U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 87-01/87-02

Docket No. 50-220/50-410

License No. DPR-63/NPF-54 Category B

Licensee: Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility: Nine Mile Point, Units 1 and 2

Location: Scriba, New York

Dates: January 4, 1987 to March 1, 1987

Inspectors: W.A. Cook, Senior Resident Inspector
C.S. Marschall, Resident Inspector
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Reviewed by: G. Meyer, Project Engineer, Reactor Projects Section 2C, DRP — 3-30-87 Date

Approved by: J.C. Linville, Chief, Reactor Projects Section 2C, DRP — 3/30/87 Date

INSPECTION SUMMARY

Areas Inspected: Routine inspection by the resident inspectors of station activities (including Unit 1 power operations and Unit 2 preparations for initial criticality), licensee action on previously identified items, surveillance testing, safety system walkdowns, LER review, allegation followup, review of licensee responses to IE Bulletins and Notices, and emergency diesel generator problem reviews. This inspection involved 576 hours by the inspectors. One violation was identified.

Results: Unit 1 APRM scram and rod block clamping functions are discussed in section 2. Unit 2 MSIV progress is discussed in sections 2.a. and 2.d. A violation of 10CFR21 reporting requirements is discussed in section 3.a. An unresolved item concerning LER 87-14 is discussed in section 6.d. A Unit 1 allegation concerning off site access to station computers is discussed in section 7.

DETAILS

1. Review of Plant Events

UNIT 1

The plant operated at full power throughout the report period.

On January 9, 1987, the licensee notified the NRC that the Average Power Range Monitor (APRM) flow biased scram and rod block functions had no fixed upper limit (i.e., were not "clamped") at 100 percent flow as specified in Technical Specification Figure 2.2.1. Although the licensee first became aware of the potential APRM instrumentation deficiency on January 6, 1987, after a similar problem was identified at Oyster Creek, an evaluation of the Unit 1 APRMs was not completed until January 9, 1987. The licensee conducted testing of the APRMs and determined that circuitry did exist to clamp the scram trip setting at 120% power (at 100% recirculation flow), however, the circuitry had never been calibrated to perform that function. The licensee also discovered that there was no circuitry to clamp the rod block function of the APRMs, as required by Technical Specification. The licensee immediately calibrated the APRM scram clamp circuitry and, through consultation with GE, designed and installed a temporary modification to clamp the rod block function of the APRMs. The licensee has submitted a Technical Specification amendment to remove the requirement for the APRM clamp functions. The amendment was based on an analysis which prohibits unit operation at greater than 100% recirculation flow. Unit operation above 100% recirculation flow is currently prevented by electrical clamping circuits and mechanical restrictions on the recirculation flow control system. The licensee proposes to include in the Technical Specification change request a surveillance requirement for a once per cycle calibration of the recirculation flow control system electrical and mechanical clamps.

On February 12, 1987, the licensee discovered that the diaphragm in the scram inlet valve for Control Rod Drive 14-19 was leaking air. Neither the scram inlet valve nor the scram outlet valve had opened as a result of this diaphragm failure. The control rod was inserted without incident, and the diaphragm, which had ruptured through the diameter, was replaced. The licensee was unable to determine why the scram inlet valve failed to open, in view of a similar incident on September 8, 1986, (see combined Inspection Report 50-220/86-18 and 50-410/86-42). The licensee is awaiting the results of an analysis by General Electric, started in late February 1987, to ascertain any safety significance of these events.

UNIT 2

a. Main Steam Isolation Valve Review

During the reporting period, licensee progress in resolving MSIV problems was closely monitored. Significant events reviewed by the inspectors are discussed below:

(1) While setting MSIV limit switches, during the week of February 8, valve 6B did not operate properly. Upon inspection of the valve circuitry, a burned out relay was found. Licensee troubleshooting could not identify or reproduce the fault. Further examination of the MSIV control panels identified several cracked casings on ITE Gould J10 and J20 type relays. Inside the MSIV relay panels, the relays are separated from their respective base by a metal fire barrier and held together by two screws. The licensee determined that cracking was due to the misalignment of the relay bracket with the metal fire barrier and the subsequent over-torquing of the screws when the relays were joined with their bases. The licensee could not determine whether the relays were cracked during initial installation or during subsequent MSIV relay panel modification.

The inspectors reviewed E&DCRs No. C54084 and M10074C generated to correct the relay bracket installation deficiencies and relay replacements. The inspectors also observed relay replacement activities, performed on February 13, in accordance with N2-EMP-118.2, Repair of Category 1 and 1E Electrical Equipment, revision 0, March 1986. No deficiencies were observed.

(2) On February 8, the licensee discovered that the packing was leaking on the prototype valve being tested at the vendor's facility. The leakage path developed as the valve was cooled from normal operating temperature to ambient. The licensee determined that as the seat spool and valve body contracted during cool down, the valve packing which seals the area between the spool and the valve body remained compressed, and did not seal. At the conclusion of this inspection period, the licensee was experimenting with several new types of packing designs to attempt to correct the problem. Initial criticality is still contingent upon final resolution of the MSIV leakage problem.

(3) On February 17, during containment isolation testing, two of eight MSIVs failed to shut (6A and 6B), five valves (6C, 6D, 7B, 7C, and 7D) shut but not within the required 3-5 second interval, and one valve (7A) shut in the required time. The isolation procedure was written such that only one of the two MSIV soleniod valves would open to bleed off the hydraulic fluid and allow the MSIV to close. The licensee determined that the five MSIVs that closed in greater than the required time did so because both solenoids need to function to allow the proper bleed rate of the hydraulic fluid. The one MSIV that closed within the required time did so because a jumper that was to keep one of the solenoids energized (closed) fell off, and both solenoid valves operated to bleed off fluid. Circuit checks were conducted to evaluate the reason for the failure of two MSIVs to close. No wiring problems were identified. The licensee then disconnected the hydraulic actuators from the valves to allow the actuators to be pressurized and cycled

without valve motion. During the actuator cycling, each solenoid was timed, and it was determined that the A solenoid on each actuator was not operating. These two solenoids were disassembled and found to be missing the spacer ring that was to have been installed to increase the spring force available to open the valve when the solenoid deenergized. Licensee review of documentation showed that the installation of these spacer rings could not be confirmed in any of the inside containment MSIVs. The licensee disassembled all the solenoids on the suspect MSIVs and found that six of the eight were missing the spacers. The valves were reassembled with the spacers and retested satisfactorily.

b. During this inspection period, several inadvertent actuations of the Standby Gas Treatment (SBGT) System occurred.

(1) On January 9, both SBGT System trains automatically initiated during maintenance on the reactor building normal ventilation system. The Station Shift Supervisor (SSS) mistakenly authorized a tagout to be hung which caused dampers to reposition and a low flow condition to develop in the normal ventilation system. The low flow condition caused both trains of SBGT to automatically start and the normal ventilation system to isolate, by design. The licensee submitted LER 87-02 to document this event.

(2) On January 16, while performing a channel check on the reactor building ventilation system below the refuel floor process radiation monitor, a jumper fell off a terminal and shorted to ground. This caused a damper to close and a low flow condition in the normal ventilation system. By design, initiation signals were sent to both trains of SBGT and both reactor building recirculation units, and an isolation signal was sent to the reactor building normal ventilation system. The ventilation system isolated, but only one of the two recirculation units started. Both trains of SBGT and the one recirculation unit did not start because they were in pull-to-lock. This event was similar to an event which occurred on November 25, 1986, when a jumper fell off during the performance of the same surveillance test and caused a similar sequence of events. The licensee has implemented a solution to the jumper problem for this surveillance test. A crimp-type connector has been added to the applicable terminals, and the crimp end is bent so that it is parallel to the terminal stake. The crimp end is sized such that a banana-type connector on the jumper will slide into the end and provide a tight connection. This solution was reviewed by the inspector and found to be satisfactory. No similar jumper problems have been identified by the licensee while performing other surveillance tests. This event was documented by the licensee in LER 87-03.

(3) On February 2, the two running reactor building ventilation supply fans tripped when an electrician bumped a relay in the ventilation control panel. When both fans tripped, the supply fan in standby started, as designed. However, the resulting ventilation system fan configuration of two exhaust fans and one supply fan caused the secondary containment differential pressure to drop to the minus three inches of water exhaust fan trip setpoint and both exhaust fans tripped. This resulted in a reactor building ventilation low flow condition and both trains of SBGT initiated. A similar event occurred on November 28, 1986, but the cause of the low flow condition could not be determined. The licensee has performed testing which they say demonstrated that the cause of both events can be attributed to tripping the exhaust fans on the reduction of the secondary containment pressure.

(4) On February 24, due to an inadvertant interruption of power to their logic circuits, the primary containment isolated and the SBGT System automatically started. The logic circuit power interruption occurred when an operator opened the wrong breaker during reactor protection system troubleshooting. The inspector determined that the operator was told to open the correct breaker, but was confused and mistakenly opened a different breaker.

All of the automatic SBGT System actuations were reported to the Headquarters Duty Officer via the ENS.

c. During this inspection report period, the licensee issued two 10CFR21 reports.

(1) The licensee has determined that the failure of an Agastat relay on December 15, 1986, was due to improper seating of the relay unit in its base. These type of relays are used in safety and nonsafety related applications at Unit 1 and Unit 2. The licensee determined that an insufficient amount of force was used to seat the relays. GE recommended that 50 pounds of force be used and that the proper seating then be verified using a feeler gage. This event was documented in LER 86-27.

(2) A duct bank manhole was improperly sealed. An evaluation was performed and it was determined that if a condenser expansion joint failed, this manhole could be covered with water and most probably fail. The water could then flood the duct bank which communicates with the control building and service water bays. Flooding of the service water bays could potentially cause the loss of safety-related service water pumps. The licensee plans to redesign the manhole seal and have it installed prior to initial criticality. This event was documented in LER 86-26.

d. Three automatic MSIV closures occurred which were all related to surveillance activities.

(1) On January 26, main turbine stop valve limit switches were being tested in conjunction with preparations for the reactor pressure vessel operational leak test. After one stop valve had been cycled and its limit switches adjusted, its associated stop valve open/low condenser vacuum MSIV isolation signal was not reset. When a second stop valve was cycled, the two open stop valve/low condenser vacuum isolation signals satisfied the MSIV automatic closure logic, and all MSIVs received a closure signal. Only the inside containment MSIVs were open at the time and they stroked shut. This event was documented by the licensee in LER 87-09.

(2) On February 2, while performing excess flow check valve testing, several signals were generated for low reactor vessel level trip. These signals are anticipated, but not always received. In this instance, one level detector sensed a false low level condition creating a half isolation signal for the MSIVs. This half isolation was not indicated in the control room and was not reset when the signal cleared. During the testing of a subsequent check valve, another low level signal was generated which created the other half isolation signal which caused the MSIVs to automatically close. The licensee suspects that the first half isolation signal was not recognized in the control room due to concurrent circuit checks being performed on the MSIV actuator logic.

(3) On February 8, in preparation for cycling main turbine stop valves, the Electro-Hydraulic Control (EHC) System turbine trip was reset. Because the main generator output breaker was closed for station backfeed, when the turbine trip was reset, the EHC system automatically tried to establish 1800 RPM on the main turbine. The EHC system started to open the turbine stop valves and because the low condenser vacuum signal was locked in, the RPS logic was satisfied closing the MSIVs automatically. This event was documented in LER 87-12.

e. Two events occurred this inspection period involving bumped instrument sensing lines, which are similar to events which occurred on December 10 and 11, 1986.

(1) On February 2, a reactor scram and automatic start of the High Pressure Core Spray (HPCS) Diesel Generator occurred. The licensee traced the initiation signal to an operator opening a differential pressure detector isolation valve. This operation sent a pressure spike through a common sensing line to two detectors which caused the scram on low reactor vessel level. The pressure spike was also suspected to have traveled through these detectors to a common sensing line for detectors which

initiate the HPCS start logic. The HPCS pump did not start because the pump switch was in pull-to-lock.

(2) On February 7, a reactor scram (Level 3) and turbine and feed pump trips (Level 8) occurred. These events resulted from pressure spikes caused by the bumping a flexible section of the reactor vessel level instrumentation sensing line.

The licensee is presently evaluating solutions to these instrument sensitivity problems.

f. On February 9, the Chief Shift Operator (CSO) responded to a computer generated alarm on a breaker trip for a emergency switchboard, and inadvertantly caused a secondary containment isolation and automatic start of the control room ventilation special filter train. The computer indicated that the normal supply breaker was closed and the alternate switchboard supply breaker was open; however, the normal supply breaker position indicating light on the control panel was burned out. The CSO, cycled the normal supply breaker and momentarily deenergized the emergency switchboard without checking the light bulb first. All systems responded as designed.

Based on their reviews, the inspectors concluded that the NMPC evaluations of the events described above were accurate and corrective actions appeared appropriate.

2. Licensee Action on Previously Identified Items

a. (Open) INSPECTOR FOLLOWUP ITEM (50-220/86-12-01): Review of licensee action concerning the reporting requirements of 10CFR21 and 10CFR50.73. The inspector previously addressed the differences in reporting requirements of 10CFR21 and 10CFR50.73, as noted in Inspection Report 50-220/86-12. In subsequent discussions with licensee management, commitments were made on several occasions to address 10CFR21 and 10CFR50.73 reporting requirements separately.

On January 6, 1987, the licensee submitted Licensee Event Report (LER) 86-16. The report identified a Standby Gas Treatment System (SBGTS) flow switch design deficiency at Nine Mile Point Unit 2. The LER indicated that the filter train heaters were deenergizing on a low flow signal from the flow switch. The LER does not make any determination with regard to potential safety hazards. In addition, Block 11 of LER 86-16 indicated that the report was made pursuant to 10CFR50.73 (a)(2)(v). No other block was checked.

On January 23, 1987, a licensee Final Evaluation and Notification of Deviation, Defect or Failure To Comply was completed. The evaluation, Report No. F86-001, concluded in Part I that the loss of heating ability of the filters could reduce the capability of the SBGTS train to prevent or mitigate the consequences of an

accident such as a 10CFR100 release to the environment. This could have created a substantial safety hazard. Licensee procedure NEL-029, Notification Under 10CFR21, paragraph 6.4.1, requires that the Manager, Nuclear Technology or his designee:

-- Inform the Senior Vice President (Nuclear) or designated alternate of the condition within one working day of making the determination.

-- When required, orally inform the Director, Office of Inspection and Enforcement or the Administrator of the Region I Office of the condition that results in a substantial safety hazard within two working days of making the determination.

-- Determine if the written notification should be submitted as a 10CFR21 report or as part of a report submittal under other reporting requirements (e.g., LER, Response to Inquiry).

-- Document the notifications using Part II of attachment NEL-029.

Part II, Section 1, of Report No. F86-001, was completed with all signoffs pertaining to notification of the Vice President marked N/A or left blank. An asterisk in Section 1 referred to a footnote at the bottom of the page which stated, "All notification requirements of 10CFR21 have been met with the submittal of Licensee Event Report, LER 86-16, dated January 6, 1987". Part II, Section 2a., pertaining to NRC verbal notification, was marked N/A. Part II, Section 2b., pertaining to NRC written notification, referred to LER 86-16.

Discussions with the licensee revealed that the licensee considered that the commitment for notification of the Senior Vice President, Nuclear was satisfied because he was on distribution for Report No. F86-001. However, the licensee cannot document when that notification took place. In addition, notification of the Senior Vice President was not documented as required by procedure NEL-029.

Discussions with the licensee concerning Report No. F86-001 revealed that the licensee considered the requirement for notification in accordance with 10CFR21 was satisfied by LER 86-16. However, the LER made no mention of a substantial safety hazard determination. The determination that the design deficiency results in a potential substantial safety hazard was reached seventeen days after the LER was issued. In addition, NUREG 1022 states that "Other" should be used in LER Block 11, if a reporting requirement is met that is not specified in Block 11, and that the reporting requirement should be specifically described in the LER abstract and text. There was no reference in LER 86-16 of an intent to meet 10CFR21 reporting requirements. After further discussions between the licensee and resident inspectors, the licensee made verbal notification to Region I on February 28, 1987.

In summary, the licensee failed to document notification of the Senior Vice President, Nuclear of a 10CFR21 determination as required by procedure NEL-029. The licensee also failed to specify that their 10CFR21 notification was being covered by LER 86-16. LER 86-16 does not meet the reporting requirements of 10CFR21, in that:

-- It was issued seventeen days prior to the 10CFR21 determination.

-- It does not identify a potential substantial safety hazard.

-- It does not indicate that it fulfills 10CFR21 reporting requirements in Block 11, or elsewhere in the report.

In addition, the licensee failed to take appropriate action to preclude this reporting deficiency, as previously discussed between the resident inspectors and licensing personnel and documented in Inspection Report 50-220/86-12. The failure to meet the reporting requirements of 10CFR21 is a violation. VIOLATION (50-410/87-02-01)

b. (Closed) INSPECTOR FOLLOWUP ITEM (50-220/86-17-05): Review of lost tool in the reactor vessel. The inspector was present on the refuel floor to observe portions of the search for the lost tool. The licensee expended considerable time and effort, without success, to locate and retrieve the lost tool part. In addition, the inspector reviewed General Electric report MDE 720586, dated May 21, 1986, entitled, Lost Parts Analysis of Aluminum Tool Part for NMP Unit 1. The report concluded that the lost aluminum piece will most likely sink to the bottom of the annulus where it will oxidize and disintegrate in hot standby conditions. The report also concluded that there is no potential for flow blockage, interference with control rod motion, or detrimental chemical reactions. Based on the GE report, the licensee concluded that safe reactor operation was not compromised by the presence of the lost aluminum piece in the reactor.

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

3. Plant Inspection Tours

During this reporting period, the inspectors made frequent tours of the Unit 1 and 2 control rooms and accessible plant areas to monitor station activities and to make an independent assessment of equipment status, radiological conditions, safety and adherence to regulatory requirements. The following were observed:

Unit 1

The Unit 1 control room atmosphere continued to be typical of an average operational control room. The control room was normally quiet with no unnecessary personnel present. Routine business such as Radiation Work Permit and Work Request authorizations were conducted efficiently with a minimum of disruption to operators. Very little background noise was observed by the inspectors, and no extraneous reading material was present at any time. In general, control room habitability was good.

Plant housekeeping practices continued to vary. During one plant tour, for instance, most areas of the Reactor Building were relatively clean. However, the northeast corner room near the location of the Containment Spray pumps contained miscellaneous debris and several lengths of hose which had been used on some previous occasion without being returned to storage. Overall, housekeeping was adequate.

Unit 2

Unit 2 control room atmosphere continued to be closely monitored. During this inspection period, a portion of the station staff, including the Unit 2 Station Superintendent, Maintenance, Operations, Radiation Protection, Quality Assurance, Engineering and Construction Superintendents and their immediate subordinates, were involved in a four section, eight hour shift coverage program to support the final preparations for initial criticality. The inspectors observed that the Station Shift Supervisors were better informed of station activities and less burdened with administrative duties. However, activity level in the control room continued to be high in order to complete the necessary work items and surveillance testing for criticality.

Response to the violations identified in Inspection Report 50-410/86-56 included the implementation of a Lessons Learned Book. The purpose of this book was to be a means of communicating to the Operations staff the various lessons learned from previously identified problems or concerns. The inspectors have periodically reviewed the content and operator use of the Lessons Learned Book and determined that its implementation has not been clearly defined and consequently of limited value. The inspector discussed this observation with Operations management and determined that they were aware of the lack of attention given to the book and that action would be taken to improve its quality and usefulness. The inspectors will continue to monitor the program.

Plant readiness for initial criticality, with respect to housekeeping, continued to show improvement.

No violations were identified.

4. Surveillance Testing Review

The inspectors observed portions of the surveillance test procedures listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operation were met, and the system was correctly restored following the testing.

UNIT 2

-- N2-ISP-ISC-R001, Reactor Instrumentation Line Excess Flow Check Valve Operability Test, revision 1, January 1987, performed on February 4, 1987.

No violations were identified.

5. Safety System Operability Verification

On a sample basis, the inspectors directly examined selected safety system trains to verify that the systems were properly aligned in the standby mode. The following systems were examined:

Unit 1

- Core Spray System (both trains)
- Containment Spray System (both trains)
- Emergency Diesel Generators

Unit 2

- Residual Heat Removal System (all trains)
- Emergency Diesel Generators
- Automatic Depressurization System

No violations were observed.

6. Review of Licensee Event Reports (LERs)

The LERs submitted to the NRC were reviewed to determine whether the details were clearly reported, including accuracy of the description of the cause and adequacy of the corrective action. The inspectors also determined whether the assessment of potential safety consequences had been properly evaluated, whether generic implications were indicated, whether the event warranted on site follow-up, whether the reporting requirements of 10CFR50.72 were applicable, and whether the requirements of 10CFR50.73 had been properly met.

Unit 2

a. The following LERs were reviewed and found to be satisfactory: (Note: the date indicated is the event date)

-- LER 86-10 and LER 86-10, Rev.1, 11/23/86, Quarter core scram due to improperly operated electrical components.

-- LER 86-14, 12/3/86, Quarter core scram due to improper isolation.

-- LER 86-20, 12/18/86, Low Pressure Emergency Core Cooling System initiation.

-- LER 86-23, 12/23/86, Inoperable fire detector due to improper work controls. (Reviewed and documented in IR 50-410/86-65, section 2.c.1)

b. The following LERs were reviewed and found to be satisfactory, however, the identified corrective actions will be monitored and reviewed in a subsequent report:

-- LER 86-19, 12/15/86, Scram due to high scram discharge volume.

-- LER 86-24, 1/1/87, Divisions I and II emergency batteries inoperable due to corrosion on terminals.

-- LER 86-25, 12/31/86, Standby Gas Treatment System train B auto start due to wind effects.

c. The following LERS were reviewed and found to be satisfactory, (both describe Technical Specification violations):

-- LER 86-06, 11/12/86, Hourly fire watch surveillances missed.

-- LER 86-08 and LER 86-08, Rev. 1, 11/17/86, Inoperable fire barriers due to seals not being installed in imbedded conduit.

Both events were promptly reported to the NRC. Timely and proper corrective actions have been taken by the licensee. There have been no previous events of the same nature at Unit 2. The safety significance was minor in both instances. In accordance with the enforcement criteria of 10CFR2, Appendix C, Section V, a Notice of Violation was not issued for either of these licensee identified Technical Specification violations.

d. For the following LERs, the licensee has committed to issue supplemental reports. These reports will be reviewed in a subsequent report:

-- LER 86-07, 11/20/86, Half scram and containment isolations due to the tripping of both electrical protection assembled for an uninterrupted power supply.

-- LER 86-11, 11/27/86, SBGT initiation due to spiking process radiation monitor.

-- LER 86-12, 11/28/86, SBGT initiation due to tripping of a reactor building ventilation supply fan.

-- LER 87-14, 1/29/87, Radioactive Gaseous Effluent Monitoring Instrumentation Technical Specification Violation. On February 13, 1987, the licensee notified the NRC verbally of a violation of Technical Specification (TS) 3.3.7.11 Limiting Condition for Operation (LCO). Specifically, the LCO requires that four hour flow estimates be made when the Main Stack Effluent or Radwaste/ Reactor Building Vent Effluent flow monitors are inoperable. The licensee determined that the flow monitors were inoperable during a supervisory review of the monitor calibration data. The licensee's investigation of the root causes of this event was incomplete at the time this LER was submitted. The licensee intends to submit a supplemental report by May 31, 1987. The inspector will review the licensee's evaluation of this event in a subsequent reporting period. Enforcement action will be addressed at that time, if appropriate. UNRESOLVED ITEM 86-410/87-02-02.

7. Allegation Followup

During the inspection period, the inspectors conducted interviews and inspections in response to an allegation presented to the NRC. The inspector and licensee actions resulting from this allegations are noted below:

UNIT 1

Allegation RI-86-A-123: On October 6, 1986, the NRC received an allegation from an individual that the station computers could be accessed from offsite. In a letter dated November 14, 1986, the NRC requested that the licensee evaluate this allegation.

On January 26, 1987, licensee representatives met with the resident inspectors to discuss the licensee's evaluation of this allegation. The inspectors determined that limited access to some station computer systems is provided by telephone communications, however, access is appropriately controlled. The inspectors concluded that the allegation was unsubstantiated.

Licensee response to this allegation was documented in letter no. NMP1L-0132, dated February 9, 1987.

No violations were identified.

8. Licensee Action on IE Bulletins

The inspector reviewed licensee records related to the IE Bulletin identified below to verify that: the IE Bulletin was received and reviewed for applicability; the written response was provided, if

required; and the corrective action taken was adequate. The following IE Bulletin was reviewed:

Unit 1

IE Bulletin No.83-03: Check Valve Failures in Raw Water Cooling Systems of Diesel Generators. This Bulletin requested that the licensee:

-- Review the Pump and Valve In-Service Inspection (ISI) Program and modify it, if necessary, to include check valves in the flow path of cooling water for the diesel generators from the intake to the discharge.

-- Examine the ISI program and modify it, as necessary, to include verification procedures that confirm the integrity of the valve internals. This may be accomplished by disassembly and inspection, forward and reverse flow testing, or other equally effective means of insuring valve integrity.

-- Perform and complete initial valve integrity verification procedures for the identified valves by the end of the next refueling outage after April 1, 1983.

-- Report to the NRC, within 90 days of the date of the Bulletin, which valves were identified and the valve integrity verification methods and schedule.

-- Report the results of the initial valve integrity verification to the NRC within 90 days of completion.

At the time the bulletin was issued, the plant was in an outage to replace recirculation piping. On June 14, 1983, the licensee responded to IE Bulletin with the following information:

-- Two check valves were identified in the cooling water line for each of the two emergency diesels. Check valves 72-69 and 72-68 are upstream of diesels 102 and 103, respectively, and check valves 72-67 and 72-66 are downstream.

-- Valves 72-68 and 72-69 were disassembled, inspected and reassembled. Both valves were found to be in satisfactory physical and operating condition.

-- The integrity of valves 72-66 and 72-67 was proven during a forward and reverse flow test.

In a June 14, 1983 letter, the licensee committed to perform quarterly forward and reverse flow tests on valves 72-66 and 72-67 and to disassemble and inspect valves 72-68 and 72-69 once each refueling outage.

On December 10, 1984, the licensee submitted a revision to the response of June 14, 1983. In the revision, the licensee changed the commitment for frequency of forward and reverse flow tests of check valves 72-66 and 72-67 from quarterly to once each refueling outage. Justification for the change was that disassembly and inspection of valves 72-68 and 72-69 once each outage, also required forward and reverse flow testing of valves 72-66 and 72-67. The licensee desired to minimize the adverse effects of draining the service water lines more often than necessary.

The inspector verified that:

-- The four valves identified in the licensee's response were the only valves applicable to IE Bulletin 83-03.

-- The four valves were added to the Inservice Test (IST) Program on October 26, 1983, and the IST program was revised on May 31, 1985 to reflect the licensee's updated response.

-- Valve integrity was verified in the 1983, 1984 and 1986 refueling outages.

-- No failures or unsatisfactory performance of the valves have been identified by the licensee during testing or operation.

The licensee has satisfied all requirements of IE Bulletin 83-03. This Bulletin is closed.

9. Licensee Action on IE Information Notice 87-08:

On February 17, 1986, the licensee notified the resident inspectors that two Emergency Condenser DC Isolation Valves at Nine Mile Point Unit 1 were potentially not Environmentally Qualified (EQ). During a followup on IE Information Notice 87-08, licensee records revealed that the valve motor operators, supplied by Rockwell with DC motors manufactured by Peerless-Winsmith, had motor serial numbers matching those in the IE Notice. A licensee inspection in May 1986 revealed cream-colored insulation with no insulation markings. Inspector review of the documentation revealed that the inspection was documented using an out-of-date procedure and was not signed off. The licensee indicated that the inspection was for information only and was not required. Further information provided to the licensee by NRR indicated that the suspect insulation was a orange colored, wrap-on type Nomex-Kapton insulation. As a result, the licensee concluded that the Emergency Condenser DC Limitorque valve actuators did not contain the insulation which was the subject of the IE Notice.

The licensee also discovered that two DC Limitorque Reactor Core Isolation Cooling (RCIC) valves at Nine Mile Point Unit 2 may have Nomex-Kapton insulation. The licensee placed sleeve-type insulation over the suspect wire in the RCIC valve motor operators to prevent insulation breakdown.

Samples of all three types of insulated wire, used by the vendor for different motor operators, were sent to Wyle Laboratories for testing on February 20, 1987. Wyle Laboratories performed testing and certified all three types of wire as EQ. The inspectors will review the EQ Certification Report in a future inspection.

No discrepancies were identified.

10. Emergency Diesel Generators - Unit 2

a. On October 24, 1986, at the Zion Unit 1 nuclear facility, a catastrophic failure of the 1B Emergency Diesel Generator (EDG) occurred as a result of a maintenance error. The error involved insufficient torque applied to articulated rod crank pin bolts due to a procedural error. The EDG which failed was the same type Cooper-Bessemer KSV series EDG as installed at Unit 2.

The inspector provided the licensee with information concerning the Zion Unit 1 EDG failure for their review. The licensee promptly conducted a review of the applicable EDG maintenance procedures and compared all torque values with the Cooper-Bessemer manual specifications. All torque settings were determined to be the same, with one exception. The licensee's EDG maintenance procedure N2-MSP-EGS-R002 stated that the head frame to crankcase bolts were to be torqued to 30 ft-lbs vice 40 ft-lbs as specified in the vendor manual.

The inspector verified that the maintenance procedure was revised and determined that the licensee had received written confirmation from the vendor that continued EDG operation with 30 ft-lbs torque on the head frame to crankcase bolts would not affect safe operation.

b. On December 23, 1986, at the Palo Verde Unit 3 nuclear facility, a catastrophic failure of a Cooper-Bessemer EDG occurred as a result of the mechanical failure of a piston master rod. The rod failure was the result of overstressing a section of the rod that had been inadequately machined and subsequently repaired using a method of flash coating the affected area with iron plating.

The inspector determined that the EDG vendor had identified one rod used in the Division II EDG which had been improperly machined and repaired using the iron plating process. The vendor did not recommend rod replacement because the repair was in a low stress area of the rod, unlike the rod which failed at Palo Verde Unit 3. Upon further review, the licensee decided to replace the repaired rod to eliminate any potential for rod failure.

During the week of February 8, 1987, the licensee conducted the replacement of the Division II EDG, position No. 4 master rod. The inspectors witnessed portions of the replacement activities and noted satisfactory work practices and comprehensive Quality

Control oversight. Post-maintenance testing was also observed to be satisfactory.

No violations were identified.

11. Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of this inspection. Based on the NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain Safeguards or 10 CFR 2.790 information.