U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report/Docket No.	50-213/93-12
License No.	DPR-61
Licensee:	Connecticut Yankee Atomic Power Company P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Plant
Location:	Haddam Neck, Connecticut
Dates:	June 20, 1993 to July 24, 1993
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Approved by: Richard J. Barkley / 8/18/93
Lawrence T. Doerflein, Chief — Date
Reactor Projects Section No. 4A, DRP

Areas Inspected: NRC resident inspection of plant operations, outage activities, event response, maintenance, engineering and technical support and plant support activities.

Results: See Executive Summary

EXECUTIVE SUMMARY

HADDAM NECK PLANT INSPECTION 50-213/93-12

Plant Operations

Safe facility operation was noted throughout the period as the refueling outage was completed and the plant was returned to power operation. Good control of shutdown risk was noted during the period in the planning of daily station activities. The inspector noted very good operator coordination and control of the plant when reactor coolant loop #2 was isolated and cooled down to support maintenance on main steam safety valve MS-SV-21.

Operators responded very well following two loss of normal power events, and a loss of power to a 480 volt motor control center (MCC 5) with the plant in Mode 5. The operators quickly stabilized the plant and restored decay heat removal and spent fuel pool cooling. The failure of an operator to adequately check his actions during a routine surveillance test caused a reactor trip while critical on July 19. Operator followup to the reactor trip was also good.

Plant operators performed very well during the plant restart and resumption of power operations. One exception to otherwise good performance was the failure to have main steam line flow instruments operable in Mode 3. Enforcement discretion was exercised for this issue in view of the licensee's identification of the problem and the thorough followup actions (Section 2.5). Operator action was good to mitigate reactor coolant system pressurization transients during testing on July 7 and 9. The verification that the low temperature over pressure (LTOP) relief valves functioned as designed during the pressure transients is an unresolved item (Section 2.4).

Maintenance

The inspector noted during observation of electrical maintenance activities, that electricians observed proper safety requirements, and adhered to the breaker replacement specifications within the applicable work orders. The licensee's root cause evaluation for the high pressure safety injection pump abnormal bearing wear was self-critical. The evaluation was extensive and supported a timely operability determination for the pumps.

The failure by contractor maintenance personnel to adequately self-check work while overhauling main steam safety valve 21 resulted in the failure of the valve to lift at the specified setpoint during subsequent testing. Also, the failure of safety valve test rig prevented a second valve from reseating properly after a successful lift during testing. The inadequate special test for the vital inverters, and insufficient guidance within a check valve surveillance resulted in two challenges to the low temperature overpressure system.

Engineering and Technical Support

The combination of a quality test procedure, knowledgeable test personnel, and quality service department observation resulted in a safe, efficient, low-power startup test program. The need to develop a programmatic plan to validate the use of stem friction coefficients for thrust calculations for motor operated valves is considered an unresolved item (Section 4.1).

The instantaneous overcurrent setpoints for Westinghouse type HMCP 480 volt breakers were changed under plant modification 1336, as a result of safety-related loads tripping prematurely. The changes were made to account for the current transients associated with the motor control center (MCC)-5 automatic bus transfer operation, and the "plugging" and "jogging" of valve loads supplied by the breakers. Corrective actions were acceptable.

Plant Support

The monitoring and control of radiological activities were good. Written reports submitted pursuant to 10 CFR 50.73 and the technical specifications accurately described significant events and the associated corrective actions. The control of security weapons and the training program for new security officers were acceptable.

Following the loss of motor control center 5 on June 27, an Alert classification was erroneously sent to the state and towns. The event classification was properly reported as an unusual event a short time later. The event was properly classified by shift personnel, but was miscommunicated as an Alert. The reason for this error was determined to be a performance error by a non-licensed shift member who transmitted the message.

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Note: The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

The unit began the inspection period in a refueling condition (Mode 6). The reactor head was tensioned, and the unit entered cold shutdown on June 22. During electrical distribution surveillance testing, loss of off-site power events occurred on June 22 and June 26. On June 27, while performing surveillance testing, a loss of motor control center (MCC)-5 occurred when the automatic bus transfer scheme failed to operate. On July 6, the unit experienced a loss of two 120 volt vital buses resulting in an unplanned engineered safety feature actuation (report detail 3.5). During surveillance testing on July 7 and July 9, pressurization transients occurred in the reactor coolant system (report detail 2.4).

Startup began on July 11, when the plant was heated up to Mode 4. The plant entered Mode 3 on July 13, and initial criticality for Cycle 18 occurred at 3:55 a.m., on July 18. A trip occurred with the reactor at zero power at 2:47 p.m., on July 19. At the end of the inspection period, the licensee completed the refueling maintenance outage and the unit was at 80% rated thermal power.

2.0 PLANT OPERATIONS (71707 and 93702)

In addition to normal utility working hours, the inspectors routinely reviewed plant operations during portions of backshifts (evening shifts) and deep backshifts (weekend and night shifts). Inspection coverage was provided for 40 hours during backshifts and 33 hours during deep backshifts.

2.1 Operational Safety Verification

This inspection consisted of selective examinations of control room activities, operability reviews of engineered safety feature systems, plant tours, review of the problem identification systems, and attendance at periodic planning meetings. Control room reviews consisted of verification of staffing, operator procedural adherence, operator cognizance of control room alarms, control of technical specification limiting conditions of operation, and electrical distribution verifications. Administrative Control Procedure (ACP) 1.0-23, "Operations Department Shift Staffing Requirements," identifies the minimum staffing requirements. During the inspection period, the inspector noted that control room staffing during the refuel outage and power operations met these requirements.

The inspectors reviewed the on-site electrical distribution system to verify proper electrical line-up of the emergency core cooling pumps and valves, the emergency diesel generators, radiation monitors, and various engineered safety feature equipment. Good control of shutdown risk was noted in the planning of daily station activities and through the use of the system status board in the control room. The inspectors also verified valve lineups, position of locked manual valves, power supplies, and flow paths for the high pressure safety injection system, the low pressure safety injection system, the containment air recirculation system, the service water system, and the emergency diesel generators. No deficiencies were noted.

Log-Keeping and Turnovers

The inspectors reviewed control room logs, night order logs, plant incident report logs, and crew turnover sheets. No discrepancies or unsatisfactory conditions were noted. The inspectors observed crew shift turnovers and determined they were satisfactory, with the shift supervisor controlling the turnover. All members of the crew discussed plant conditions and evolutions in progress. The information exchanged was accurate. The inspectors also reviewed control room trouble reports for age, planned action, and operator awareness of the reason for the trouble report. The majority of trouble reports reviewed were recent, with few longstanding items.

At daily planning meetings, the inspectors noted discussions on maintenance and surveillance activities in progress, and planned work authorizations. The inspectors conducted periodic plant tours in the primary auxiliary building, containment, turbine building, and intake structures. Plant housekeeping was satisfactory.

2.2 Hurricane Readiness

The objective of the inspection was to evaluate the depth and content of licensee procedures for responding to a postulated hurricane. The inspection consisted of interviews with cognizant licensee personnel, and review of Abnormal Operating Procedure (AOP) 3.2-5, "Natural Disasters," Emergency Plan Implementing Procedure (EPIP) 1.5-2, "Notification and Communication," and AOP 3.2-24, "Flooding of the Connecticut River."

The inspector noted that a back-up communication method exists if the phone lines are damaged. The procedures require that the plant be shutdown, and provide guidance on securing loose plant equipment prior to the arrival of a hurricane. The inspector noted that a site vulnerability is the potential blockage of the sole facility access road by hurricane generated debris. This is recognized in the procedures and actions would be taken to clear the road as needed. The licensee demonstrated appropriate planning prior to winter storm Joshua in March 1993, as documented in report 50-213/93-03. The inspector did not identify any weakness in the licensee's procedures for a postulated hurricane.

2.3 Loss of Power Events

On June 22, 1993, while performing breaker failure trip logic testing on the offsite power tie breaker, the station experienced a total loss of offsite power. Both emergency diesel generators automatically started and provided emergency power to the station. The plant was in cold shutdown at the time of the event and shutdown cooling was quickly restored.

Operator performance in response to the loss of offsite power was good. The root cause for this event was a wiring error in the breaker 12R-1T2 trip logic. The wiring error occurred during or shortly following plant construction. The wiring error had not been previously identified since this was the first test conducted of the breaker failure trip logic. The licensee's evaluation of the wiring error's effect on plant safety concluded that the error did not degrade plant safety margins and could be left as is. The root cause was correctly identified and the corrective actions were acceptable.

On June 26, 1993, while performing surveillance testing of the "A" train of the safety injection actuation logic with a partial loss of offsite power, a complete loss of offsite power occurred. The emergency diesel generators automatically started and shutdown cooling was restored. The operator response to the loss of offsite power was good. The root cause of this failure was determined to be a blown fuse to a bus voltage sensing relay. The fuse was likely blown during maintenance performed on associated equipment. The fuse was replaced and the surveillance procedure was revised to verify that the bus voltage sensing relay fuses were not blown prior to conducting this test. The root cause for this event was positively identified and the corrective action taken were appropriate. The June 22 and June 26, events were not related in that the corrective actions from the first event could not have precluded the second event from occurring.

On June 27, 1993, while performing surveillance testing of the "B" train of the safety injection actuation logic with a partial loss of offsite power, a temporary loss of motor control center 5 occurred, when the automatic bus transfer (ABT) scheme failed to operate correctly. Power was quickly restored to the motor control center by manually closing a breaker to an energized bus. A detailed and thorough evaluation of this event failed to positively identify a root cause. The evaluation did identify two components which had the highest probability of having caused the failure. Both components were replaced and the ABT was successfully tested numerous times since the event. During this event, an erroneous event emergency classification of an Alert was sent to the state and towns. The event classification was corrected to an Unusual Event a short time later. The event was properly classified by shift personnel, but was miscommunicated as an Alert. The reason for this error was determined to be a performance error by a non-licensed shift member who transmitted the message.

An Augmented Inspection Team (AIT) inspection was conducted on June 30 to July 9, 1993. The team conducted a detailed review of the circumstances surrounding the June 22 and June 26, losses of offsite power, and the June 27, loss of motor control center 5. The AIT developed a detailed sequence of events, evaluated the root cause determination, assessed the effectiveness of the corrective actions, and evaluated the safety significance of each event. The AIT inspection findings are detailed in Report 50-213/93-80.

2.4 Low Temperature Overpressure Events

The mitigating system for reactor coolant system (RCS) overpressure protection at low temperatures uses two spring relief valves (PR-RV-587, 588). The valves are isolated from the pressurizer/reactor coolant system during normal operating conditions by two motor operated isolation valves. The relief valves are Crosby model number JB-35TD-WR with a setpoint of 380 psig, and a relieving capacity of approximately 800 gallons per minute (gpm) at 380 psig. The valve setpoint and surveillance requirements are detailed in Technical Specification (TS) 3.4.9.3. The valves are removed from service prior to the RCS reaching 315 degrees Fahrenheit (°F). The discharge from the valves is collected in the primary relief tank (PRT).

During the inspection period, the RCS experienced two pressure transients that challenged the low temperature overpressure (LTOP) relief valves. The first event occurred on July 7, at approximately 5:37 p.m. The licensee was performing Special Test (ST) 11.7-127, "Test of "C" and "D" Inverters," when solenoid valve (CH-SOV-110) deenergized, allowing the charging flow control valve to travel full open. The unit was in a water-solid condition with initial RCS pressure at 300 psig and temperature of 114°F. The highest pressure as recorded from the narrow range RCS pressure transmitter was 430 psig. No change was recorded in RCS temperature. The pressure transient was mitigated by quick operator action to terminate the mass addition, and by the operation of the LTOP valves.

The second event occurred on July 9, at approximately 3:00 p.m. Control room operators were implementing SUR 5.7-31, "Inservice Testing of Boric Acid and RWST Check Valves BA-CV-320, 372, and 387," when, due to a charging system alignment error, a RCS pressure transient occurred. The unit was again in a water-solid condition with initial RCS pressure at 300 psig and RCS temperature at 148°F. The highest recorded pressure transient on the narrow range instrument was 455 psig. The pressure transient was mitigated by quick operator action to terminate the mass addition, and by the operation of the LTOP valves.

The inspection of the operational events focused on licensee root cause determination and corrective actions, and verification of the LTOP relief valve design function. The review consisted of interviews with cognizant individuals, verification of plant response, evaluation of the procedures in-use at the time, and a review of the design basis documents for the LTOP relief valves.

Root Cause/Corrective Actions

The root cause of the overpressure transient on July 7, was a procedure deficiency. The purpose of Procedure ST 11.7-127 was to demonstrate that one vital 120 volt AC inverter (C or D) could supply uninterrupted power to both vital buses "C" and "D" during the loss and restoration of MCC-12 (see report detail 3.5). ST 11.7-127, Step 6.9.4 requires deenergizing vital bus "D". Upon loss of vital bus "D", the solenoid valve CH-SOV-110 deenergizes, causing the flow control valve (CH-FCV-110) to open. The solenoid valve and flow control valve functioned as designed during the loss of vital bus "D". The developers of the special test procedure did not recognize this function nor were instructions provided on how to prevent a pressure transient. AOP 3.2-15, "Loss of Vital Bus," Step 3.4.2. states that on a loss of vital bus "D," charging flow control valve CH-FCV-110 fails open. The AOP instructs the operator to manually control the charging system.

The inspector discussed the procedure development with the system engineer and operations personnel. ST 11.7-127 was developed to verify proper operation of the "C" and "D" vital inverters based on a loss of vital buses during the refueling outage. The development, review, and plant operations review committee (PORC) approval took approximately one day. The system engineer did not feel pressured to develop the procedure; however, he was aware of the outage schedule plan to enter operational Mode 4 later in the week. No schedule pressures or demands were made by management on the system engineer. The individual recognized the error in the procedure after the LTOP event. In discussions with operations personnel, the reviewer stated that he was focused on the need to avoid a spurious engineered safety feature signal, which had been generated during vital bus testing earlier in the week. The procedure error was also masked during previous successful testing on vital buses "C" and "D", which did not affect the RCS pressure, since the plant was not in a water-solid condition. CYAPCo management concluded that the event was due to a wrong set of priorities, and an insufficient procedural review.

The initial action by operators to terminate the event was to re-energize vital bus "D" and close the charging flow control valve. The PRT level rose from 75% to 95%, and pressure increased from 3 psig to 14 psig, confirming that the relief valve opened. After the pressure transient, control room operators had health physics personnel perform a containment sample to determine if any unusual airborne radiation levels existed. The surveys indicated no abnormal results. The licensee concluded that the pressure transient was below the hydrostatic/leak test curve limit of approximately 750 psig. The licensee's basis for use of the hydrostatic curves was that the pressure transient occurred during iso-thermal conditions. After the transient, the licensee prepared a procedure change to ST 11.7-127 and continued with inverter testing. At the end of this inspection report, CYAPCo was processing a special report pursuant to TS 3.4.9.3.c.

The root cause for the event on July 9, was determined by the licensee to be a procedural deficiency. The operators were performing Procedure SUR 5.7-31 as a post-maintenance retest for the boric acid strainer discharge check valve (BA-CV-320). The procedure did not provide specific guidance on the alignment of the discharge charging and fill headers. Prior to the transient, the operating charging pump was controlling pressure through the charging header. To obtain the required flow through the boric acid strainer discharge check valve, the operators aligned the charging system in a manner that unknowingly provided a flowpath from the operating charging pump through the non-operating charging pump piping and into the charging fill header. The operator immediately shut the charging fill header valve (CH-MOV-508) to stop the RCS flow imbalance, and reduce RCS pressure. CYAPCo corrective actions for the July 9 event were to depressurize the reactor coolant system, stop all work connected to the reactor coolant system, and brief the shifts on the recent operational events prior to the release of work activities. The licensee commenced RCS work activities on July 10. Long-term corrective actions for this event were in process at the end of the inspection period. At the end of the inspection period, the licensee was processing a special report pursuant to TS 3.4.9.3.c.

The inspector noted that TS 3.4.9.1.c. states that inservice hydrostatic and leak testing is deemed to be in progress when both of the LTOP systems are removed from service, the RCS cold leg temperature in at least one unisolated RCS loop is less than 315°F and the RCS is not depressurized with a vent greater than or equal to seven square inches. Based on the above, the inspector concluded that the hydrostatic curve is not applicable to the pressure events. The NRC position is that TS Figure 3.4-3 should only be applied during RCS hydrostatic or leak inspections, and that TS Figures 3.4-4 and 3.4-5 should be applied during all other plant conditions. This issue was discussed with the licensee, who subsequently accepted the NRC position. The licensee evaluated TS Figure 3.4-4 and removed the instrument uncertainties within the curves, and added the maximum instrument uncertainty to the RCS pressure indications during both overpressure events. The licensee concluded that RCS pressure did not exceed TS Figure 3.4-4 during either event. The inspector verified the licensee's conclusion that Figure 3.4-4 was not violated.

Design Basis of the LTOP Relief Valves

The design basis for the LTOP relief valves is documented in the technical specification basis and the Updated Final Safety Analysis Report (UFSAR). The TS basis states that either relief valve has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either a start of a charging pump and its injection into a water-solid RCS; or a reactor coolant pump start with secondary water temperature of the steam generator less than or equal to 20°F above the RCS cold leg temperatures. UFSAR Section 5.4.16 states that the spring-loaded relief valve setpoint was chosen such that the maximum pressure (i.e., setpoint pressure plus valve overshoot during a mass addition transient) is less than the lowest pressure allowed by the pressure temperature curves.

Northeast Utilities Service Company (NUSCo) calculation 77-502-49GM in 1978 documented the design basis for the valve setpoint, the capability to mitigate mass addition during water-solid conditions, the verification of appropriate vent size for overpressurization, and the relief valve flowrate related to system back-pressure. The calculation acceptance criteria referred to 10 CFR 50, Appendix G limits for the reactor pressure vessel.

The inspector also questioned if the LTOP design function (UFSAR 5.4.16.) was maintained since the RCS pressure exceeded the 425 psig stipulated in NUSCo calculation 77-502-49GM. The licensee believes that the function was preserved based on the removal of instrument uncertainties in TS Figure 3.4-4. The inspector considers this issue unresolved pending further licensee review of NUSCo calculation 77-502-49GM conclusions and comparison with the pressure transients on July 7 and July 9 **(URI 50-213/93-12-01)**.

The licensee received a Westinghouse Information Notice in May 1993. The information notice alerted licensees that previous LTOP calculations did not account for the dynamic pressure drop across the reactor core. NUSCo Stress Engineering personnel concluded that the information notice was applicable to Connecticut Yankee. The licensee concluded that the pressure drop across the core resulted in approximately 27 psid. When this error was combined with additional instrument uncertainties, NUSCO engineering determined that the potential non-conservatism in the TS pressure/temperature limits was 105 psig in the operating range above 315 F. Based on the results, the licensee modified the TS pressure/temperature curves by using Operations Department Instruction (ODI)-169, Attachment 4, to provide the revised curves to operators.

For the revised curves, no change was necessary in the LTOP region (i.e., RCS temperature less than 315°F) since the existing pressure tolerance of 60 psig was adequate. The wide range RCS pressure instrument used at Haddam Neck had an instrument tolerance which was bounded by those assumed in the Westinghouse Information Notice. The inspector confirmed the licensee developed ODI-169, Attachment 4, prior to entry into plant cooldown for the refueling outage. The licensee initiated a reportability evaluation form (REF) 93-18 on May 10, to evaluate if the non-conservative RCS pressure/temperature limits was reportable to the NRC. On July 2, the licensee's REF concluded that the condition was not reportable, and the overpressure protection system was operable. The basis for this conclusion was that assurance exists that the temperature/pressure curves were not exceeded, especially in the critical areas of the LTOP region, due to the LTOP valves not lifting and based on the implementation of a requirement to use narrow range pressure indication for verification of compliance to TS pressure and temperature curves. The narrow range pressure indication further assured the instrument uncertainties were bounded by the 105 psig limits.

Conclusion

Due to two procedure deficiencies, the licensee challenged the overpressure protection system. The licensee conclusion for the root cause of both overpressure events was appropriate. The inspector determined that outage scheduling was not a factor in the development of an inadequate special test procedure. The inspector noted that the surveillance procedure lack appropriate controls to ensure that the RCS was not subjected to a overpressure condition. Licensee verification of and NRC review that the LTOP relief valves functioned as designed is an unresolved item.

2.5 Inoperable Main Steam Line Flow Instruments

During routine inspections on July 14, of work they had performed under plant design change record (PDCR) 1331, Instrument & Control (I&C) technicians noted that main steam line flow instruments FT-1202-1, 1202-2, 1202-3 and 1202-4 were isolated. The technicians had placed the instruments in service when the channels were last tested on July 1, and expected to find the instruments in service on July 14. The technicians immediately notified the control room operator of the status of the instruments, and placed the instruments back in service at about 1:00 p.m., by opening the high and low side isolation valves, and closing the equalizing valve on each transmitter.

The plant was in Operational Mode 3 at the time with the reactor coolant system at normal operating conditions of 532°F and 2000 psig. All control rod banks were inserted and the reactor coolant system was borated to the refueling boron concentration of 2487 ppm. The licensee considered the discovery of the isolated instruments as a significant loss of control of the status of plant instrumentation system and began investigation to determine its cause and what additional corrective actions were warranted. The incident was documented in Plant Information Report 93-166. The licensee determined the event was reportable under 10 CFR 50.73(a)(2)(i)(B) as a condition prohibited by the plant technical specifications.

The plant shutdown for the 1993 refueling outage on May 15. CYAPCo determined that the transmitters were manipulated during surveillances SUR 5.2-38.1 through 4, and ST 11.2-6 during the refueling outage. Both surveillances are part of the channel tests and calibrations performed as part of PDCR 1331, and both surveillances use independent verification to return the channels to service following each test activity. The last test conducted on the channels was ST 11.2-6 which was completed on July 1. The plant was in operational Mode 5 upon completion of the PDCR 1331 test on July 1, which left the channels aligned for service and plant startup.

The plant startup from the refueling outage began on July 11, when the plant was heated up to Mode 4, and the plant entered operational Mode 3 at 1:32 a.m., on July 13. The main steam line flow instruments were returned to an operable status at 1:00 p.m., on July 14. The licensee concluded that the transmitters were removed from service some time between July 1 and July 14. An investigation to determine how and why the transmitters were removed from service was in progress at the end of the inspection period.

Safety Significance

Flow transmitters FR 1202-1 through 4 sense main steam line flow rate using a flow tap on each steam line located outside of the primary containment. The transmitters are used to sense a break in a main steam line, and the associated instrumentation channels are used to generate a reactor trip signal and an engineered safety features (ESF) actuation signal.

Each transmitter provides a signal input into the reactor protection system, which trips the reactor when high steam flow is detected in any two of the four steam lines. Technical Specification Table 3.3-1 requires that the reactor trip instrumentation be operable when the plant is operating in Modes 1 and 2. Each transmitter also provides an input into the ESF system to close the main steam trip valves (MSTVs) when high steam flow is detected in any two of the four main steam lines. Technical Specification Table 3.3-2 requires that the ESF instrumentation be operable when the plant is operating in Modes 1, 2 and 3. With one or more trip channels inoperable, the TS 3.3-2 Action Statement requires that the reactor be placed in a hot shutdown condition (Mode 4) within 16 hours.

The RPS and ESF functions are designed to mitigate the consequences of a main steam line break by tripping the reactor and isolating the main steam lines. During the period from July 1 through 14, the reactor trip breakers were open and the control rod banks were inserted in the core. MSTVs MS-TV-1211-1 through 4, were closed during the subject period, but were opened as necessary to support surveillance testing starting at 9:55 p.m., on July 11. During the period that the ESF actuation channels were required to be operable but were not (i.e., from 1:32 a.m., on July 13, until 1:00 p.m., on July 14), there was no steam in the steam lines downstream of the MSTVs since steam had yet to be admitted to the turbine plant as of that time in the startup sequence.

Further, regardless of the status of the MSTVs, the main steam non-return valves, MS-NRV-11, 12, 13 and 14, which are located upstream of the MSTVs, were closed and had been tagged closed to the shift supervisor since the start of the outage on May 15. Thus, notwithstanding the status of the transmitters, plant safety was not degraded during the period of inoperability, because: (i) a steam line break down stream of the MSTVs could not have occurred due to the status of the plant, and (ii) a main steam line break upstream of the MSTVs would have been mitigated by the main steam non-return valves and the shutdown status of the reactor. Based on the above, the inspector concluded that the actual plant safety significance of the inoperable transmitters was low.

Corrective Actions

In addition to the immediate and short term followup actions described above, the licensee also completed a review to assure RPS and ESF instrumentation channels were properly aligned for service. This was accomplished through the completion of inspections and checks per PMP 9.2-29, "Safety Class Instrument Inspections." It is notable that this check is normally performed prior to taking the reactor critical (scheduled within 12 hours of entering Mode 2), and this check likely would have discovered the inoperable transmitters had the technicians not done so on July 14.

The licensee's initial reviews did not identify how the transmitters became isolated. Because of its significance and the implications raised by the event on the adequacy of the administrative controls for controlling system status for plant mode changes, plant management directed that a formal root cause analysis and human performance evaluation system (HPES) review be performed. These evaluations were in progress at the conclusion of the inspection. The licensee stated he will report the results of his evaluations and additional corrective actions in the licensee event report. Additional long term corrective actions will be developed based on the results of the HPES evaluation. NRC review of further corrective actions will be included in subsequent routine inspections of licensee event reports for Haddam Neck.

Conclusions

The inspector independently verified on July 16, that transmitters FT-1202-1 thorough 4 were properly restored to service. The inspector also verified that other safety channels were responding as expected based on channel checks that were performed as allowed by plant conditions. The inspector reviewed the licensee's initial investigation of the event, including the management interview with the I&C technicians. CYAPCo followup actions were prompt, appropriate and thorough. The inspector reviewed past events and determined that none were similar to this event within the last two years.

Plant operation in Mode 3 with the four main steam line break protection channels inoperable is contrary to the requirements of Technical Specification 3.3.2. No violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B of 10 CFR 2, Appendix C, the violation was identified by the licensee; it was classified as a Severity Level IV; it was not reasonably expected to have been prevented by the corrective actions for a previous violation; and, the licensee corrective actions taken or planned were appropriate and comprehensive **(NCV 50-213/93-12-02)**.

2.6 Plant Startup

The inspector reviewed activities in progress during the period from July 10-19, to restart the plant after the refueling and maintenance outage. The objective of the review was to verify that plant procedures were followed and that prerequisite conditions and surveillances were completed as required to support the startup. Procedures used for this review included NOP 2.1-1, "Startup From Cold Shutdown to Hot Standby," NOP 2.1-2, "Reactor Startup," and NOP 2.1-8, "Nuclear Instrumentation Short Form." The inspection findings were as follows:

(1) The prerequisite conditions for startup were met. Procedures for startup and system operation were followed and appropriately used by plant operators. Safety systems were available as required by the technical specifications and the existing plant conditions. Reactor operation was controlled in a safe and orderly manner.

(2) The inspector verified, by direct observation of control room panel indications, that normal and emergency systems needed to support plant operation were operable and/or in standby service. Technical specification requirements for nuclear instrumentation, emergency core cooling systems, containment conditions, effluent monitoring instrumentation, reactor protection and emergency power systems were satisfied. The inspector verified that plant operating parameters were normal for the condition.

(3) Shift staffing complied with administrative requirements and was sufficient to support the evolutions in progress. Operators and supervisors were cognizant of plant conditions and observed startup activities. Support staff and supervisory personnel were readily available to support the operators; their presence did not adversely affect a professional working environment in the control room. Control and coordination of operating crew activities by supervisory personnel were good. There was good coordination between operations and reactor engineering personnel.

In summary, the inspector determined the plant heatup and the approach to criticality were completed in a controlled and deliberate manner by the operators. There were no schedular pressures apparent on plant operating personnel. The approach to critical on the new core was started at 6:36 p.m., on July 17. The reactor was critical for the first time for Cycle 18 operations at 3:55 a.m., on July 18. There was good regard for adherence to plant procedures.

2.7 Reactor Trip

A reactor trip occurred at 2:47 p.m., on July 19, 1993, due to the inadvertent generation of a source range (SR) high startup rate (SUR) trip signal. The reactor was critical at the time with a power of 4.0 X 10-2 on the wide range, which is just below the point of adding nuclear heat. The scram occurred while plant operators were testing the nuclear instrumentation in accordance with Normal Operating Procedure (NOP) 2.1-8, "Nuclear Instrumentation Short Form." The plant responded as expected following the trip and the plant transient was minimal.

The scram occurred due to an error by the operator while performing Step 6.2.1 of NOP 2.1-8. The operator had pressed and released the "calibrate" switch as required to check wide range channel 1 (WR1) indication and trip signals. The operator failed to reset the WR1 trips upon completion of the step as required, which left a SR high SUR rate trip in effect. When the operator depressed the "calibrate" switch to perform Step 6.2.2 on WR2, the simulated hi SUR signal completed the 2-out-of-4 logic needed to cause a reactor trip. The reactor operator allowed himself to be distracted while performing the procedure by going behind the panel to seek an I&C Technician in the middle of calibration.

The inspector reviewed the plant status following the scram and verified from control board indications that reactor and plant conditions were as expected. The inspector also reviewed the licensee actions in response to the event, including the meeting of the plant operations review committee (PORC) convened at 4:00 p.m., to evaluate the post trip review. The licensee counselled the operator involved. While no procedure inadequacies were identified, the licensee revised NOP 2.1-8 to add an additional caution statement at the start of each check of a nuclear instrumentation channel. The statement reiterated the requirement of precaution 5.3 for the operator to ensure that no trips are present before pressing the "calibrate" switch. The inspector had no further questions regarding the event, or the licensee's followup actions.

3.0 MAINTENANCE (61726, 62703 and 71707)

3.1 Maintenance Observation

The inspectors observed various corrective and preventive maintenance activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspectors also verified appropriate quality services division (QSD) involvement, appropriate use of safety tags, proper equipment alignment and use of jumpers, adequate radiological and fire prevention controls, appropriate personnel qualifications, and adequate post-maintenance testing. Portions of activities that were reviewed included:

- AWO 93-4941, Flow Instrument Sensing Line Leak Check
- AWO 93-2272, Modernization of Feedwater Control System
- ACP 1.0-6, Troubleshoot MCC 5 ABT
- AWO 93-9372, MCC 5 Inspection
- AWO 93-9373, MCC 5 Breaker 11C Inspection
- AWO 93-9371, MCC 5 Breaker 9C Inspection
- AWO 93-9781, Bus 5/6 Compartment Inspection
- PMP 9.5-192, Disconnection & Reconnection of Electrical Equipment

The inspector witnessed the conduct of several inspections and maintenance activities during the period that were part of the licensee's followup actions in response to the failure of MCC 5 testing on June 27, 1993. Maintenance activities were performed by both CYAPCo maintenance personnel and Generation Test Services (GTS) personnel. The maintenance, systems engineering and GTS personnel were very knowledgeable of the equipment and systems under test or inspection for all activities reviewed. The maintenance activities were performed in a professional and deliberate manner so as to carefully inspect the as-found conditions, and to record equipment status and performance accurately as part of the MCC 5 root cause investigation. The inspector noted personnel were very knowledgeable of the administrative controls, and followed them well. No inadequacies were identified.

- AWO CY 93 09577, Replacement of HMCP Breaker for CH-MOV-257

On July 7, the inspector observed maintenance electricians perform a one-for-one replacement of a 480 volt Westinghouse Type HMCP breaker. The breaker was replaced to increase its instantaneous overcurrent trip setting from 13.8 amps to 30 amps. Report detail 4.2 documents the purpose for the breaker replacement.

The inspector confirmed the appropriate breaker setting in comparison with setpoint change request (SCR) 93-038. The electricians adhered to proper torque valves for the power lead fasteners, independently verified lifted leads, and observed personnel safety requirements during the removal and installation of the breaker from the associate motor control center.

- AWO CY 93 09501, Inverter Troubleshooting

On July 6, the inspector observed maintenance electricians perform troubleshooting on the "D" vital inverter. The job description was to replace inverter control board PC1. The inspector noted good independent verification and care by electricians to remove the integrated circuit card. The post-maintenance test was successful. The inverter operated satisfactorily following maintenance. The inverter control board was returned back to the manufacturer for failure analysis.

- AWO 93-10282, Auxiliary Feedwater Degraded Hoses

The inspector reviewed maintenance activities under AWO 93-10282 to investigate and repair a hydraulic hose on the "B" auxiliary feedwater (AFW) pump. The supply hose from the pump skid to the steam admission valve failed during a system test at 10:15 a.m., on July 18, 1993. The plant was in operational Mode 2 at the time. Plant operators entered Technical Specification 3.7.1.2 pending completion of repairs.

CYAPCo determined that the supply hose failed due to a mechanical failure of the braid material. The damaged hose was replaced with like material from plant stores. Plant engineering evaluated the failed hose section because of concerns that this failure was similar to a chemical induced failure noted previously on the same system (reference PIR 92-178 and NRC Inspection 92-20). CYAPCo determined that chemical attack was not a factor in the present failure.

The inspector reviewed the failed hose section and concurred with the licensee's determination. The "B" AFW system was restored to service at 8:00 p.m., on July 18. No inadequacies were identified.

3.2 High Pressure Safety Injection Pump Deficiencies

The inspection purpose was to review CYAPCo's root cause analysis for the high pressure safety injection pump abnormal thrust bearing wear, and the long-term operability evaluation of the inadequate thrust bearing oil level indications. The inspection was follow-up to the review described in Report 50-213/93-08.

The licensee completed a formal root cause analysis of abnormal thrust bearing wear on the high pressure safety injection (HPSI) pumps on July 7. The root cause analysis was completed prior to entry in operational Mode 3 for which operability of the pumps is required pursuant to TS 3.5.1.a. The analysis was performed by maintenance engineering with assistance from the system engineer.

The licensee's root cause analysis concluded that accelerated thrust bearing wear found in the HPSI pumps was a result of various factors that included operating the pumps on recirculation flow for extended periods of time, equipment related causes, and human performance errors. The recirculation flow is 32 gpm, or approximately 2.4% of full rated flow for each of the pumps. The pumps are subjected to monthly and quarterly surveillances where the flowrate is through the recirculation pathway. Previously, the recirculation flowrate was deemed acceptable by the licensee, based solely on thermal rise across the pump. Recently, the pump vendor (Ingersoll-Dresser) recommended a continuous operation recirculation flow for the pump of 375 gpm. The accelerated wear on the pump's thrust bearings is based on large thrust during recirculation. The inner race of the ball bearings are expected to take a large portion of the thrust, due to the pump's balance drum not being designed to limit the thrust during low flow conditions.

NRC Information Notice (IN) 89-08, "Pump Damage Caused by Low-Flow Operation," documented two industry events where pump damage resulted by operating at flows significantly below their design flow rates. The notice stated that pumps had to be disassembled before damage to the pump internals could be seen. Routine pump surveillance tests provided by the inservice test programs may not be capable of detecting early component degradation. The Connecticut Yankee HPSI pumps performed in a manner similar to the experience documented in IN 89-08 since the inservice testing during the last operating cycle did not identify abnormal pump conditions (reference NRC Inspection Report 50-213/93-08).

On July 7, CYAPCo concluded that both HPSI pumps were operable with their current 32 gpm recirculation flow. The conclusion was based on tests performed on July 4 and July 5, under authorized work order (AWO) CY 93 08928. The testing varied the flow of the HPSI pumps between 1,300 gpm to 32 gpm. The licensee monitored the following parameters at the various flowrates: suction and discharge pressure, suction and discharge temperature, thrust and radial bearing temperatures, vibration data, and bearing noise level. All parameters were within the acceptance criteria of the vendor and inservice test program. The licensee also used a pump vendor evaluation formula for expected maintenance periods based on operation of the pump and the flowrate. The formula concluded that the pumps could run for 33 hours at minimum flowrate (32 gpm) prior to servicing. During last operating cycle the pumps ran for approximately four hours at minimum flow. Licensee engineering is considering a proposed modification to increase the minimum recirculation flowrate of the HPSI pumps for equipment preservation.

The licensee determined that equipment related causes for the abnormal wear were the low oil level in the thrust bearing sump, lubricant viscosity, incorrect bearing type on the "B" HPSI pump, a dirty oil sump, and the frequency of lube oil sampling. The equipment related causes were identified during a scheduled overhaul of the "B" HPSI pump. The low oil level in the trust bearing sump was documented previously in NRC report 50-213/93-08. The oil viscosity was incorrect based on licensee discussions with the bearing vendor (SKF). Previously the type of oil used for the pump was based on the recommendation from the pump vendor. The bearing vendor recommended a higher viscous oil. The licensee processed replacement item evaluation (RIE) form PEG-CYOE-93-158 to replace the type of oil for the pumps from Mobil Model DTE 797 to Mobil SHC 626. The inspector reviewed the RIE technical justification and verified that the oil was changed in both HPSI pumps.

CYAPCo also identified that the wrong roller bearings were used in the "B" HPSI pump. The bearing removed from the "B" HPSI was model FAG 7411 BUO. This bearing is a preloaded angular contact ball bearing. The correct bearing is a SKF 7411 BMG with axial clearance built into the bearing as recommended by the pump vendor. The cause for installing the wrong bearing in the "B" HPSI pump was traced to a 1988 licensee effort to update the bill of materials list. The update effort listed the wrong model number of the bearing for the HPSI pumps. CYAPCo corrective actions included replacing the bearings and adding the correct bearing model number to the HPSI pump bill of materials list.

The dirty oil sump was cleaned and a proposed revision to PMP 9.5-6, "P-15-1A & 1B HPSI Pump Motors Preventative Maintenance," will require the oil sump be flushed prior to adding new oil. The frequency of oil sampling was changed from once per refueling to quarterly. The quarterly oil sample will be added to the scheduled inservice test surveillance.

Licensee identified human performance issues related to the written communication for the wrong bearing type for the "B" HPSI pump, inadequate procedural steps for flushing the oil sump in PMP 9.5-6, the incorrect verbal communication from the pump vendor on the type of lubricating oil, and inadequate root cause analysis for past bearing oil analysis of the HPSI pumps. The licensee concluded that past root cause analyses of dirty oil in the HPSI pumps was incomplete, since the review did not include an evaluation of bearing model, oil acceptability, and the adequacy of recirculation flow. As corrective action, the licensee recommended additional root cause training for personnel in the maintenance department.

Conclusion

The inspector considers the licensee's root cause determination for the HPSI pump abnormal bearing wear to be extensive. The licensee identified various maintenance program deficiencies for the HPSI pumps. The inspector's assessment is that the HPSI pumps are operable and capable of providing their intended safety function. Unresolved item 50-213/93-08-01 was opened to follow this operability issue. However, a majority of the proposed licensee corrective actions were not complete at the end of the inspection period. The inspector considers unresolved item 93-08-01 still open pending: update of the Bill of Material List, revision of PMP 9.5-6, the completion of root cause training for maintenance personnel, and the completion of licensee evaluations to modify the HPSI recirculation flow.

3.3 Surveillance Observation

The inspectors witnessed selected surveillance tests to determine whether: frequency and action statement requirements were satisfied; necessary equipment tagging was performed; test instrumentation was in calibration and properly used; testing was performed by qualified personnel; and, test results satisfied acceptance criteria or were properly dispositioned. Portions of activities associated with the following procedures were reviewed:

- SUR 5.2-38.1-4, Loop 1 (2,3,4) Steam Line Break Channel Calibration
- PMP 9.2-29, Safety Class Instrument Inspection
- ST 11.2-6, PDCR 1331, Modernize Feedwater Control, Integrated Test

The inspector had no further comments on these tests.

- SUR 5.1-18, Test of Train "A" SIAS with a Partial Loss of AC

The inspector witnessed the second performance of this test which was conducted on June 27, after the first test (on June 26) was aborted when a loss of offsite power event occurred. The inspector observed the shift briefing, and implementation of the surveillance from the control room. The test acceptance criteria were met; however, two components failed during the test. The "A" battery charger failed when power was restored, and the non-safety grade "B" closed cooling pump breaker tripped open. The license documented the component failures on Plant Information Report (PIR) 93-138. The inspector further observed corrective maintenance on the "A" battery charger to replace the rectifying diode under PDCR 1418, "Upgrade the "A" Battery charger Rectifying Diode." No deficiencies were observed during the corrective maintenance.

- SUR 5.1-19, Test of Train "B" SIAS with a Partial Loss of AC

The inspector witnessed the second performance of this test which was conducted on June 29, after the first test (on June 27) was aborted when MCC 5 failed to transfer as required. The inspection included: a review of the test procedure for technical adequacy; verification that selected prerequisites and precautions were satisfied and/or followed; a review of the conduct of the test, including the shift briefing, personnel assignments, and test implementation; direct inspector observation of the plant system responses to verify equipment responded as expected; and, verification that the results satisfied the acceptance criteria.

The shift briefing conducted at 1:20 p.m., was thorough covering the test sequence, the expected plant response, and the actions required by test personnel. The testing sequence was executed by the operators in a deliberate, well controlled manner. The Supervisory Control Room Operator maintained good command of test activities, and provided good communication and coordination with test personnel. The inspector noted good operator repeat back of commands while exercising plant equipment.

The inspector noted that plant equipment responded as expected in response to the simulated safety injection actuation signal and loss of normal power (LNP). The simulated LNP was initiated by the operators at 1:51 p.m., by opening bus 1-3 supply breaker 3991. The "B" emergency diesel generator (EDG) started and powered bus 9 and associated loads in less than 10 seconds. The inspector noted, in particular, that the automatic bus transfer of motor control center (MCC) 5 operated correctly, by first swapping the MCC to bus 5 when bus 6 was deenergized as part of the partial LNP, and then transferring back to bus 6 when the "B" electrical train was re-energized by the EDG. The inspector also observed an auxiliary operator perform the load shed checklist (Attachment 3, SUR 5.1-19) in the "A" switchgear room. All loads changed to their required state. No inadequacies were identified.

- SUR 5.7-31, Inservice Testing of Boric Acid and RWST Check Valves, BA-CV-320, 372, and 387

On July 9, the inspector observed a control room operator and an inservice inspection (ISI) technician perform Section 6.4. of SUR 5.7-31. The surveillance objective was to verify operability of metering pump suction check valve BA-CV-320. The inspector verified that the charging system line-up was properly implemented. The acceptance criteria for valve BA-CV-320 was satisfied.

- SUR 5.7-108, Containment Integrated Leak Rate Test

The containment integrated leak rate test (ILRT) was performed at the end of the refueling outage to verify the structural integrity of the containment in accordance with Technical Specification 4.6.1.2.a. Inspection of this test included a review of the test methodologies with engineering personnel, a review of plant and containment system status, and a review of the leak inspections performed at the predefined pressure plateaus during the containment pressurization phase of the test.

Containment leakage was measured using the "total time" and "mass point" methodologies. The official results were those obtained from the "total time" method, since the test duration was less than 24 hours. The preliminary results reported by the licensee showed a total Type A leakage of 0.0919 weight percent (wt %) per day at the 95% confidence limit. This result compared favorably with the ILRT acceptance criteria of 0.135 wt % per day, which corresponds to the Technical Specification 3.6.1.2 limit of 0.75 La at a pressure (Pa) of 39.6 psig. No inadequacies were identified.

- SUR 5.2-4.5, Rack 1F/1R Periodic Surveillance

The inspector witnessed the performance of this test which was conducted to calibrate new instrumentation channels installed under plant design change record (PDCR) 1331. The new steam generator instrumentation is part of the licensee's improvements to the feedwater controls, which also include the use of Foxboro Spec 200 micro processor and analog equipment. The test was completed satisfactorily to calibrate the new equipment. Instrumentation and Control personnel were very knowledgeable of the design change, the equipment under test, and the test controls and requirements. No inadequacies were identified.

- ST 11.8-35, Functional Test of MCC 5 Transfer Scheme

This test was performed on July 5, to verify the satisfactory performance of the MCC 5 automatic bus transfer scheme. The test activities were part of the licensee investigation of the MCC 5 failure during testing on June 27, 1993. The testing on July 5, confirmed proper operation of the transfer scheme. The only anomaly identified was in the drop out of the slug on the 52X relay for breaker 9C. This anomaly became the focus of further investigation and is the subject of a 10 CFR Part 21 evaluation. Additional details on this topic are provided in NRC Inspection Report 50-213/93-80. No inadequacies were identified conduct of the July 5 tests.

3.4 Main Steam Safety Valve Failures

On July 13, at approximately 1:15 a.m., maintenance personnel reported to the control room operators that main steam safety valve (MS-SV-21) would not lift. The plant was in hot shutdown (Mode 3) and maintenance personnel were performing main steam safety valve tests pursuant to SUR 5.5-2, "Main Steam Safety Valve Surveillance Testing." The test was performed to verify acceptable valve operation following overhaul during the outage. The operators entered into Technical Specification Action Statement 3.7.1.1 for an inoperable safety valve, and continued testing the remaining main steam safety valves. At 1:38 a.m., safety valve MS-SV-11 failed to close for approximately four minutes after a successful lift. The licensee experienced a reactor coolant system cooldown of 12°F over this time frame. When the safety valve failed open, operators immediately secured the No. 1 reactor coolant pump, and shut the cold leg reactor coolant isolation valve. The cooldown was secured when the valve reseated at 1:42 a.m. Control room operators restarted the No. 1 reactor coolant pump. At 2:25 a.m., operators isolated the No. 2 reactor coolant loop and exited technical specification action statement 3.7.1.1. CYAPCo stopped main steam safety valve testing, and began an investigation into the cause of MS-SV-11 failure to reseat.

The inspector reviewed the licensee root cause determinations for the MS-SV-21 and MS-SV-11 failures, operator actions to cooldown reactor coolant loop No. 2, and technical specification adherence. The inspector also observed and reviewed main steam safety valve "as-left" testing.

CYAPCo determined that MS-SV-21 failed to lift because of an improper maintenance overhaul, and the lack of overhaul procedure guidance. The licensee identified during removal and disassembly of valve MS-SV-21 on July 15, that the valve stem was not fully engaged into the disc holder. The inspector observed this aspect during discussions with the job supervisor, and an unrelated overhaul of a spare main steam safety valve on July 14. For the valve to operate properly, the stem must fully insert through the disc holder threads, and have an axial clearance of approximately 3/8 inch. Failure to fully engage the valve stem into the disc holder results in additional compression on the valve spring, therefore resulting in a higher lift pressure. CYAPCo Maintenance Procedure PMP 9.5-210, "Main Steam Valve Preventative Maintenance," Step 6.9.2 instructs the mechanic to lubricate and thread the stem into the disc holder. No additional instructions are provided to check for axial clearance, or to ensure that the stem has been fully engaged into the disc holder.

In May 1993, during the shutdown for the refueling outage, the licensee successfully tested all main steam safety valves. During the refueling outage, the valve vendor (Crosby) personnel performed on-site overhaul of all sixteen main steam safety valves. CYAPCo discussions with the vendor personnel performing maintenance on this valve confirmed that he was aware of the stem to disc holder configuration; however, he did not verify proper engagement. The remaining fifteen valves were overhauled satisfactorily based on successful "as-left" test results pursuant to SUR 5.5-2.

The licensee concluded that MS-SV-11 failed to close due to a misaligned safety valve lifting device. The safety valve lifting device held the valve open, when the air pressure was reduced. Maintenance personnel removed the device and the valve reseated properly. The lifting device applies a known air pressure equal to a specific differential force on the valve spindle. The force on the valve spindle compresses the valve spring. The additive pressure from the valve lifting device and secondary steam generator pressure results in lifting the safety valve. The inspector learned that the safety valve lifting device undergoes no preventative maintenance. Additionally, SUR 5.5-2 for testing the safety valves describe how to install the device, yet no checks are taken to ensure that the device is aligned on top of the valve appropriately.

On July 14, the inspector observed control room operators implement Procedures NOP 2.4-3, "Shutdown of an Isolated Loop," and NOP 2.4-4, "Cooldown of an Isolated Loop." The inspector verified required temperature/pressure limits were being observed, appropriate system alignments, and adherence to Technical Specifications 3.1.1.2, "Shutdown Margin," 3.4.1.6, "Reactor Coolant System Loops," and 3.7.2., "Pressure and Temperatures Limits of Steam Generators." The inspector noted good interface within the operating crew, and control of maintenance work affecting the cooldown of the reactor coolant loop. No deficiencies were noted.

The inspector reviewed surveillance test results for the retest of failed main steam safety valves MS-SV-11 and MS-SV-21, and the "as-left" results of the remaining 14 valves. The test acceptance criteria is that the valve lifts within +/-1% of setpoint pressure during three consecutive tests. All valves tested satisfactorily and within the acceptance criteria.

The licensee's corrective action for the events were to revise Procedure PMP 9.5-210 to provide better guidance on the stem to disc holder installation; replace the disc holder on MS-SV-21; and, disassemble and refurbish the main steam safety valve test rig. The inspector confirmed that the last two items were completed at the end of the inspection period. Actions to revise Procedure PMP 9.5-210 were still in progress at the end of the period.

Conclusion

The licensee successfully identified the root cause for two valve malfunctions. MS-SV-21 failed to lift at its set pressure due to improper maintenance overhaul on the valve, and incomplete procedural steps to accomplish the overhaul. The failure of MS-SV-11 to reseat was due to a test device failure. Licensee corrective actions for the failures were adequate. Operator actions to isolate and cooldown the No. 2 reactor coolant loop to perform maintenance on MS-SV-21 were appropriate with good performance by the operating crew.

3.5 Loss of Vital Buses

On July 6, at approximately 1:12 a.m., the plant experienced a loss of two vital buses (C and D). The loss of the two vital buses resulted in an unplanned engineered safety feature (ESF) signal. The deenergized buses resulted in two of the four containment pressure transmitters to fail high, satisfying the two-out-of-four logic, and resulting in a high containment pressure (HCP) ESF signal. CYAPCo reported the event at 2:26 a.m., pursuant to 10 CFR 50.72 (b)(2)(ii) as a engineered safety features actuation. At the time of the event, the unit was in a cold shutdown condition. The shift supervisor verified that a HCP signal had occurred because the component cooling to drain cooler containment isolation valve closed, and the containment air recirculation fan dampers had realigned. Both vital buses "C" and "D" were lost for approximately 14 minutes. The control room operators realigned the vital buses to be supplied from the "C" inverter pursuant to AOP 3.2-15, "Loss of Vital Inverter."

The loss of vital buses occurred during the performance of PMP 9.1-35, "Local Load Testing of EG2B." The objective of the procedure was to verify that emergency diesel generator "2B" (EG2B) can be locally controlled and loaded onto 4160 volt bus 9, and to verify that bus 9 provides electrical power to 480 volt bus 11 and its associated equipment. The procedure functionally verifies the operator actions described in AOP 3.2-50, "Operations Outside the Control Room."

<u>Background</u>

The function of the vital 120 volt alternating current (AC) system is to provide a reliable source of regulated 120 volt power to instrumentation, control, and protection circuits necessary for plant safety. The system consists of four static inverters and six buses designated as "A", "B", "C", "C1", "D" and "D1". Vital inverters "C" and "D" receive electrical power from direct current (DC) bus "B" circuits 2 and 4, respectively. The inverters then feed buses "C1" and "D1", respectively. Buses "C1" and "D1" then feed buses "C" and "D", respectively. The bypass power supply to C1 and D1 120 volt vital buses are supplied by transformed 480 volt AC motor control center (MCC)-12 through a sola constant voltage transformer. The output of the transformer is supplied to a static switch, which determines whether the vital inverter or the bypass supply will supply the C1 and D1 distribution panels. The static switch is designed to reconnect the load from the inverter to the bypass source in the event of inverter malfunction or overload.

At approximately 12:37 a.m., control room operators performed Step 6.5.7. of PMP 9.1-35. Step 6.5.7. deenergizes 480 volt bus 11 from offsite power. At this time, operators noted a loss of vital buses "D" and "D1". The control room operating shift cross-connected the "D" vital buses with the "C" vital buses and continued with PMP 9.1-35. At approximately 1:12 a.m., operators performed Step 6.10.1 which secures EG2B and deenergizes 480 volt bus 11. At that time both vital buses were deenergized. The above actions were not expected during the performance of PMP 9.1-35. The procedure results in a momentary loss of 480 volt bus 11 which in turn powers MCC-12. The loss of MCC-12 would result in a momentary loss of the bypass power to the vital buses. The inverters were expected to supply power to the vital buses during the performance of PMP 9.1-35.

The July 6 test was the second attempt to perform Procedure PMP 9.1-35. On July 2, the licensee terminated from the test when the "D" vital inverter DC input supply breaker tripped when 480 volt bus 11 deenergized. The licensee initiated plant information report (PIR) 93-146 to document the event and initiate corrective actions. The licensee corrective action between July 2 and July 6, was to verify the DC input breaker undervoltage trip setpoint. The licensee identified that the "as-found" undervoltage drop-out for the DC input breaker to inverter "D" was at 120 volts DC. The trip setpoint should be 105 volts DC. The setpoint was readjusted on July 4, to 104.48 volts DC. CYAPCo believed that the "as-found" undervoltage setpoint resulted in the input breaker tripping on July 2. When 480 volt bus 11 is deenergized, this results in a loss of the associated "B" battery charger. Loss of the battery charger results in reductions of the DC bus "B" terminal voltage from approximately 132 volts to 120 volts, due to the station battery supplying the DC bus.

Inspection Results

The inspector evaluated the event sequence and operator responses, CYAPCo root cause determinations and corrective actions, maintenance troubleshooting activities, and the inverter preventative maintenance program. In the review of event details, the inspector verified that all applicable technical specification actions statements were adhered to. During the performance of PMP 9.1-35, the operators entered into TS 3.4.1.4.2.9. when both residual heat removal loops were not operable. After the loss of both vital buses, operators entered into the requirements for operable shutdown margin monitors (reference: TS 3.3.3.9). The inspector did not identify any other requirements applicable to the event for which required compensatory measures had to be established.

The inspector discussed with the shift supervisor the basis for continuing PMP 9.1-35 after loss of "D" vital bus. The shift supervisor felt it was appropriate to cross-connect loads from bus D and D1 to buses C and C1 since there was no apparent deficiency with the "C" inverter. The operator used AOP 3.2-15 as a means to accomplish the transfer of loads. The shift supervisor felt that conditions for the vital AC system had stabilized, and decided to continue with PMP 9.1-35. The shift supervisor had been aware of the unacceptable July 2, performance of PMP 9.1-35 and was under the impression that the cause of the equipment failure had been identified and corrected. The supervisor felt no outage schedule "pressure" to complete the procedure.

CYAPCo did not identify a specific root cause for the failure of inverter "D" and "C". However, during troubleshooting activities on July 4, the licensee identified that the instantaneous overcurrent setpoint for both inverter alternating current (AC) output breakers had resulted in inadvertent transfers to the backup supply. The AC overcurrent condition results in automatic transfer from the primary source (i.e. inverter) to the backup source. The instantaneous overcurrent setpoint had been set at 130% of rated current. The vendor (NUTHERM) recommends a setpoint above which nuisance trips do not occur. The overcurrent setpoint is based on peak current value and not the root mean square value as in long-term overcurrent protection. CYAPCo processed a setpoint change request (SCR) 93-44 to change inverter "C" and "D" overcurrent transfer setpoints to 160% of rated current. The basis for the change to allow one inverter to carry both vital buses. The inspector believes that this could be a probable cause to the inverter failure, since a large current transient over a short time interval could result in transfer to the back-up. During the performance of PMP 9.1-35, the backup supply is deenergized.

CYAPCo also processed a change to Surveillance Procedure SUR 5.1-153A, "AC and DC Distribution Normal Configuration," to verify that the auto transfer switches for both inverters were ON. The auto transfer switch previously was maintained in the OFF position. The auto transfer switch controls the automatic transfer from MCC-12 to the inverter after DC power is regained and/or renormalized. The circuit initiated a 45 second time delay, and retransfers back to the inverter (DC supply) once the condition for the transfer (i.e., AC instantaneous overcurrent) clears.

The inspector observed maintenance electricians perform AWO 93-09501. The work activity removed and replaced the inverter control card for the "D" inverter. The licensee's preliminary visual examination of the integrated circuit card determined that a power reduction resistor had opened allowing for an unregulated 32 volt DC supply to the card. CYAPCo provided the inverter control card to the vendor for destructive failure analysis. In addition to replacement of the inverter control card, CYAPCo performed recommended vendor checks on the inverters. The checks included phase orientation, frequency, and breaker undervoltage trip verification.

On July 7, CYAPCo approved and implemented special test (ST) 11.7-127, "Test of "C" and "D" Inverters." The test was performed after replacement of the inverter control card on the "D" inverter, the implementation of SCR 93-44, and the placement of the auto transfer switch in the ON position. The purpose of the test was to demonstrate that one inverter (C or D) could supply uninterrupted power to both vital buses "C" and "D" during the loss and restoration of MCC-12. The test demonstrated successful operation of both the "C" and "D" inverters. Report detail 2.5 discusses an event unrelated to inverter performance that occurred during ST 11.7-127. The licensee restored the inverters to an operable status on July 7.

The inverter preventative maintenance program was governed by PMP 9.5-179, "C & D Inverter Maintenance." The program was to visually inspect and clean the internals of the inverters at a refueling outage frequency. Procedurally, the verification of the DC input breaker undervoltage trip setpoint was based on job supervisor direction without any detailed periodicity. The licensee was evaluating additional preventative maintenance objectives for the vital inverters at the end of the inspection period.

Conclusions

No specific root cause was identified by the licensee on failure of the "C" and "D" vital inverters. Probable causes such as AC breaker instantaneous current setpoints, and a fault on the inverter control card could explain the event. The inverters were tested successfully under ST 11.7-127. Operator response to the loss of vital buses was appropriate. License conditions and required reports (i.e., 10 CFR 50.72) were implemented appropriately.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

4.1 Motor Operated Valve Test Procedures

The inspectors reviewed the licensee's dynamic test procedures for motor operated valves (MOVs). Discussions were held between the licensee and NRC to address Generic Letter 89-10 program expectations. These expectations included assumptions used in support of design bases and requirements for dynamic test procedures to determine MOV capabilities under design basis accident conditions. An internal NRC memorandum, dated April 30, 1993, which provides guidance for licensee MOV program reviews consistent with the generic letter, was discussed in detail with regard to the licensee's testing program for the valves in the program.

Review of CY Special Test Procedure ST 11.7-99, "Dynamic Testing of RHR to Charging System Cross Connect MOV RH-MOV-33 A and B," and associated Temporary Procedure Change (TPC) 93-402 revealed the need for test procedure enhancements for determining torque or motor capability, load sensitive behavior (rate-of-loading), diagnostic test equipment inaccuracies, open stroke requirements in addition to the determined closed safety function stroke requirements, and evaluation of test results when test parameters achieved are less than 80% of expected design basis conditions. Following these discussions, the licensee issued a draft memorandum, dated June 17, 1993, (SE -93-615) to modify MOV dynamic test procedures in the above areas.

The inspectors reviewed Procedure ST 11.7-115, "Dynamic Testing of Core Deluge Valves SI-MOV-871 A and B and 873," and verified that these procedures had been revised to incorporate the information provided in SE-93-615. However, further review and discussions by the NRC and licensee identified additional areas needing enhancement within the procedure and the procedure attachments to assure test validity and proper margin evaluation. The inspectors verified that the procedure enhancements had been completed as of June 30, 1993.

The inspectors reviewed the licensee's MOV Program Instruction (PI) Number 9, "Determination of Stem Thrust Requirements," and noted that a stem friction coefficient of 0.15 was specified for thrust calculations. However, the inspectors noted that the licensee used significantly lower stem friction coefficients (approximately 0.13) for five valves. NRC staff position specifies a stem friction coefficient of 0.2 for thrust calculations and requires the licensee to develop a plan to justify the use of lower stem friction coefficients based on valve specific test information. The licensee stated that the lower stem friction coefficients were used for the interim after case-by-case evaluations were made. This item is unresolved pending licensee development of a programmatic plan to validate the use of stem friction coefficient values in thrust calculations **(Unresolved Item 50-213/93-12-03)**.

4.2 Molded Case Circuit Breaker Replacements

The inspection scope was to evaluate CYAPCo's actions with respect to molded-case circuit breaker replacements pursuant to plant modification PDCR 1336, "CY-Low Voltage Molded Case Circuit Breaker Replacement - Phase II." The inspection was further prompted by various plant information reports (PIRs) during the refueling outage documenting breakers found in a tripped condition. The review considered the history of 480 volt breaker replacements, design changes in PDCR 1336, setpoint changes, and observation of maintenance activities.

In 1987, the contractor (Bechtel) installed Westinghouse HMCP breakers in motor control centers (MCC's)-12 and 13 in the new switchgear building modification. In 1988 and 1993, CYAPCo implemented two plant modifications to remove the original supplied 480 volt AC molded-circuit breakers (Type HFA) on MCC 5.

CYAPCo documented four PIRs since May 1993, concerning 480 volt molded-case circuit breakers found in a tripped condition. Two of the PIRs occurred during partial loss of offsite power and MCC 5 testing (refer to Inspection Report 50-213/93-80). During the partial loss of offsite power surveillance on June 26, operators attempted to close two safety injection motor-operated valves (SI-MOV-861A and SI-MOV-861B) with a safety injection signal present. The valve breakers tripped off. PIR 93-151, dated July 7, documented that four breakers were found tripped after testing of automatic bus transfer scheme for motor control center (MCC)-5. The four breakers were for two service water valves (SW-MOV-1 and SW-MOV-2), charging suction valve (CH-MOV-257), and the "B" control air compressor. All of the breakers are located on MCC 5.

The safety injection and charging system motor-operated valves and the "B" control air compressor were subject to breaker replacement as part of PDCR 1336. PDCR 1336 replaced original Westinghouse (W) type HFA beakers with W circuit protection breaker (type HMCP). The basis for the replacement was a conclusion by the licensee that HMCP breakers provide adjustable, lower instantaneous trip setpoints than the HFA type, and in doing so provide improved motor protection.

For the June 26 event, NUSCo engineering determined that the overcurrent condition was a result of "plugging". Plugging refers to taking a motor control switch to a position opposite the automatic signal (i.e., safety injection) with the automatic signal still present to the valve. Plugging is an operation where the motor is being commanded to operate in one direction but when the control signal is removed, a pre-existing signal causes the load to become instantaneously energized. The effects of jogging (throttling a motor-operated valve) and plugging can result from either manual or automatic circuit switching whereby the impressed inrush current across the motor terminals may reach twice the locked rotor current (LRC). CYAPCo corrective actions were to process a setpoint change request (SCR) 93-037. Operations department personnel develop a list of all MOV's that could be jogged or plugged during the performance of the EOPs. The SCR changed the HMCP breaker trip setpoints from 2.1 to 2.3 times the locked rotor current (LRC) for the valves. For the July 7 event, NUSCo engineering determined that a voltage transient on MCC 5 bus transfer from preferred source of 480 V bus 6 could theoretically result in twice the bus voltage. CYAPCo corrective actions were to adjust the MCC 5 breakers to instantaneous current setting of 4.6 X LRC (SCR 93-038). The inspector observed various PORC meeting approving the SCR's and design changes, and observed AWO CY 9309577 on July 7 (report detail 3.1).

The inspector questioned NUSCo engineering whether an operability issue or a reportable condition existed during past plant operation with the previous ABT design for MCC 5. During the week of July 19th, the licensee initiated a REF to review the MCC 5 transfer with breakers tripping unexpectedly. The preliminary determination was that MCC 5 remained operable and that the condition was not reportable since the automatic bus transfer selector switch was in the position aligned to bus 5 between 1988 and 1993, during non-surveillance intervals. However, the review was on-going at the end of the period. CYAPCo was developing a root cause evaluation on the use of HMCP beakers for future modifications. The inspector will review this in future inspections.

4.3 Cycle 18 Startup Testing Program

The startup test program was conducted according to licensee's Procedure ST 11.3-3, "PDCR 1399 Preoperational Testing." The test sequence outlined the steps in the test program, initial conditions and prerequisites, specified calibration, and surveillance procedures at appropriate points in the sequence. The low-power physics testing program was conducted on July 13-19, 1993. Initial criticality of Haddam Neck Station, Cycle 18, was achieved at 3:55 a.m., on July 18, 1993.

The inspector verified that the approach to critically, inverse multiplication plots, and boron concentration surveillances were performed in accordance with the licensee's procedures and technical specifications (TS). The inspector independently verified that the test program acceptance criteria were obtained from Haddam Neck Plant Technical Specification, Cycle 18 Nuclear Design Report, and American National Standard ANSI/ANS 19.6.1, 1985, "Reload Startup Physics Tests for Pressurized Water Reactors."

The inspector witnessed the following of low-power physics tests:

Parameters	Measured Value	Criteria
Boron Concentration All rods out (ARO)	1809 PPM	1813 ± 50 PPM
Control Rod Worth (Total worth of banks A, B, & D)	5075.5 PCM	5075.5 ± 10%
Isothermal Temperature Coefficient (ARO)	1.124 PCM/°F	0.38 ± 2 PCM/°F
Control Rod Drop Times		
Rod # 34	2.03 seconds	≤ 2.45 seconds (1)
Rod # 35	2.01 seconds	≤ 2.45 seconds (1)
Rod # 10	2.04 seconds	≤ 2.50 seconds (2)
Rod # 11	2.01 seconds	≤ 2.50 seconds (2)

(1) Three reactor coolant pumps in operation
(2) Four reactor coolant pumps in operation

The reactor engineers conducting the startup physics tests were knowledgeable of test procedure requirements. All test procedures were detailed, well organized, and of high quality. The calculations were well documented on calculation data sheets. The combination of quality test procedures and knowledgeable test personnel resulted in a safe, efficient, low-power startup test program.

The inspector observed that Quality Service Department (QSD) personnel provided around-the-clock coverage for startup testing activities. The inspector observed that QSD staff provided timely communications to the test staff. In one instance, the QSD staff discussed procedure step clarification with the test engineer. The QSD coverage of the startup testing provided a positive contribution to the startup test program at Haddam Neck.

5.0 PLANT SUPPORT (40500, 71707, 90712, and 92701)

5.1 Radiological Controls

During routine inspections of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's radiological controls program. The inspector reviewed utilization and compliance with radiation work permits (RWPs) to ensure that detailed descriptions of radiological conditions were provided and that personnel adhered to RWP requirements. The inspectors observed controls of access to various radiologically controlled areas and the use of personnel monitors and frisking methods upon exit from those areas. The inspector verified posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were in accordance with licensee procedures. The inspector determined that health physics technician control and monitoring of these activities were good.

5.2 Plant Operations Review Committee

The inspectors attended Plant Operations Review Committee meetings on June 30, July 7, and July 13. Technical Specification 6.5.1 requirements for required member attendance were verified. The meeting agendas included procedural changes, proposed changes to the Technical Specifications, Plant Design Change Records, and minutes from previous meetings. PORC meetings were characterized by frank discussions as evident by the July 7, PORC meeting discussing operational issues and resolution prior to entry into operational Mode 4. The committee closely monitored and evaluated plant performance and conducted a self-assessment of plant activities. The committee discussions and reviews following the reactor trip on July 19, were thorough and probing to identify contributing causes and to recommend followup actions.

5.3 Review of Written Reports

Periodic and Licensee Event Reports (LERs) were reviewed for clarity, validity, accuracy of the root cause and safety significance description, and adequacy of corrective action. The inspectors determined whether further information was required. The inspectors also verified that the reporting requirements of 10 CFR 50.73 and Technical Specification 6.9 had been met. The following reports were reviewed:

- <u>Haddam Neck Steam Generator Examination Category C-3 Special Report</u>

The inspector concluded that CYAPCo provided the required information and proposed actions pursuant to Technical Specification 4.4.5.5.(c) and 6.9.2.

LER 93-006-00, Emergency Diesel Generator Failure From Diode Assembly Failure

This event documented an event where a single cause or condition resulted in independent trains to be potentially inoperable. Specifically, two diodes failed on the generator field excitation cabinet as a result of a lack of air flow from inoperable excitation cabinet exhaust fans. A majority of the specifics associated with this event were documented in NRC Inspection Report 50-213/93-08.

The inspector verified the short-term corrective actions. Specifically, the licensee stated that they 1) replaced the affected diodes for both emergency diesel generators; 2) provided an air stop between the generator and excitation cabinet; and, 3) periodically verify excitation cabinet fan operation. The inspector noted that the diodes were replaced under AWO's CY 93-06744 and CY 93-7471 for the "A" and "B" emergency diesel generator. The air stop was installed on June 18 and June 29, under AWO's CY 93-08418 and CY 93-08771, respectively. Periodic verification of excitation cabinet fan operation was incorporated in Surveillance Procedure SUR 5.1-0, "Steady State Operational Surveillance," Revision 18, to have the secondary auxiliary operator verify air flow every eight hours.

Licensee long-term actions included a modification to start the exhaust fan with diesel generator operation, and a programmatic review of the preventative maintenance programs associated with instrument and control cabinets. The licensee initiated engineering work request (EWR) 93-MS99 to evaluate the modification. The programmatic review is controlled under controlled routing 93-0628.

The inspector considers this LER closed.

LER 93-008-00, Steam Generator Eddy Current Testing Results Classified as Category C-3

The licensee reported the steam generator test results as required by the technical specification. Based on eddy current testing results, two of the four steam generators were in a C-3 category. A C-3 category is either 10% of the tubes inspected were degraded, or 1% of the tubes were defective. The total number of seam generator tubes taken out of service in the 4 steam generators was 39. The inspector verified that sufficient in-service tube margin exists in loss of coolant accident (LOCA) and non-LOCA safety analysis.

LER 93-004-00, Entry Into Technical Specification 3.0.3. Due to Inoperable Service Water Pumps

This report documented the entry into Technical Specifications 3.0.3 when operators placed two out of the four service water pumps in trip pullout (TPO) during surveillance testing. NRC review and assessment of the event was documented in report 50-213/93-08 (report detail 3.3.). NRC unresolved item 93-08-02 was open pending review of the effectiveness of licensee corrective actions for this event. The inspector considers review of LER 93-004-00 closed.

5.4 Security

During the weeks of May 10 and June 21, 1993, the inspector reviewed the licensee's weapons program and training program for newly hired security officers. Recently, the licensee started using new service weapons. An inspection of the armory found none of the previously used duty weapons.

During discussions with security force members (SFM), the inspector was informed of an incident involving personal weapon grips being removed from an assigned duty weapon. The inspector determined that the incident involved a SFM that due to health reasons, was no longer employed. The individual was absent for an extended period of time and not knowing if the individual would be returning to work, the grips were removed and the duty weapon reassigned. When the SFM returned to the site to claim his personnel property, the grips could not be located. The contractor assumed responsibility for the lost grips and made restitution. This was the only situation of this type brought to the attention of the inspector. The inspector determined by an inspection of the armory, review of records and procedures and discussions with licensee and contractor personnel, that weapons were being properly maintained, issued, and accounted for in accordance with established procedures.

The inspector performed an indepth review of the training program to include records of newly hired security personnel. During the review, the inspector noted that one newly hired armed officer apparently had difficulty performing certain duties. The officer received remedial training on two separate occasions. Subsequently, the officer elected to take a position as a watchperson. The inspector discussed this individual's case with the licensee and its contractor. When hired, the individual was immediately placed into the armed officer training program. Most security force members, upon hiring, enter the program as a watchperson and subsequently become an armed officer only after additional training and familiarization with the plant. The inspector advised the licensee that the armed officer training program should be evaluated to determine if it is adequate for a newly hired security officer. Based on discussions with the contractor training manager and interviews with security force members, the inspector determined that the training program satisfies the requirements of the training and qualification plan (T&Q) and that mechanisms are in place, e.g., on-the-job training (OJT), drills and response scenarios, to identify potential or actual weaknesses.

6.0 EXIT MEETINGS

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

In addition to the exit meeting for the resident inspection held on August 4, 1993, the following meetings were held for inspections conducted by Region I based inspectors.

Report No.	Inspection Dates	Reporting Inspector	Areas Inspected
50-213/93-80	6/30-7/9/93	Trapp	Augmented Inspection Team
50-213/93-11	6/21-6/25/93	McBrearty	In-service Inspection
50-213/93-14	7/19-7/23/93	Carrasco	Pipe Supports