U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No. 50-293/86-01 License: DPR-35

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: January 1 - February 17, 1986

Inspectors: M. McBride, Senior Resident Inspector
G. Meyer, Project Engineer

Approved by: L. E. Tripp 3/12/86
L. Tripp, Chief, Reactor Projects Section 3A Date

Summary: January 1 - February 17, 1986: Inspection Report 50-293/86-01

Areas Inspected: Routine resident inspection of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operation records, maintenance, surveillance, documents provided to the licensee, and reports to the NRC. Inspection hours totaled 128 hours.

Results: Two examples of one violation were identified (failure to follow procedural instructions for completing reactor Post Trip Review (PTR), Section 10, and failure to follow procedural instructions for logging disabled control room annunciators). In addition, a concern was identified regarding a lack of aggressiveness in repairing nonsafety equipment in the control room. Unresolved items involving cracking of a one-inch residual heat removal test line inside the drywell (Section 4.e); the installation of fuses versus metal links in motor control circuits (Section 5.e); the faulting of a 480 V a.c. safety bus during a cable repair (Section 5.k); and a repeated pressurization of residual heat removal system piping (Section 5.l) were also identified pending further NRC review of these matters.

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DETAILS

1. Persons Contacted

   N. Brosee, Maintenance Section Manager
   P. Mastrangelo, Chief Operating Engineer
   C. Mathis, Nuclear Operations Manager (Senior licensee manager present at exit meeting)
   J. McEachern, Resources Protection and Control Group Leader
   R. Sherry, Chief Maintenance Engineer (acting)
   T. Sowdon, Radiation Protection Section Manager

   The inspector also interviewed other licensee employees and contractors during the inspection, including members of the operations, maintenance, radiation protection, security, and technical staff.

2. Summary of Facility Activities

   At the start of the inspection period, January 1, 1986, the plant was at full power. The reactor was shutdown on January 3, for a three-day turbine generator maintenance outage. A low reactor water level scram occurred on January 6 during the subsequent startup, due to operator error. A second scram occurred on January 16, due to a spurious reactor high pressure signal. The reactor was restarted on January 18 and operated at power during the rest of the inspection period. Three Unusual Events were declared on January 4 and 9 and on February 14, 1986.

3. Licensee Action on Previous Inspection Findings

   (Closed) Unresolved Item (84-21-03). Ultrasonic test (UT) reports do not clearly specify acceptance or rejection status of a reviewer on the form. The licensee has modified UT test report forms in Quality Control Instruction 50.70, "Ultrasonic Examination - General Requirements", and Quality Control Instruction 50.71, "Ultrasonic Examination of Class 1, 2 and 3 Pressure Retaining Welds", to indicate acceptance or rejection by a responsible reviewer. The inspector had no further questions.

   (Open) Follow Item (84-28-01). Review evidence of poor control of nonconforming material, including an untagged nonconforming safety relief valve, a pipe gouge, and poor control of contractor Surveillance Inspection Reports (SIR). In response to this finding, the licensee contractor discontinued tracking items under the SIR system. The licensee stated that the contractor initiated Nonconformance Reports (NCR) and Failure and Malfunction Reports (F&MR), in place of the SIR's. The inspector reviewed documentation associated with the pipe gouge repair, including: the dispositioned G.E. NCR RS-003, the completed work traveler 84-400-033, and the liquid penetrant examination report of the pipe repair area.

   The inspector had no further questions regarding the use of SIR's and the repair of the pipe gouge. However, this item will remain open pending a programmatic review of the remaining issue; the control of nonconforming material in the station.

(Closed) Inspector Follow Item (293/85-28-01). Logging of containment pressure. The inspector had found that daily logging of containment pressure instruments on OPER 9 was inconsistent, in that the indicators were logged for the narrow range and the recorders were logged for the wide range, although both ranges had both indicators and recorders. On January 22, the inspector reviewed the logging of containment pressure on OPER 9 and found that Revision 60 of OPER 9 had corrected this oversight and that both indicators and recorders are being logged for both ranges.

4. Routine Periodic Inspections

a. Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and limiting conditions for operations (LCO's), instrumentation and recorder traces, control room annunciators, safety equipment operability, control room logs and other licensee documentation.

No unacceptable conditions were identified.

b. Systems Alignment Inspection

Operating confirmation was made of selected piping system trains. Major motor operated and manual valve positions for safety equipment were verified during routine checks of the control room. Valve power supply, breaker alignment, and safety equipment controller set points were also checked.

No items for further inspection were identified and no unacceptable conditions noted.

c. Biweekly Inspections

During plant tours, the inspector observed shift turnovers and checked: plant conditions, valve positioning and locking (where required), instrumentation lineup, radiological controls, security, safety, and general adherence to regulatory requirements. Plant housekeeping and cleanliness were evaluated.

d. Plant Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, codes and standards, proper QA/QC involvement, safety tag use, equipment alignment, jumper use, personnel qualifications, radiological controls for worker protection, fire protection, retest requirements, and reportability per Technical Specifications.

A list of reviewed items is included in Attachment 1 to this report.

-- On January 4, 1986, a leaking weld was noted in a one-inch test line near the MO-1001-68B check valve for the residual heat removal (RHR) system during a drywell inspection. A circumferential crack was identified in the heat-affected zone of a socket weld which attached test line to the "B" RHR injection line. This test line had not been replaced during the 1984 extended outage. The test line was located between the RHR check valve and the "B" reactor recirculation loop. The crack extended over approximately one half of the test line circumference.

The licensee removed the cracked section of pipe and shortened the test line to reduce the bending moment. The inspector discussed the cracked line with maintenance and engineering personnel who were evaluating the problem. No previous cracking has been observed in this test line. At the end of the inspection, the licensee had not completed its evaluation of the defect. This item will be unresolved, pending the completion of the evaluation (86-01-01).

-- On January 4, 1986 during a drywell walkdown of the Yarway reactor water level instrument reference legs, several defects in the instrument support brackets were observed. These problems included a missing pipe support, an out of position pipe support, a support that had pulled loose from the wall, and one support that had a broken base plate bolt. The licensee stated that a subsequent safety evaluation indicated that the support problems had not affected the operability of the water level instruments. The brackets were repaired prior to a subsequent reactor startup. At the exit interview, the licensee indicated that the supports were original plant equipment and that the affected Yarway reference legs were scheduled to be moved outside the drywell during the next refueling outage. The inspector had no further questions at this time.

e. Surveillance Testing

The inspector observed parts of tests to access performance in accordance with approved procedures and LCO's, test results (if completed), removal and restoration of equipment, and deficiency review and resolution.

A list of reviewed items is included in Attachment 1 to this report.

-- On January 4, 1986, two of eight main steam isolation valves (MSIV) failed to close within the time limits required by the technical specifications during a routine quarterly surveillance test, Procedure 8.7.4.4. The technical specifications require that the MSIV's close in 3 to 5 seconds. Valve AO-203-1B closed in 5.66 seconds and valve AO-203-2A gave no closed indication to the control room during the test.

The licensee declared both valves inoperable at the completion of the test. Fifteen minutes later, an unusual event was declared because a reactor shutdown was required by the technical specifica-

tions due to the loss of primary containment. A previously scheduled reactor shutdown had been in progress at the time of the test. The shutdown was continued, the reactor was placed in a cold condition, and the drywell was deinerted. The inspector reviewed maintenance and surveillance documentation and discussed the valve operator repairs with the maintenance staff.

The four-way air operated control valve for the AO-203-1B valve operator was subsequently replaced. This valve, American Valve Corporation model C5140-4H, had been replaced on this MSIV and one other MSIV at the start of the current operating cycle (NRC Inspection Report 50-293/85-03). At the exit meeting, the licensee indicated that the four-way valves for the remaining MSIV's would be overhauled during the upcoming refueling outage.

The closed position limit switch on valve AO-203-2A was found out of position and would not trip when the valve was actually closed. When the limit switch was repositioned, the valve time was found to close slightly fast (2.96 seconds versus the 3.00 second limit). The hydraulic dash pot for the valve was then adjusted and the valve closed within the acceptable time range.

No trends in valve closing times were noted in 1985 surveillance tests. The 1B valve typically closed between 4.5 and 5.0 seconds and the 2A valve closed between 3.0 and 3.4 seconds during routine quarterly surveillances. The licensee could not locate the test results from a quarterly test conducted in September 1985. The inspector had no further questions regarding the MSIV repairs at this time. However, this item will remain open pending a review of the September 1985 test results (86-01-02).

-- On January 13, 1986, the inspector witnessed a portion of the calibration of a water pressure indicating instrument on the "B" loop of the reactor building closed cooling water (RBCCW) system. The inspector verified that technicians were using a current version of Procedure 8.E.30 and verified that test equipment was recently calibrated. No deficiencies were identified.

-- On January 30, 1986, the inspector observed portions of a main steam line radiation monitor calibration, procedure 8.M.1-13.1. The technicians conducting the calibration followed the procedure closely and questioned their supervisor over procedure steps that were unclear. Maintenance personnel performing the surveillance were aware of the licensee's time restriction on removing this equipment from service (i.e., an instrument channel can not be removed from service for more than two hours for surveillance). The inspector verified that a current copy of the surveillance procedure was being used and had no further questions.

-- On January 21, 1986, the "D" salt service water pump discharge pressure entered the inservice test (IST) alert range during a routine surveillance test, no. 8.5.3.2. The total discharge head at shutoff during the surveillance was 148.3 ft. of water. The IST low alert limit was <153.3 ft. and the required action range was <148.0 ft. The inspector verified the discharge head calculation and reviewed previous IST data for the pump. The data showed a steady decline in pump discharge head during 1985.

The inspector noted that the IST data graphs were messy and difficult to read. Also, the acceptance criteria for the wrong salt service water pump was used on the IST analysis sheet. The differences in the discharge head acceptance range between the two pumps were small, i.e., 153.1 to 179.8 ft. was used instead of 153.3 to 180.6 ft. At the exit interview, the inspector recommended that the IST data be reviewed to see if better data presentation and organization would help avoid personnel errors. The licensee indicated that the previously planned modification of the IST data would be implemented in the near future. The acceptability of the IST data system will be reviewed during a future routine inspection.

The "D" salt service water pump was subsequently overhauled and returned to service. No subsequent problems with this pump were noted during the inspection period.

-- While watching the calibration of drywell pressure swtiches 10-PS-1001-83B and -83D under Procedure 8.M.2-2.1.5, the inspector noted that the two technicians performing the test did not have a copy of the procedure with them, although they used telephone communication with other people involved in the calibration who presumably had the procedure. The switches are located in the reactor building in a radiologically controlled area where shoe covers and gloves were required. The calibration was performed in a technically acceptable manner.

In discussions with Instrument and Controls (I&C) Supervisor, the inspector questioned the lack of the procedure at the calibration location. The I&C Supervisor stated that this practice was followed to reduce the possibility of contaminating the paperwork and has been used at the station as long as it has been operated. Further, he noted that the calibration procedure was generic for pressure switches and within the skill of the technicians.

The inspector agreed that reduction of contaminated waste was a desirable goal, but questioned whether lack of the procedure was necessary to achieve this goal. The inspector noted that the telephone communication unnecessarily increased the chance for error due to misunderstood numbers or directions and precluded the use of diagrams or sketches, which may have been helpful. Also, the lack of a procedure at the work location made the independent veri-

fications less meaningful, as they were signed off later based on the technician's recollection. The inspector stated that the improvements on the cleanliness of the plant may have made the practice unnecessary. The inspector stated that the practice was not a violation of regulatory requirements, but its potential for adversely affecting the safety of a plant would continue to be reviewed as part of the routine inspection program.

5. Review of Plant Events

a. Partial Isolation of the Reactor Cleanup System

On January 3, 1986 at 10:55 p.m., the inboard isolation valve for the feed line to the reactor water cleanup system closed. The licensee subsequently found that a fuse blew due to a failed coil in relay 16A-K65. This caused the relay to deenergize, generating an isolation signal which closed the cleanup valve. The relay, General Electric model CR120A, forms a portion of primary containment isolation logic and is designed to deenergize on a high cleanup system flow signal.

The inspector reviewed maintenance documentation and discussed the failure with maintenance personnel. Failures with this type of relay have not been previously noted. The relay coil was replaced and the system returned to the normal valve line up. The inspector had no further questions at this time.

b. Reactor Shutdown for Turbine Generator Maintenance and Subsequent Unusual Event

On January 3, 1986 at midnight, a reactor shutdown was initiated to start a short turbine maintenance outage. Vibration had previously increased in the No. 9 bearing of the main turbine generator and the licensee planned to dissassemble an associated rotor coupling. The reactor was placed in the cold condition and the drywell was deinerted during the outage. A startup was initiated three days later on January 6, 1986.

While the reactor was shutting down on January 4, 1986, two main steam isolation valves (MSIV) failed to close within the time period required by the technical specifications during a routine surveillance test. An unusual event was declared. The event was terminated later that day, after one valve was repaired and the steam line containing the second valve was isolated. The MSIV surveillance test and repairs are discussed in Section 4.e of this report.

The inspector identified no problems with the shutdown. The reactor startup is discussed further in the next section of this report.

c. Reactor Scram on Low Water Level due to Operator Error

On January 6, 1986 at 8:00 p.m., the reactor scrammed on low water level from about 10% power. A reactor startup was in progress at the time and control room operators did not act promptly enough to stabilize decreasing reactor water level. Specifically, with reactor water level decreasing the operators did not open feedwater block valves and transfer feedwater control from the manual startup regulating valve to a feedwater regulating valve in automatic control. The event was subsequently described in LER 86-001-00. The licensee indicated that the water level was difficult to control with the manual valve at that power range. As long term corrective action, the licensee plans to evaluate an automatic controller for the startup feedwater regulating valve.

Normal scram recovery procedures were used to stabilize the reactor. A reactor startup was reinitiated at 2:30 a.m. on January 7, 1986 and full power was reached on January 10, 1986. The startup was slowed because reactor water conductivity was slightly greater than the EPRI limit of 0.3 umho/cm. The inspector had no further questions regarding the startup.

d. Hydrogen Fire

On January 9, 1986 at 11:00 a.m., leaking hydrogen ignited during the replacement of a gas regulator in the hydrogen supply system for the main turbine generator. The fire was limited to an opening in one pipe at the onsite hydrogen storage facility. The facility was located outside the process buildings near the main security access gate. The licensee declared an unusual event at 11:20 a.m. on January 9, 1986. The event was terminated twenty minutes later after the fire was extinguished and a new regulator had been installed to halt gas flow. The local town fire department was summoned onsite and assisted the licensee fire brigade. The reactor was at 75% power. No fire damage was subsequently identified.

The hydrogen storage tanks were then blown down and a defective hydrogen block valve repaired. The inspector witnessed a portion of the initial regulator replacement. Licensee maintenance personnel indicated that hydrogen block valves have occasionally leaked in the past and have been replaced. At the exit meeting, the licensee indicated that the hydrogen supply system was going to be significantly upgraded in the near future in preparation for hydrogen injection into the reactor coolant system. The upgraded system will have block valves of improved design. The inspector reviewed the licensee fire investigation report and had no further questions at this time.

e. MO-1001-29A Inoperable

On January 15, 1986 at 4:40 p.m., a Nuclear Watch Engineer noted that no valve position indication lights in the control room were lit for a low pressure coolant injection (LPCI) system injection valve, MO-1001-

29A. A subsequent investigation found that a one-amp fuse had blown in the valve motor control circuit. The circuit was checked and no other problems were identified.

Station drawings indicated that a solid metal link should have been installed in the control circuit, rather than a fuse. The MO-1001-29B valve control circuit was also checked and a fuse was found instead of a metal link. An initial engineering review indicated that the fuses were acceptable. However, the licensee replaced fuses in both circuits with links, prior to declaring the valves operable.

In a related matter, on January 16, 1986, a safety-related 480V a.c. breaker was reported to be smoking. The breaker, B1521, controls ventilation fans in the intake structure. The fans are required to cool service water pumps in the summer. The licensee determined that a fault in the fan control circuit caused the motor control transformer to overheat and smoke. A metal link was installed in this control circuit instead of a fuse.

At the exit meeting, the licensee indicated that the corporate engineering staff was reviewing the basis for using metal links and fuses in motor control circuits. This item is unresolved pending the results of that evaluation (86-01-03).

f. SRO Medical Review

On January 15, 1986, the inspector was informed that an individual holding a senior reactor operator (SRO) license had been restricted from duty since December, 1985 for medical reasons. The individual did not normally conduct licensed duties at the station. The inspector discussed the requirement in 10 CFR 55.41 to report medical conditions affecting licensed individuals with the Station Manager. The inspector also expressed concern that other licensed individuals not routinely conducting licensed activities might not remember the medical reporting requirement.

Subsequently, the licensee contacted NRC Region I via telephone and discussed the ongoing medical review of the individual. At the exit meeting, the licensee indicated that the company medical department would decide in the near future whether the individual had a medical disability that required written NRC notification. The individual had returned to work but had not been cleared for licensed duties at the time of the exit meeting. The Station Manager stated that a memorandum would be issued to licensed personnel (not performing licensed activities) reminding them of the reporting requirement. This item will remain open pending the result of the medical evaluation (86-01-04).

In a related matter, on January 23, 1986, a reactor operator (RO) was relieved from a routine watch because of a medical complaint and sent to a local hospital. A replacement RO was onsite within 40 minutes of

the incident. The complaint was transitory and the licensee indicated that it did not require reporting to the NRC under 10 CFR 55.41. The inspector subsequently interviewed the RO and had no further questions.

g. Reactor Scram on Spurious High Pressure Signals

On January 16, 1986, a half scram signal was unexpectedly received during a routine reactor water level instrumentation surveillance test. The half scram was generated by a spurious reactor high pressure signal from a Barton pressure switch, no. PS-263-55C. The licensee halted the water level surveillance test and investigated the signal.

The licensee investigation indicated that gentle taps on pressure switch PS-263-55C would generate a high pressure signal and produce a half scram trip. While the switch was being replaced later that night, a switch mounted on an adjacent rack, PS-263-55D, also generated a spurious high pressure signal which produced a second half scram and caused a full reactor scram. The technicians who were replacing the 55C switch indicated that they did not jar the 55D switch.

The reactor was at 100% power at the time of the scram. Routine scram recovery procedures were used to stabilize the plant. A reactor startup was initiated at 7:27 a.m. on January 18, 1986. Full power was achieved on January 2^, 1986.

Prior to the startup, the licensee evaluated the reactor high pressure switches and found that they all were more sensitive to external vibration while pressurized than previously thought.

As corrective action, the setpoints for the switches were raised from 1080 to 1087 psig. These switches indicated 12 psig higher than reactor dome pressure due to instrument water legs. The inspector reviewed the licensee calculation of the water leg correction, dated June 7, 1972, and identified no problems. The actual reactor pressure at which the switches would trip is 1075 psig (i.e., 1087 minus 12 psig). This is still below the technical specification limit of 1085 psig. The electrohydraulic pressure regulator (EPR) was adjusted so that steam pressure at 100% power was reduced to 1027 psig, increasing the pressure range between normal operation and the high pressure trip. Also, pressure sensing lines were wrapped with foam insulation (temporary modification 86-02) to reduce vibration.

The inspector discussed the pressure switch problem with maintenance personnel and had no further questions at this time. A previous high pressure scram occurred during a surveillance test on March 15, 1985 (LER 85-006).

h. Turbine Vibration Transient

On January 29, 1986 at 5:15 a.m., vibration rapidly increased on the No. 9 main turbine generator bearing to approximately 13 mils. The vibration quickly subsided and was down to 2 mils, twenty minutes later. Reactor

power was reduced 10% while the problem was evaluated. The licensee believes that the transient was caused by the accumulation of an unstable oil film on the bearing, termed oil whip.

Subsequently, the licensee changed the temperatures of the generator exciter (to increase load on the bearing) and the turbine generator lubricating oil. The phenomena has not recurred. The inspector had no further questions.

i. <u>Isolated Phase Bus Cooling Motor Trip</u>

On February 3, 1986, the backup fan motor tripped for the main electrical isolated phase bus duct cooler. The electrical conductors in these ducts transmit power from the main generator to the station transformers. Reactor power was reduced to 90% until proper bus cooling was reestablished later that day.

Two redundant fan motors are installed in the bus cooling unit. The primary motor had been removed from service the previous week because of excessive motor heat and bearing noise. Subsequently both motors were found to have worn bearings and the motors were replaced.

The licensee indicated that the motors were original plant equipment and had not previously had problems. The licensee plans to perform preventative maintenance on the motors in the future. The inspector had no further questions.

j. <u>Recirculation Flow Transient</u>

On February 6, 1986 at approximately 5:30 a.m. with the reactor at 100% power, flow unexpectantly increased in the "B" recirculation loop, causing a slight reactor pressure transient. Core flow increased by about 2 E6 lb/hr during the transient. Reactor pressure increased from 1033 to 1042 psig and the turbine control valves opened to control pressure. Turbine bypass valves did not open during the transient. The transient lasted for approximately five minutes. A second, shorter transient occurred the next day.

The licensee believes that the transients may be caused by flow instabilities in the recirculation loops, termed bistable vortex. General Electric prepared a safety evaluation for Boston Edison in 1985 describing the phenomena in the "A" loop and indicating that it caused no safety problems. A second evaluation was prepared for the "B" loop. The licensee has accepted the "A" loop evaluation and is reviewing the "B" loop report.

The licensee subsequently connected a brush recorder to the recirculation speed control circuit of the "B" loop to confirm that flow increases are not caused by control problems. A recorder had previously been connected to the "A" recirculation loop. The recorders are located behind a con-

trol panel in the control room. The inspector expressed concern about the fire hazard posed by excess recorder paper that was allowed to run into the back of control room panels. The licensee subsequently assigned the Shift Technical Advisors the responsibility to monitor the chart paper. No subsequent problems were observed.

Recirculation loop flow instabilities have been discussed in NRC Inspection Reports 50-293/85-03 and 85-20. The results of the licensee evaluation will be followed under a previous open item, 85-03-02.

k. Loss of Safety Bus B-20

On February 11, 1986 at 10:39 a.m. with the reactor at full power, feeder breaker B604 tripped open on overload during a cable repair, isolating a 480 V a.c. safety bus (B20). Safety equipment powered by the bus included LPCI injection valves and reactor water cleanup primary containment isolation valves. Bus power was restored eight minutes later.

The inspector observed operator actions in the control room to recover B-20 and noted that they acted promptly and effectively to recover the bus. However, the operators used an out of date drawing (SE-E-115, dated April 18, 1984) of the plant electrical system during the incident. The current drawing revision, dated December 17, 1985 showed a slightly different B-20 wiring lineup than the older drawing. However, the differences did not appear to affect operator response. At the exit meeting, the licensee indicated that an up to date, controlled copy of the drawing would be placed in the control room. The inspector had no further questions regarding operator actions.

The bus faulted to ground during a cable repair, maintenance request 84-46-512. The cable powered a 480V welding receptacle and was thought to be deenergized at the time of the repair. The licensee later found that a jumper had been installed which transferred receptacle feed from a 70-amp breaker designated on plant drawings (B2013B) to a spare 100-amp breaker (B2016B). Only the 70-amp breaker was tagged open prior to the repairs, which left the cable live. The worker performing the cable repair was not injured.

The jumper was apparently installed in 1976 and may have invalidated the environmental qualification of the bus. The welding circuit had been tagged open (B2013B) because of concern that non-environmentally qualified portions of the circuit might fault in a harsh environment and disable B20. The licensee stated that the jumper had been installed to B2016B under a 1976 maintenance request, in order to provide increased electrical power for a hydrolazer.

On February 11, 1986, the licensee walked down the spare breakers on other 480 V safety panels and verified that no other jumpers were installed. A safety meeting was subsequently held with all electricians to discuss the incident and stress the need to test electrical components prior to maintenance to ensure that they are deenergized.

The inspector reviewed maintenance documentation for the cable repair and observed electricians disconnecting the welding circuit from B20. The inspector could find no evidence that the 70-amp breaker (B2013B) had been tagged open at the time the 1984 maintenance request to repair cable damage was issued. The breaker was subsequently tagged open with Watch Engineer Tag 46-147 on November 30, 1985, for environmental qualification reasons.

The acceptability of licensee actions regarding the placement of the original jumpers, the tagging of the 70-amp breaker in 1984, and the environmental qualification of bus B20 are unresolved, pending further NRC and licensee evaluation (86-01-05).

1. Core Spray Valve Inoperable and RHR Pressurization Events

On February 13, 1986 at 9:30 a.m. with the plant at 100% power, the "B" loop of the core spray system was declared inoperable when a motor operated injection valve failed to close in the required time during a surveillance test. The valve, MO-1400-25B, closed in 18.1 seconds (versus a required time limit of 18.0 seconds). The loop was subsequently returned to service at 7:15 p.m. that evening, after a safety evaluation indicated that the acceptance limit could be increased to 20 seconds. Closing times have been near the 18 second limit (e.g., 17.9 seconds closing time) since the valve was modified for environmental qualification purposes in July 1985.

The inspector reviewed IST data for the core spray valve, MO-1400-25B, and concluded that valve times had been uniform since environmental qualification modifications were completed last summer.

The core spray surveillance was conducted in preparation to declaring a LPCI injection valve, MO-1001-28A, inoperable for inspection and repair. Periodic residual heat removal (RHR) high system pressure alarms (≈400 psig) had been occurring for several weeks and RHR system piping between the 28B valve and the RHR pumps had been noted to be warm. The licensee subsequently determined that the RHR system was being pressurized due to back leakage of primary coolant through an inboard check valve and the 1001-28B injection valve. A second in line injection valve is normally maintained open. The design pressure for that section of the RHR system is 500 psig. The high pressure alarms were noted, but not logged. Operators vented the piping after each alarm. The alarm frequency varied, but sometimes occurred as often as twice a shift. There were no other indications of piping pressure for that section of the RHR system other than a high pressure annunciator.

The inspector expressed concern about the primary containment implications of the leaking RHR injection and check valves. The licensee indicated that the normally open 1001-29B injection valve was the primary containment isolation valve in the "B" RHR loop. The FSAR indicates that this valve receives a group 3 automatic isolation signal when the RHR

system is in the shutdown cooling mode. The RHR check valve, 1001-68B is not leak rate tested. The normally closed 1001-29B injection valve does not get an automatic containment isolation signal. However, the FSAR indicates that it receives a remote manual primary containment isolation signal from the control room.

The licensee subsequently found that the 28B valve closing torque switch activated early, at about 75 amps of closing current. The switch had previously been set to activate at an operator torque switch which corresponded to a closing current of more than 100 amps. The licensee adjusted the torque switch and examined the operator spring pack. No other problems were identified. The valve was declared operable at on February 15, 1986. On February 17, 1986 at 8:40 a.m., the RHR high pressure alarm was again received, indicating that the 28B valve was still slightly leaking.

The licensee subsequently attempted to verify the integrity of the RHR check valves in each RHR loop by depressurizing the piping between the loop injection valves, closing both valves, and then opening the injection valve adjacent to the loop check valve. However, the RHR pipe quickly repressurized in each loop during the tests.

At the exit meeting, the licensee indicated that the status of RHR check valves had been discussed in correspondence with the NRC. A licensee engineer is gathering the documentation together.

The acceptability of the new core spray valve closure time is unresolved pending a review of the licensee safety evaluation. The acceptability of licensee actions in response to the RHR pressurization events is also unresolved pending a review of the primary containment implications of the leaking RHR valves (86-01-06).

m. Diesel Fuel Oil Viscosity

On February 14, 1986 with the reactor at 100% power, a contractor laboratory notified the licensee that the February fuel oil sample from the "A" diesel fuel oil storage had a viscosity of 32.4 SSU, which did not meet the limits of ASTM D975-1977. The Technical Specifications require that the fuel oil quality meet or exceed the limits of ASTM D975-1977. The ASTM standard requires that the fuel oil viscosity be between 32.6 and 40.1 SSU.

The licensee declared the "A" diesel generator inoperable at 10:32 a.m. Surveillance testing on the ECCS systems and the remaining diesel generator was already planned, because ongoing maintenance to the LPCI 28B valve (see previous section). The licensee also declared an unusual event because the technical specifications require that a reactor shutdown be initiated with both the LPCI system and the "A" diesel generator inoperable.

The contractor laboratory retested the sample and found a viscosity of 33.6 SSU, which was within the ASTM limit. A second sample from the "A" tank was also sent to the contractor laboratory for analysis. The licensee conducted two viscosity tests on a recent sample from the "A" storage tank and found viscosities of 33.9 and 33.2 SSU. The licensee indicated that the last fuel oil addition to the storage tank occurred in November, 1985. Monthly test results for December, 1985 and January, 1986 were 32.6 and 33.1 SSU, respectively. The licensee declared the "A" diesel generator operable and terminated the unusual event at 12:32 pm. on February 14, 1986, based on the supplementary fuel oil tests. The inspector had no further questions at this time.

6. Observations of Physical Security

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, personnel identification, access control, badging, and compensatory measures when required.

-- On February 15, 1986 at 2:17 a.m., a contractor security supervisor noted that a guard posted at an opening to a vital area was sitting in a chair, apparently asleep. The supervisor approached the guard, called the guard's name, but the guard did not respond. The supervisor remained near the opening and sent a second guard to check the vital area. The first guard was relieved from duty.

At 6:17 a.m., the licensee notified the NRC of the incident via the ENS telephone line. The inspector subsequently reenacted the incident with the supervisor at the vital area opening. The supervisor indicated that the guard had been observed awake at his post earlier in the evening. This item will be reviewed further during a future routine security inspection (86-01-07).

7. Radiation Protection

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of nonradiological points throughout the facility were taken by the inspector. The following problem was noted.

-- On January 30, 1986, the inspector noted that one frisker in the reactor building did not have an attached probe and a second frisker in the building had been removed. Health physics technicians indicated that there was a shortage of friskers (RM-14) and probes because of problems with the instrument calibration procedures. They stated that the procedures had been written by contractors but not field tested prior to implementation.

The inspector discussed the status of health physics equipment calibration with the Radiation Protection Section Manager. He confirmed that problems had been encountered with the implementation of recent instrument calibration procedures. He indicated that the new procedures were of higher quality than the old procedures and that implementation was more difficult than originally anticipated. He indicated that a technician review committee had been previously established to review new procedures prior to issuance. The frisker calibration procedure preceeded the committee.

The licensee subsequently revised the frisker and frisker probe calibration procedure to return to the previous calibration method. The licensee indicated that new calibration procedures for other radiation survey equipment were acceptable and had not generated instrument shortages. Failure to properly field test calibration procedures prior to procedure implementation is a licensee identified weakness. The inspector had no further questions at this time.

8. Control Room Indicating Lights and Annunciators

Two incidents occurred during the inspection period that indicate a lack of aggressiveness in repairing nonsafety equipment and reducing unnecessary annunciators on the part of the control room staff.

a. Indicating Lights

On January 6, 1986 just prior to a reactor startup, the inspector toured the control room and noted that the following control room indicator lights should have been lit, but were out:

Number of Lights	Function and Location
3	APRM scram trip set down at the local panel
>20	LPRM downscale lights at the local panel
>25	Control rod full-in lights on the full core display

The inspector expressed concern with the lack of operator attention to the lights to the Chief Operating Engineer. The lights were subsequently checked. Many were burned out. Others had bulb socket problems. The average power range monitor (APRM) set down lights were burned out. The licensee stated that APRM set down trip function had been recently verified.

Previous NRC concerns about licensee inattention to burned out full core display lights are documented in NRC inspection report 50-293/84-39.

b. Activated and Disabled Annunciators

On Feb·uary 6, 1986, the inspector reviewed activated and disabled control room annunciators with control room personnel. A total of 18 activated and 16 disabled annunciators were noted. A detailed listing of the annunciators and the causes are shown in Attachment 2 to this report. The inspector discussed the need to minimize activated annunciators with control room personnel and licensee management. In response to the review, the licensee took steps to reduce the number of activated alarms. At the end of the inspection, the number of chronic activated annunciators had been reduced to 12.

During the followup, the inspector noted that the following annunciators had been disabled in the control room were properly tagged, but not logged:

Panel	Date Disabled	Annunciator
C1	1/2/85	Train A, fifth point heater high level
C2	7/8/85	Air Dryer End of Cycle
C7	2/26/85	Carbon dioxide storage tank high/low pressure

Procedure 2.3.1, "General Action (Alarm Procedures)", dated January 20, 1984 states that disabled annunciators shall be strictly controlled. The procedure also requires that a disabled annunciator be logged in the Disabled Annunciator Alarm Log. Failure to log the disabled annunciators described above is a violation of this procedure (86-01-08). A previous NRC violation for failure to tag and log control room annunciators was issued in 1981 (NRC report 50-293/81-02).

The licensee made two of the three annunciators operable at the time of the review by reinserting the annunciator cards in their sockets. The remaining annunciator (Air Dryer End of Cycle) serves no current function and was left disabled. Carbon dioxide storage tank pressure, one of the disabled annunciators, is logged daily.

9. Emergency Re-entry Procedure

The inspector reviewed a recent revision of the licensee's emergency building re-entry procedure in preparation for a forthcoming re-entry drill. The procedure required that radiological conditions and physical conditions be evaluated and that the re-entry team have a clear understanding of the tasks to be accomplished. However, the procedure waived these requirements if "the urgency of the re-entry is so great as to preclude" their performance. The inspector questioned this exemption, since it could be interpreted to allow anyone access to a process building in an emergency without an adequate evaluation of the building conditions.

The licensee indicated that the intent was to waive the paperwork (but not the evaluation) in a life-threatening or plant threatening situation. The licensee further indicated that the procedure would be revised to better reflect this intent.

The adequacy of the licensee's revised re-entry procedure will be evaluated during followup to the upcoming re-entry exercise. The inspector had no further questions.

10. Post Trip Reviews

The inspector reviewed the post trip reviews that had been completed for the reactor scrams on January 6 and 16, 1986. Procedure 1.3.37, "Post Trip Reviews", requires that data be collected and assembled in a Post Trip Review (PTR) package in order to reconstruct the reactor trip, assess the response of systems, and identify the root cause of the event. Copies of recorder charts for certain control room parameters, including APRM power, reactor feedwater flow, reactor pressure, and reactor level are required to be attached to each trip report. The procedure also requires that the recorder chart speed be indicated on the recorder charts. The following deficiencies in the post trip reviews were noted:

-- The January 6, 1986 trip report, PTR 86-01, did not have copies of the control room charts attached to the report. The trip report indicated that the startup of the unit precluded removing the recorder charts. A Shift Technical Advisor (STA) who came on duty shortly after the trip indicated that the charts may not have been immediately removed due to a shortage of chart paper in the control room. At the exit meeting, the inspector noted that a subsequent LER describing this scram contained more details of the event than PTR 86-01. The PTR indicated that the scram was caused by a lack of appropriate operator action, but the PTR did not describe what actions should have been taken. The subsequent PTR, 86-02, contained a fuller description of that event.

-- The January 16, 1986 trip report, PTR 86-02, included the required copies of the recorder charts. However, no recorder chart speeds were indicated in the PTR package.

Redundant information during the trip was shown on computer printouts of plant parameters attached to both trip reports. However, the printouts only cover a five minute period. The recorder charts can show trends over longer periods of time. Trip reports 86-01 and 86-02 were reviewed and accepted by the Operations Review Committee (ORC) on January 8 and 17, 1986, respectively. Failure to follow procedure 1.3.37 during the preparation of these reports is a violation of Technical Specification 6.8 (86-01-09).

11. Review of Licensee Event Reports (LER's)

LER's submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information

was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LER's were reviewed.

LER No.	Event Date	Report Date	Subject
81-022/03X-1 (Update)	5/19/81	1/8/86	Leak Detection Air Sampler
86-001-00	1/06/86	2/4/86	Reactor Scram on Low Water Level Due to Operator Error

The inspector reviewed LER 81-022 (update) and had no questions. The scram described in LER 86-001 is discussed in section 5 of this report. The inspector noted that this LER did not contain all the details that are required to be reported by 10 CFR 50.73 (b)(2)(ii)(J). Specifically, the LER did not discuss the cause of the operator error that led to the scram. The LER also did not indicate how the error related to procedural instructions. The licensee stated that the LER would be updated to reflect this information. The inspector had no further questions concerning the LER's.

12. Review of TMI Action Plan Items

II.K.3.28 - Qualification of Automatic Depressurization System (ADS) Accumulators. The inspector reviewed the safety evaluation report (SER) on this item, issued December 23, 1985. The SER accepted the ability of the ADS accumulators to perform their function during a design basis event provided that the accumulators are leak tested during each outage to demonstrate their pressure retaining capability. The inspector reviewed completed Procedure 8.7.1.10, Pressure Test ADS Accumulators' System Integrity, Revision 4, used to perform the leak testing in December 1984. Based on the acceptable testing, this item is closed.

II.K.3.13 - Reactor Core Isolation Cooling (RCIC) System Automatic Restart. The inspector reviewed the SER issued March 16, 1983 which accepted the modification of the RCIC system logic such that on a high reactor vessel level signal, the steam supply valve will close and the RCIC turbine trip valve will not. Thereafter, on a subsequent low level signal, the supply valve will reopen, and the RCIC system will automatically restart. The inspector reviewed the operating procedure for RCIC, Procedure 2.2.22, which described the revised method of operation in Section II.D, Turbine Control, and Procedure 8.M.2-2.10.11, RCIC Trip Functional Test, which tests the closing of the steam supply valve. Also, the inspector reviewed the functional control diagram and electrical diagrams for RCIC to confirm that the modified circuits were correct and reviewed the records for the functional tests completed on December 18, 1984 and June 20, 1985. This item is closed.

II.K.3.16 - Reduction of Safety Relief Valve (SRV) Challenges and Failures. The inspector reviewed the SER for this item issued April 3, 1984, and the licensee response in letter BECo 84-89 dated June 20, 1984, and the final NRR letter dated November 17, 1984, which agreed with the licensee response. The licensee committed to revise Emergency Operating Procedure (EOP-1) to manually initiate a reactor pressure reduction to 930 psig when pressure reduction was necessary, to increase the SRV simmer margin, and to implement a preventive maintenance program for the SRVs. The inspector confirmed that EOP-1 contained the proper instructions. The simmer margin (SRV setpoint - operating pressure) had been 55 psi during the previous cycle, but was 85 psi (1115-1030) when checked by the inspector. The licensee committed to maintain a minimum margin of 65 psi. The inspector reviewed the preventive maintenance program for the SRVs, including Procedure 3.M.4-6 for testing disassembly, and inspection of the SRVs and the Safety Valve Set Pressure and Leakage Test Report on all six valves dated October 26, 1984. The inspector found the program to be acceptable. This item is closed.

13. Management Meetings

During the inspection, licensee management was periodically notified of the preliminary findings by the resident inspectors. A summary was also provided at the conclusion of the inspection and prior to report issuance. No written material was provided to the licensee during this inspection.

ATTACHMENT 1 TO INSPECTION REPORT 50-293/86-01

1. Portions of the following surveillance tests were reviewed:

   -- MSIV quarterly closing time tests, procedure 8.7.4.4 conducted on January 4, 1986; June 23, 1985; March 19, 1985; February 15, 1985; and February 1, 1985

   -- "B" RBCCW pressure indicator calibration, procedure 8.E.30, conducted on January 13, 1986 was observed

   -- The basis for the Yarway reference chamber water leg correction, dated June 7, 1972

   -- The main steam line high radiation monitor calibration, Procedure 8.M.1-13.1, conducted on January 30, 1986 was observed

   -- The IST tests for salt service water pump discharge pressure, Procedure 8.5.3.2, conducted in 1985 and 1986.

2. Portions of the following maintenance and modification activities were reviewed:

   -- MR 83-33-91, Install conduit, cable and smoke detectors

   -- MR 86-12, Check valve leaking on 33B valve test connection

   -- MR 86-29 and MR-86-217, Pipe hanger is not in contact with pipe

   -- MR 86-18 and 86-194, Vent connection between 1001-33A and 1001-68A shows a linear indication

   -- MR 84-46-512, Cable shorted out

   -- MR 86-53 and MR 86-54, No light indication on MO 1001-29A valve and replacement of control circuit fuses with metal links

   -- MR 86-7, Relay 16AK65 coil burned out

   -- MR 86-58, Half scram

   -- MR 86-71, Change setpoint of reactor building high pressure switches

   -- MR 86-8, MSIV closed in excess of five seconds

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ATTACHMENT 2 TO INSPECTION REPORT 50-293/86-01

Panel	Annunciator	Activated (A) or Disabled (D)	Stated Cause
C903	RHR SD Cooling High Rx Pres, Channel A	A	Activates at >100 psig reactor pressure
	RHR SD Cooling High Rx Pres, Channel B	A	Activates at >10C psig reactor pressure
	HPCI Turbine Oil Cooler Disch. HiOil Temp	D	Broken temperature switch
C904	Cleanup Reject Hi/Lo Press.	A	Leaking rx cleanup system valve
C905	Rod Withdraw Block	D	Nuisance alarm; annunciator is activated during power changes
	C7 Kaye High Temp CRD/Ref. Leg Plant Air	D	Nuisance alarm; CRD temperatures sometimes high
	Scram Discharge Volume East Headers - Trouble	D	Not in use
	Scram Discharge Volume West Headers - Trouble	D	Not in use
	APRM Hi	D	Nuisance alarm
	IRM Downscale	A	IRM's withdrawn from reactor core
C2	Lube Oil Purifier - Trouble	A	Alarms when lube oil purifier not in use
	*Air Dryer End of Cycle	D	Design change, not in use
	H2 Analyzer A Low Flow	D	Not in use
	H2 Analyzer B Low Flow	D	Not in use

Panel	Annunciator	Activated (A) or DisableJ (D)	Stated Cause
C2	Air Dryer High Moisture	A	Bad detector
	Fire Pump Trouble	A	Diesel fire pump out for maintenance
	Mech. Vacuum Pump Seal Water Low Flow	A	Alarms when mech. vacuum pump not in use
C1	*Train A, 5th PT Heater High Level	D	Nuisance alarm
	Train B, 5th PT Heater High Level	A	Problems with heater level control instrum.
	Train A, 4th PT Heater Low Level	A	Problems with heater level control instrum.
	Train B, 4th PT Heater Low Level	A	Problems with heater level control instrum.
CP600 (offgas)	Absorber Train Inlet/ Outlet Pres	A	Annunciator circuit malfunction; press ok
CP600 (offgas)	Condenser "A" Drainwell LVL Hi/Lo - A	D	Not in use
	Condenser "A" Drainwell LVL Hi/Lo - C	D	Not in use
	Condenser "B" Drainwell LVL Hi/Lo - B	A	Not in use
	Condenser 'A' Gas Outlet Temp. Hi	A	Train 'A' not in service, cond. cooling isolated
CP600	Lo RGE Hi/Lo Inlet Flow to Holdup Line	A	No flow indication instrument in control room, shift believes offgas flow is low (after recombining)
	Hi RGE Hi/Lo Inlet Flow to Holdup Line	A	
C170	PASS Containment Switches Open Position	A	Normally closed isolation valves have been opened for O2 analyzers, valves will automatically close

Panel	Annunciator	Activated (A) or Disabled (D)	Stated Cause
C7	Control Room Environmental Air Fan Trip	D	Problem unknown, annunciator card reinstalled
	*CO2 Storage Tank Hi/Lo Pressure	D	Problem unknown, annunciator card reinstalled
C6	High Temperature B18 Fan/Damper Auto Start	A	Problem unknown, licensee investigating

*Disabled annunciator not logged.