Related Equipment

This information Notice was issued to alert licensees to the potential for failures in non-safety related data multiplexers to adversely affect the safety-related protection system circuit from which the data-collector samples. The inspector verified that this notice was received, reviewed, and assigned for action using plant controlled routing No. 84-1542. The licensee concluded that Haddam Neck was not designed with isolation between safety-related and non-safety-related equipment. This was evaluated during the Systematic Evaluation Program (Topic VII-1.a). The current licensee position on this item is that isolation problems are a small portion of the overall protection system failure risk. NRC Licensing review of this item is currently tracked by Technical Assignment Control No. 51933. With regard to the specific problem noted in IN 84-86, the licensee concluded that the new plant process computer scheduled for installation in 1986-87 will employ a different type of data sampling. This data-collection method uses a flying capacitor circuit in which break-before-make sampling isolates any computer input device failure from the sampled instrument loop. This new isolation technique is also included in SEP Item VII-1.a and TAC No. 51933. The inspector had no further questions in this area.

6. Follow-up on Events Occurring During the Inspection

6.1 Licensee Event Reports (LERs)

The following LERs were reviewed for clarity, accuracy of the description of cause, and adequacy of corrective action. The inspector determined whether further information was required and whether there were generic implications. The inspector also verified that the reporting requirements of 10 CFR 50.73 and Station Administrative and Operating Procedures had been met, that appropriate corrective action had been taken, and that the continued operation of the facility was conducted within Technical Specification Limits.

84-10 Actuation of the Low Pressure Over-Pressure Protection System event detailed in Paragraph 6.2 of this report.

85-13 Misaligned Control Rod Analysis event detailed in NRC Inspection Report 50-213/85-19.

85-23 Missed Fire Protection Surveillance Test

85-24 Auxiliary Feedwater Actuation Valve Failure event detailed in NRC Inspection Report 50-213/85-20.

85-25 Unplanned Gaseous Release event detailed in NRC Inspection Report 50-213/85-19.

85-26 Partial Loss of Variable Low Pressure Scram Protection event detailed in Paragraph 3.2 of this report.

6.2 Actuation of Low Pressure Over-Pressure Protection System (LER 84-10 Revision 1

During a plant cooldown for refueling on August 3, 1984, the reactor coolant system (RCS) low pressure over-pressure protection (LPOP) relief valves opened with indicated RCS pressure at 315 psig. The LPOP relief valve set point is 380 psig. Technical Specification 3.3 and plant procedures required the LPOP system to be in operation whenever RCS temperature is less than 340F. In conformance with these requirements, the LPOP was placed in operation at 10:50 p.m. on August 2, 1984. RCS temperature and pressure were 340F and 315 psig., respectively. Plant cooldown continued until 12:35 a.m. on August 3, when one or both of the LPOP relief valves opened, relieving RCS coolant to the pressurizer relief tank. RCS pressure dropped rapidly. Operators, recognizing that the LPOP system was relieving below the design setpoint as indicated by multiple control room RCS pressure indicators, isolated the LPOP system and RCS pressure stabilized at 295 psig. This condition is allowed for up to 8 hours by Technical Specifications. The LPOP system was restored to operation at 12:52 a.m. on August 3. RCS pressure remained at 295 psig,

so the plant cooldown was resumed. The RCS was depressurized on August 4, 1985 and remained vented until the plant start-up following this refueling outage in October-November 1985.

Licensee evaluation of the event attributed the relief valve opening problem to either relief valve set point drift or RCS pressure indicator problems. The licensee planned to investigate, repair, or replace each of these components, as necessary, during the outage. The inspector reviewed the licensee's original event report (LER 84-10). Several inadequacies were identified to the licensee including a misleading description of the event, indeterminate cause of the event, and incomplete corrective actions. The inspector indicated that a more complete submittal was needed. On July 22, 1985, the licensee submitted an updated LER which correctly described the event sequence and detailed the results of the licensee's corrective actions. Both RCS pressure instruments were upgraded during the outage by replacing the transmitters with environmentally qualified models. Post-installation calibration results were satisfactory. Both LPOP spring-loaded relief valves were reworked and retested with satisfactory set point tolerances. Therefore, the licensee concluded that subsequent LPOP operation would be satisfactory because all the suspect components had been restored to their design specifications. However, the licensee did not perform any as-found testing of either the relief valves or RCS pressure channels, and that prevented determination of the actual cause of the event. Consequently, the cause may not have been corrected and the event may recur. In the LER, the licensee documented a similar occurrence in January 1979. The performance of the LPOP system will be monitored during routine resident inspector coverage of the plant cooldown for refueling on January 4, 1986. Thi item is unresolved pending this review of actual system operation (UN 213/85-21-09).

The lack of as-found test information and of documentation of maintenance details has been previously identified by the NRC and the licensee for improvement of the licensee's maintenance and corrective action programs. Because this event preceded the development of corrective actions in these areas, the inspector concluded that the licensee's response to this event was a further indicator of previously identified problems. NRC review of licensee progress in this area will be reviewed during a subsequent inspection (IFI 213/85-21-10).

6.3 Unplanned Release of Gaseous Radioactivity

On November 1, 1985, an unplanned release of 2 Curies of noble fission product gases occurred when a relief valve for the on-service waste gas storage tank (WGST) momentarily lifted during a transfer of WGSTs. The filtered release to the plant stack terminated itself when the relief valve re-seated within one minute. The peak release rate was 84.7 percent of the Technical Specification instantaneous release limit. The licensee calculated a projected downwind dose consequence at the site boundary of 0.001 mrem.

The release occurred because the single mercoid pressure switch which actuates the solenoid-operated WGST relief valve momentarily tripped when rattled by an operator troubleshooting a perceived malfunction of the WGST transfer system. At the time, the waste liquid degasifier was in operation and filling the waste gas surge tank, which in turn was pressurizing the on-service WGST to near the 200 psig WGST transfer setpoint. (The WGST relief valves are set to open at 225 psig.)

The primary auxiliary operator was monitoring this process. Operator inexperience, combined with previous erratic operation of the mercoid pressure switches which control the waste gas processing system, led the operator to believe that the on-service WGST had not properly transferred to an empty WGST. The operator's concern that either the WGST or the waste gas surge tank reliefs would be lifted resulted in attempts to manually shift WGSTs. When these attempts failed, the operator entered the back of the instrument control panel to determine the cause of the transfer valve failure. (Manual manipulation of the mercoid switches had become an accepted practice for troubleshooting sticking or out of calibration mercoid switches.) In this case, the operator jiggled the wrong (but similarly labeled) pressure switch. This switch, which controls the WGST relief valve, was very close to the trip set point because the WGST was nearly full. The small motion imparted to the switch as the operator checked the connections for air leaks was enough to trip the pressure switch momentarily and create the release.

Control room operators reacted promptly to the plant stack radiation alarms. Degasing operations were stopped, the release was monitored and reported, and the causal factors were established and documented. Inspector review of this event identified five areas of concern to NRC: (1) Operator understanding and control of waste gas system operations failed to assure proper operation of the system; (2) Some question was raised concerning the correct operation of the WGST transfer control logic, in that the operator was unable to manually isolate the on-service WGST; (3) Poor operating history of the mercoid switch control system has led to abnormal/uncontrolled operation of system components by manual manipulation of mercoid switches; (4) The similar labeling and close arrangement of these switches is not conducive to the manual troubleshooting techniques applied to these components; and (5) The use of mercoid pressure switches for the WGST relief valve operators which are easily tripped open by small motions at the time of the highest magnitude of waste gas release consequences (highest WGST pressure and highest waste gas activity) is a questionable system design. The inspector brought these concerns to licensee management attention. The licensee installed signs near the mercoid switches warning operators of the sensitivity of these controls New instructions to operators prohibit manual manipulation of these control switches and require terminating waste gas system operations and contacting instrumentation personnel when abnormal system operation is suspected. Further licensee review of this event is ongoing. Preliminary checks of control system setpoints identified no out of tolerance or defective components. NRC review of this event and the

above concerns remains unresolved pending the completion of the licensee's evaluation and implementation of corrective actions (UNR 213/85-21-11).

6.4 High Steam Flow Plant Trips

On November 10, 1985, the plant tripped from full power due to high steam flow from 3 of 4 operating steam generators (SGs). Plant systems responded normally. The operators stabilized the plant in hot standby. NRC and state officials were promptly notified. Licensee investigation concluded that the main steam excess flow check valve, which is a main steam isolation valve (MSIV) for the #3 SG, drifted off its open seat. As a result, the steam flow decreased from #3 SG and increased from the other three SGs until the 110% steam flow trip setpoint was reached. Upon actuation of the 2 out of 4 high steam flow logic, all four MSIVs closed and the reactor and main turbine were tripped by the reactor protection system. MSIV trip tests before and after this plant trip showed that the #3 MSIV was consistently the slowest operating MSIV. The fact that #3 MSIV was the first MSIV to close during the event resulted in the determination that this valve must have been partially closed at the initiation of the trip. The licensee replaced the solenoid-operated valve (SOV) which holds the #3 MSIV open. (The identical SOVs for the other MSIVs had been previously replaced with a newer model SOV.) Following this replacement, the #3 MSIV operating time was significantly reduced. The licensee resumed plant operation on November 11, 1985, based on the conclusion that the old SOV had allowed the #3 MSIV to drift off the open seat causing the trip and that SOV had been replaced and fully tested. The licensee has not been able to reproduce a failure mechanism in the old SOV which would explain the observed behavior. This aspect will be followed during NRC review of the Licensee Event Report submitted for the event.

On November 21, 1985, a second high steam flow plant trip occurred during surveillance testing of the high steam flow trip channels. The plant was operating at nearly full power, in an end-of-core-life coastdown mode, with reactor temperature decreasing as fuel depletion increased. This plant temperature reduction causes the non-density compensated main steam flow channels to drift upward toward the high steam flow reactor trip setpoint (110% of normal flow). The licensee was in the process of calibrating one of the four high steam flow channels when two other channels spuriously actuated causing the plant to trip. Plant safety systems functioned properly during this trip, and the plant was stable in the hot standby mode within 15 minutes. Event notifications were completed promptly. Licensee investigation of this event identified no linkage to the previous high steam flow trip. The licensee proved that some cross-talk between high steam flow channels 1, 2 and 4 exists. In tests performed after the trip, the licensee showed that the cross-talk observed between these channels tends to trip the channel rather than prevent a trip. Spurious channel actuations occur only when the observed steam flow is within 3-4 percent of the high steam flow trip setpoint.

In that case, a high test signal in one channel can cause spurious actuation of multiple channels. The licensee established administrative controls to monitor the margin to the trip setpoint in each high steam flow channel and to maintain that margin greater than 8 percent by controlling plant load. The plant resumed operation on November 22, 1985. NRC review of the generic implications of reactor protection system channel interference will be followed in a subsequent inspection (IFI 213/85-21-12).

7. Implementation of Temporary Procedure Changes

During routine inspector review of plant operations, several temporary changes to plant procedures were noted. Plant Technical Specifications (TS 6.8) require that such changes be reviewed and approved by the onsite review committee and Station Superintendent within 14 days of initiation of a temporary change. Plant procedure 1.2-6.4, Temporary Procedure Change (TPC), defines administrative controls to assure the correct disposition of TPCs. The inspector reviewed the licensee's records for the following TPCs to verify the correct disposition of these changes:

-- TPC dated September 17, 1985, to procedure 5.3-23, Excore-Incore Axial Offset Correlation, Revision 11 (TPC 85-101)

-- TPC dated September 16, 1985, to procedure 5.1-26, Incore Power Distribution Monitoring, Revision 5 (TPC 85-123)

-- TPC dated September 16, 1985, to procedure 2.2-2, Steady State Operation, Revision 19 (TPC 85-124)

-- TPC dated October 19, 1984, to procedure 10.7-219, Core Cooling Using PORVs, Revision 0 (TPC 84-185)

No record of review and approval was found for the latter three of these four TPCs. The inspector brought this discrepancy to the licensee's attention. The licensee determined that no PORC review of these three TPCs was conducted. The changes were then reviewed, found acceptable, and approved at PORC meetings 85-110 and 85-113. In addition, the licensee tasked each department head with reviewing all procedures under his cognizance to determine if any further outstanding TPCs exist. None were reported. The failure to control the disposition of these three TPCs to insure that the required review and approval was completed within 14 days is contrary to administrative control Procedure 1.2-6.4. Several other examples of failure to follow procedures were identified in Paragraphs 3.1, 3.2, 4.6 and 9 of this report. These items have been collectively categorized as a violation. Follow-up on this specific instance will be accomplished under IFI 213/85-21-13.

8. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specification 6.9 were reviewed. This review verified that the reported information was valid and included the NRC required data; that test results and

supporting information were consistent with design predictions and performance specifications; and that planned corrective actions were adequate for resolution of the problem. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following report was reviewed:

-- Monthly Operating Report 85-10

This report covers plant operation from October 1-31, 1985. No unacceptable conditions were identified.

9. Review of Modifications to the Power-Operated Relief Valves (PORVs)

During the August-November 1984 refueling outage, the licensee modified the PORV system to upgrade this system to a Category 1 status. These modifications were implemented to support the use of the PORVs for reactor core cooling using a feed and bleed methodology. This design change was documented in Plant Design Change Request (PDCR) 622, Core Cooling Using PORVs, and Revision 1 to that PDCR. The inspector reviewed the documentation and implementation of these changes to verify the quality of the installation and testing and the completeness of the documentation. The inspector concluded that the system upgrades had been satisfactorily accomplished. However, several inadequacies were identified in the design change control measures applied to these modifications as discussed below:

a) Inspector review of the PDCR 622 documents revealed that several quality assurance (QA) records, such as the original, approved PDCRs and certain functional test records, had not been turned over to the nuclear records department. These QA records were found in various engineers' files and were not strictly controlled in temporary storage. QA records regarding ongoing design work are often maintained by the project engineer until completion of the work package. In this case, the licensee expects to do more work on the PORVs and is holding this PDCR open. Consequently, some QA records of completed work have been uncontrolled for over nine months. Upon notification of this problem, the licensee committed to retrieve original copies of all ongoing PDCRs and establish controlled temporary storage in the engineering office for such documents. The inspector observed the implementation of this commitment in accordance with Engineering Department memorandum 85-1088 dated October 7, 1985. The inspector had no further questions on this item.

b) Inspector review of the pre-operational testing performed for PDCR 622 revealed that the documented pre-operational test (SPL 10.7-219, Core Cooling Using PORVs) implemented in accordance with the licensee's design change control procedures was incomplete. This occurred because certain system anomalies, identified durng the testing, prevented completion of the system pressure drop test. Revision 1 to the PDCR was implemented to correct these deficiencies, which were related to air leakage past the air pressure regulators. These changes were implemented by work order (AWO) #85-08964. This work order did not reference the appropriate

PDCR in the task description, nor did it specify the approved pre-operational test procedure in the retest requirements of the AWO. These specifications are required by Procedure ACP 1.2-5.1, Trouble Reporting and Automated Work Orders. The only retest of the PORVs was a valve stroke test. Consequently, the approved pre-operational test was not completed under this work order. However, an unapproved, uncontrolled functional verification of the PORV system did demonstrate the leak tightness of the modified system. This functional verification record was added to the QA records for this modification. The licensee's failure to perform and document system retests in accordance with Procedure ACP 1.2-5.1 constitutes a failure to follow this procedure and is contrary to Technical Specification 6.8, 10 CFR 50, Appendix B, Criterion V and the licensee's quality assurance program. Other instances of failure to follow procedures are identified in paragraphs 3.1, 3.2, 4.6 and 7 of this report. These items collectively constitute a violation. Follow-up on this item will be pursued as IFI 213/85-21-14.

c) The inspector also identified that the procedures required to implement some of the surveillance tests for the modified PORV system have not yet been written. Procedure ACP 1.2-3.1, Preparation, Review and Disposition of PDCRs, requires all surveillance procedures to be implemented within one month of the completion of the design change. The licensee had assigned a controlled routing to follow this open item with a due date prior to the next refueling. This assignment was contrary to the requirement of Procedure ACP 1.2-3.1. The licensee committed to review other PDCRs implemented during and since the 1984 refueling outage to assure that no other surveillance test procedures are outstanding. This example of failure to follow procedures will be followed up as IFI 213/85-21-15).

10. Unresolved Items

Unresolved items are matters about which more information is required in order to determine whether they are acceptable items or violations. Unresolved items identified during this inspection are discussed in Paragraphs 2.2, 6.2, and 6.3.

11. Exit Interview

During this inspection, meetings were held with plant management to discuss the findings. No proprietary information related to this inspection was identified.