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REGION III

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Report No: 50-254/96012, 50-265/96012

Licensee: Commonwealth Edison Company (ComEd)

Facility: Quad Cities Nuclear Power Station, Units 1 and 2

Location: 22710 206th Avenue North
Cordova, IL 61242

Dates: August 23 - September 23, 1996

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EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/96012, 50-265/96012

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a four week period of inspection.

Operations

- The licensee inappropriately invoked Generic Letter 87-09 guidance in lieu of following Technical Specification requirements for an apparent missed surveillance test (Section O1.2).

- Operators were not knowledgeable of the calibration characteristics of the EHC pressure transducer. This resulted in a plant transient. Operators manually scrammed Unit 1 when an administrative limit for reactor vessel water level was exceeded (Section O1.3).

- The inspectors observed a lack of sensitivity to potential seismic hazards. One non-cited violation (NCV) was identified (Section O2.1 and O2.2).

- Operators inadvertently drained the Unit 2 alternate 125 volt battery due to a knowledge deficiency. This reduced 125 VDC system redundancy (Section O4.1).

- Operators did not recognize that Reactor Core Isolation Cooling condenser drain valves were responding as expected during system testing (Section O4.2).

Maintenance

- Failing to measure critical dimensions of parts associated with two safety-related components rendered safety-related equipment inoperable. One violation was identified (Section M1.2).

- Failure to implement station procedure resulted in workers nearly striking a buried electrical line during excavation (Section M1.3).

- The inspectors identified several examples of inadequate post maintenance tests, including one example of a violation, and considered this to be a weakness (Section M1.4).

- Post-outage restart of Unit 1 was complicated by maintenance related equipment problems (Section M2.1).

Engineering

- Engineering's initial investigation of broken reactor building blowout panel hold down bolts was not rigorous. Engineering did not believe an operability assessment of the condition was necessary until a review by Site Quality Verification (SQV) questioned the degraded condition (Section E1.1).

- Vendor manual instructions for insulating an automatic depressurization system valve were not provided to insulators. The excessive heat resulted in a pressure switch failure and an electrical ground (Section E2.1).

- The licensee and inspectors independently identified important-to-safety motor operated valves which were susceptible to spring pack hydraulic lock (Section E2.2).

- The inspectors identified an NCV associated with the licensee's local leak rate test program (Section E3.1).

Plant Support

- Radiological response to a spill of resin in the truck bay was good (Section R1.1).

Report Details

Summary of Plant Status

Operators started up Unit 1 on August 24, 1996. On August 25, operators manually scrammed the unit due to a rapid rise in reactor water level caused by an unplanned opening of the main steam bypass valves. Unit 1 was restarted and synchronized to the grid on September 6. After four days of operation, the generator was brought off-line while the licensee conducted repairs on a faulty moisture separator drain tank level control valve. Unit 1 was again synchronized to the grid late on September 10. As the inspection period ended, Unit 1 was at or near full power with power ascension testing nearing completion.

Unit 2 was synchronized to the grid on August 15, and operated at or near full power throughout this inspection period.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations.

During the inspection period, several events occurred which required prompt notification of the NRC pursuant to 10 CFR 50.72. The events and dates are listed below.

August 23	Emergency Notification System (ENS) call. Secondary containment inoperable prior to May 10 due to broken reactor building blowout panel hold down bolts.
August 24	Operators took Unit 1 critical.
August 25	ENS call. Operators manually scrammed Unit 1 due to high reactor water level caused by all turbine bypass valves opening while attempting to adjust pressure regulation.
August 25	Operators took Unit 1 critical.
September 1	Operators synchronized and loaded Unit 1 to the grid.
September 2	Operators removed Unit 1 from the grid due to problems with closure times of "D" main steam isolation valve.
September 4	ENS call. The licensee entered and exited an unusual event due to surveillance tests not performed when Unit 1 mode changed from run to startup (Call later retracted).

[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

September 6	Operators synchronized and loaded Unit 1 to the grid.
September 7	ENS call. Booster fans for the single safety-related train of control room ventilation failed to start.
September 10	Operators removed Unit 1 from the grid for removal of foreign material from a moisture separator drain level control valve. Unit resynchronized to grid following material removal.

The inspectors noted operations management inappropriately used generic letter guidance in lieu of following technical specifications when a surveillance test was believed to have been missed. Operators exhibited knowledge weaknesses regarding:

- operating characteristics of the electro-hydraulic control system at low pressures,
- shutdown operation of the alternate battery trickle charger, and
- operation of reactor core isolation cooling system (RCIC) turbine during overspeed testing.

The inspectors noted operators were repeatedly challenged by equipment performance problems during Unit 1 startup. However, control room operators appropriately shut down Unit 1 when an administrative limit was exceeded. The inspectors identified a lack of sensitivity to potential seismic hazards in the facility.

O1.2 Inappropriate Use of Generic Letter (GL) 87-09

a. Inspection Scope (71707)

The inspectors reviewed the licensee's decision to invoke the guidance of GL 87-09, "Sections 3.0 and 4.0 of the Standard Technical Specifications on the Applicability of Limiting Conditions for Operation and Surveillance Requirements," after operators identified that two reactor protection system (RPS) surveillances had not been performed. The inspectors spoke with operators and plant management and reviewed the applicable procedures for the required surveillance tests.

b. Observations and Findings

To allow work to be performed on an inboard main steam isolation valve (MSIV), operators placed the mode switch from "Run" into "Startup/hot standby" position on September 2 at 1:42 p.m. At approximately 10:00 a.m. on September 3, 1996, with core thermal power at approximately 8 percent, operators identified that functional tests for the RPS average power range monitor (APRM) high flux (15 percent) and intermediate range monitor (IRM) inoperative trip systems had not been completed prior to entry into startup/hot standby. Because the operators could not find evidence that the functional tests had been performed within the last week, they made a conservative decision to declare the two RPS trip functions inoperable. With these trip systems

inoperable, the licensee entered into a limiting condition for operation (LCO) action statement which required insertion of all operable control rods within four hours. The shift engineer contacted regulatory assurance personnel to determine the time allowed to perform missed surveillance tests.

Regulatory Assurance believed provisions of GL 87-09 were applicable and informed the shift engineer of a 24 hour grace period allowed to perform overdue or missed surveillance tests. Actions required by the technical specification (TS) were not implemented. Instrument maintenance (IM) technicians completed the required surveillance tests for IRM inoperative and the APRM functional test. The licensee declared the functions operable on September 3 about 7:00 p.m.

When the inspectors were informed of the application of GL 87-09 on September 3, they immediately expressed concerns to the licensee about the appropriateness of waiving a TS action statement. Plant management reviewed the issue, and later concluded that the generic letter guidance should not have been used. As a result, operators determined the plant had entered Emergency Action Level MU10 - "Technical Specifications Time Limit Expired," because the TS LCO action had not been completed within the required time. On September 4, 1996, at 1:25 p.m., the licensee made an ENS phone call declaring an Unusual Event (UE). This UE was terminated during the same call since the situation no longer existed.

Generic Letter 87-09 encouraged licensees to apply for TS improvements, including a provision to allow a 24 hour period to perform overdue or missed surveillances before taking the actions otherwise required in the LCO action statement. However, the licensee had <u>not</u> incorporated this TS change into the current Quad Cities Technical Specifications. The change had been included in the Quad Cities Technical Specification Upgrade Program (TSUP), but the TSUP was not in effect.

Subsequently, the licensee discovered that both the APRM high flux scram and IRM inoperative functions were not required to be tested for entry into startup/hot standby mode. The technical specifications required the functions to be operable, but did not require the functions to be tested to verify operability. The licensee retroactively declared the RPS trip functions operable. The licensee retracted the ENS notification and planned to submit a licensee event report (LER).

c. <u>Conclusion</u>

The inspectors concluded the licensee's use of GL 87-09 was inappropriate. The inappropriate use of GL 87-09 guidance resulted in failure to take what the licensee understood to be the required TS actions. This failure is of significant concern; the NRC expects licensees to adhere rigorously to technical specifications, not to seek for means to avoid or defer required actions.

01.3 Operators Manually Scram Unit 1 Due to High Water Level

a. Inspection Scope (71707)

At 4:48 a.m. on Saturday, August 25, operators manually scrammed Unit 1 when high reactor water level was experienced during startup. The inspectors reviewed licensed operator actions, reviewed pertinent instrument recordings, spoke to licensee staff and management, and developed an independent assessment of the cause of the event. The inspectors reviewed Sections 7.7.4, 7.7.6, and 10.4.4 of the updated final safety analysis report (UFSAR) while reviewing this event.

b. Observations and Findings

Unit 1 had been taken critical on August 24, 1996, and the post outage power ascension procedure was being followed. Operators had increased reactor pressure to an indicated value of approximately 120 psig by pulling control rods. The operators had set the Electro Hydraulic Control (EHC) pressure regulator to 150 psig. This was the bottom of the indicated scale, but the operators had been trained, and the startup procedure stated, that reactor pressure would be controlled at approximately 140 psig with this setting. A mechanical vacuum pump was drawing a vacuum on the condenser, but operating conditions had not yet been reached so automatic interlocks (permissives) were locking out any open signals to the turbine bypass valves (BPV). This feature protected the condenser from over-pressurization.

The operators expected the vacuum pumps to draw the condenser down to its operating range so that the BPV interlock (permissive) would clear. Once operating vacuum was established in the condenser, the operators planned on pulling more control rods until the EHC system was maintaining reactor pressure at approximately 140 psig with one bypass valve fully open.

The condenser reached the operating vacuum range at 4:46 a.m. At the same time, all nine TBVs opened. The rapid opening of the TBVs caused reactor pressure to decrease from about 125 psig to about 45 psig, and then to steady out at 105 psig. Power, initially in the intermediate range, was not affected by the surge. Indicated reactor water level increased toward the administrative limit due to swell in the core. The operators manually scrammed the unit as the water level reached the administrative limit. All rods inserted, and post trip response was as expected.

During the post trip investigation, plant engineering determined that the nine TBVs opened because of an EHC demand signal. The EHC demand was the result of the response characteristics of the turbine inlet pressure transducer at low pressures. This transducer provided the input into the EHC which was compared to the set point value. At low pressures, the installed pressure transducer measured steam line

pressure as being greater than its actual value by up to 67 psig. As a result of the inaccurately high input pressure, the EHC system called for maximum BPV flow. This EHC demand resulted in the BPVs opening when the condenser vacuum permissive cleared.

The licensee concluded the root cause of this event was an inadequate procedure. Corrective actions included:

- QCGP 1-1, "Normal Unit Startup," will be revised to ensure condenser permissive would be satisfied prior to lowering EHC pressure set

- Revising operator lesson plans to include details of this event

- Discussing this event with appropriate engineering and operating personnel.

The inspectors independently reached a different conclusion about the root cause of this event. The inspectors noted that QCGP 1-1 contained a caution statement that TBVs would open if the pressure regulator setpoint was below reactor pressure and condenser vacuum permissive was satisfied, as was the case in this event. The inspectors also noted that the issue of the appropriate EHC set point for maintaining reactor pressure at 140 psig had been raised during operator training, but an incomplete understanding of the EHC system transducer, and its nonlinear output at low pressure, led to incomplete understanding. Based upon these observations, the inspectors concluded that the root cause of this transient was inadequate operator knowledge.

The inspectors determined that no NRC requirements were violated during this event.

c. Conclusions

The inspectors independently reached a root cause determination which differed from the licensee's. The inspectors considered the licensee's corrective actions adequate to prevent a reoccurrence, despite the differing view of the root cause. The inspectors considered the operator's lack of knowledge about the EHC systems nonlinear response at low pressures to be a weakness.

The inspectors concluded the equipment operated in accordance with UFSAR design. The inspectors noted operators quickly responded to the condition and manually scrammed Unit 1 before an administrative limit for reactor vessel water level was reached. The actions taken by operators were the actions management expected when the administrative limit for reactor water level was reached.

01.4 Observation of Unit 1 Startup and Power Ascension Test Activities

a. Inspection Scope (71711)

The inspectors observed tests in progress, monitored plant parameters, attended prework briefings, spoke to operating personnel and test directors, and monitored plant parameters during the Unit 1 startup and power ascension following a refuel outage.

b. Observations and Findings

The licensee developed a power ascension test schedule to test specific components prior to or during the unit's return to full power. Site quality verification (SQV), operations management, and senior station management provided around-the-clock oversight of Control Room activities during the startup.

Problems were experienced in setting the RCIC turbine overspeed trip mechanism. Repeated turbine starts were required, and this led to unexpectedly high temperatures in the RCIC drain tank. The licensee attributed the difficulties to lack of experience on the part of the technicians, and to new, more stringent, set point test criteria. The licensee ultimately utilized vendor assistance in making the overspeed trip adjustments.

During high pressure coolant injection (HPCI) system testing, the turning gear failed to fully disengage on a number of occasions. This required additional operator entries into the HPCI room to manually complete the disengagement. The operating procedure directed the operator to verify disengagement, followed by manual disengagement if necessary. While not questioning the validity of this procedure step, the inspectors were concerned that operators appeared to accept the improper turning gear operation as a normal condition. When the inspector questioned this, shift management submitted an action request (AR) to repair the mechanism.

Initial "fail safe" testing of the 1D MSIV using an interim procedure (IP) was unsuccessful. This test verified MSIV closure within a specified time on loss of system control air. The vent flow path directed by the IP did not allow sufficient venting of the actuator air pressure. The valves failed to close as required because of the trapped volume of air. The operating crew found the discrepancy and obtained a correction to the procedure.

An example of conservative decision making was demonstrated on one occasion when the operating shift elected not to take the safe shutdown makeup pump (SSMP) out of service since it would increase both units' risk factor.

c. Conclusions

There was inadequate research and review in development of the interim procedure used to conduct the 1D MSIV fail safe test. There were also deficiencies in system and equipment knowledge and acceptance of degraded HPCI conditions for a small percentage of the total number of tasks in the test program. The incidents described above were some examples of things that did not proceed as planned on the first attempt. When something did not go as expected during the work that the inspectors observed the job was stopped, the plant was verified to be in a safe condition, assessment and evaluation were performed and the correct course of action was appropriately determined prior to continuing. Briefings were generally interactive and thorough. In most cases, plant operators exhibited good procedure adherence and effective self-checking.

O2 Operational Status of Facilities and Equipment

O2.1 Effect of Movable Shielding Racks on Plant Equipment

a. Inspection Scope (71707)

The inspectors identified movable shielding racks which were positioned less than the height of the racks away from scram solenoid valves in Unit 2. Unit 2 was shut down at the time. The inspectors reviewed the generic shielding package which installed the shielding for seismic adequacy.

b. Observations and Findings

Licensee administrative procedure QCAP 0640-01, "Installation and Control of Shielding," Attachment J, step 8, required that mobile shield racks be kept the height of the rack plus 1 foot away from safety related equipment. The inspectors identified a "generic" shielding package installed on movable racks that was less than the height of the racks away from scram solenoid valves in Unit 2. This was discussed with the shielding coordinator, who expressed a reluctance to write a PIF, indicating a PIF would just be assigned back to him and he already knew about the problem and was correcting it. The inspectors discussed this issue with licensee management. Management informed the inspectors that the shielding was removed, and that PIF 96-2328 has been written to document the condition. The shielding coordinator was instructed to document discrepant conditions on PIFs.

As additional action, the licensee changed QCAP 640-01, Attachment J, into a checklist which must be completed by the shielding engineer and included in the shielding package. Additionally, system engineering was required to identify safety-related equipment in the vicinity of the generic shielding installation to ensure adequate distance from the shielding to the safety-related equipment.

c. Conclusions

Failure to keep the mobile shielding the required distance away from the scram solenoid valves was classified as a **Non-Cited Violation (NCV 50-254/265-96012-01)** consistent with Section IV of the NRC Enforcement Policy, because minimal safety significance; the control rods were fully inserted, and latched, during the period that the temporary shielding package was installed.

O2.2 Staff Seismic Awareness During Dual-Unit Outage

a. Inspection Scope

During the inspection period, the inspectors conducted multiple tours of Units 1 and 2 to determine the effectiveness of the licensee's seismic housekeeping program.

b. Observations and Findings

In addition to the mobile shielding racks noted in section O2.1, the inspectors noted other examples of items not secured or restrained to prevent undesirable interaction with plan equipment. Examples included:

- an inadequately secured mobile tool box within a few feet of Unit 1 safety-related breaker panels;
- an unsecured 10-foot step ladder in Unit 2 residual heat removal service water vault;
- numerous examples of breakers removed from, but left standing between, safety related electrical panels;
- an "MG Set Toolbox" on the turbine deck, within 6 inches of the 1A recirculation motor-generator set control panel, which rolled freely despite having a stop-block in place;
- unsecured hoists that could swing and hit safety-related equipment.

These, and other examples, were discussed with licensee management during the period. Licensee management took action to address the individual findings, and included an article on seismic awareness in the site daily newsletter. The licensee also initiated an engineering evaluation of the current processes used to prevent damage during a seismic event.

The inspectors noted good improvement in control and restraint of equipment during the latter part of the inspection period.

c. Conclusions on Seismic Awareness

The inspectors found the seismic awareness practices of licensee personnel to be weak, and several examples of poor practices were identified by the inspectors. The licensee took action to address the inspectors' observations, and initiated an engineering evaluation to identify appropriate long term actions.

02.3 Control Room Ventilation Booster Fans Fail to Start

On September 7, 1996, operators attempted to start the safety-related control room emergency ventilation system (CREVS). However, the booster fans failed to start. This rendered the CREVS inoperable. The licensee made an ENS notification due to the failure of a single train safety system to operate.

The licensee's investigation into the root cause of the booster fan failures was not complete at the end of the inspection period. The inspectors consider this an **Unresolved Item (URI 50-254/265-96012-02)** pending completion of the licensee's investigation into the cause of the problem, and the NRC's review of the results.

04 Operator Knowledge and Performance

04.1 Unit 2 Alternate Battery Discharged

a. Inspection Scope (37551)

The licensee identified that one alternate 125 VDC battery no longer functioned on August 26, 1996. The alternate battery in each unit is used to supply loads during required testing of the safety-related station battery, but the alternates are non-TS equipment. The inspectors observed maintenance activities associated with replacement and testing of the nonfunctional battery, reviewed applicable procedures, and spoke to engineering and maintenance personnel. The inspectors reviewed the completed battery surveillance tests and battery service test results to ensure compliance with TS 3/4-9.C and UFSAR section 8.3.2.2.

b. Observations and Findings

On April 10, 1996, operators noted that the supply breaker to the trickle charger for the Unit 2 125 VDC alternate battery would not close. Operators left the supply breaker open, but the breaker from the out of service battery charger to the alternate battery bank was left closed. An action request was submitted to repair the charger. With the charger not functioning, operators stopped making weekly checks of the Unit 2 alternate battery's condition. Although not required, the weekly checks would have detected battery degradation.

On August 26, electricians completed repair of the trickle charger and placed the charger back in service. However, the battery failed to accept the charge. Engineering concluded that the battery had been drained through the failed trickle charger. This rendered the battery non-functional. Subsequent attempts to recover the battery were unsuccessful. Because a Unit 2 station battery test needed to be done, the licensee replaced 58 failed Unit 2 alternate battery cells with cells from the Unit 1 alternate battery. The licensee then successfully tested the Unit 2 alternate and station batteries. New cells were ordered for the Unit 1 alternate battery.

The UFSAR Section 8.3.2.2 stated that there were two 125 VDC batteries for each unit, plus an alternate battery not normally connected to essential loads. The alternate battery existed to allow for on-line testing of the normal 125 VDC battery, and to supply system loads upon failure of the normal battery, by means of manual connections. The alternate 125 VDC batteries were described as having the same capacity as the normal batteries.

c. Conclusions

The inspectors concluded that licensee personnel did not know that leaving the breaker between the battery trickle charger and the battery closed would result in the battery losing its charge. Loss of the Unit 2 battery, and subsequent transfer of cells from Unit 1 to Unit 2, resulted in some loss of redundancy in the 125 VDC systems . Essential loads were not affected by these conditions, and the requirements of TS 3/4-9.C were satisfied. However, Unit 1 lacking an alternate battery is not currently consistent with the UFSAR description. Pending further review of the detailed circumstances which caused this condition, and evaluation of the licensee's actions and reviews concerning applicability of 10CFR50.59, this is considered an **Unresolved Item (URI 50-254/265-96012-03).**

O4.2 Operator Response to Reactor Core Isolation Cooling (RCIC) Testing

a. Inspection Scope (92901)

While observing control room activities during startup, the inspectors witnessed operators abort RCIC overspeed testing when a high RCIC barometric condenser level alarm was received. The inspectors reviewed the licensee's evaluation of the cause of the high level alarm, and independently assessed the operators response to the alarm.

b. Observations and Findings

On August 26, 1996, while performing overspeed testing on the Unit 1 RCIC turbine, a RCIC gland seal vacuum tank high level alarm was received. The RCIC barometric condenser isolation valves (air-operated valves AO-1301-12 and 13) were addressed in the annunciator procedure (QCAN 901(2)-4-H-15, revision 1) which required verification that the drain valves were open. The operator was also unable to open the valves with the control switch. The operator tripped the RCIC turbine and troubleshooting efforts were started. The valves were stroked and determined to be free of possible binding or air operating system malfunctions. After further reviews of the electrical prints, the operators determined that the valves operated correctly, they should not have opened. The valves were interlocked with the RCIC turbine steam inlet valve (motor-operated valve 1301-61).

Plant drawings existed for the operators to have understood the response of the valves. Both the piping and instrumentation drawing and electrical print for RCIC noted the existence of the interlock.

Additionally, the operator's training provided the information to understand the valve response. The RCIC training synopsis for initial license and licensed operator continuing training (LIC-1300 module, revision 3) described the functions of the drain valve and the interlock to the steam inlet valve.

The licensee took corrective action to change the annunciator procedure so that the interlock and its effects on the drain valves were clearly specified.

c. Conclusions

Annunciator Procedure QCAN 901(2)-4-H-15 did not accurately reflect plant design, and contained an instruction which it was not possible to implement in some circumstances. This was contrary to the requirements of 10CFR50, Appendix B, Criterion V, that activities affecting quality be conducted pursuant to documented procedures which are appropriate to the circumstance. This is considered a **Violation (VIO 50-254/265-96012-04)**.

The inspectors concluded that the operator's actions to abort the RCIC test were conservative. In addition, the inspectors concluded that this event demonstrated a deficiency in the operator and operating shift's knowledge of the system, similar in nature to the weakness identified in Section O1.3 of this report.

O7 Quality Assurance in Operations

O7.1 Drywell Inspections (Unit 2) (71707, 40500)

Inspection Scope

The inspectors accompanied a unit supervisor on a tour of the Unit 2 drywell prior to startup of Unit 2.

Observations and Findings

The material condition of the drywell was generally good. However, the lower levels of the drywell had not been cleaned after the completion of all scheduled work activities. The inspectors identified tools and numerous other small items scattered on the floor. These items included: tags; radiological smear papers; and small pieces of lagging, flashing, and tape. A large piece of steel (about 1 foot square with a flange half that size) had been left on one of the upper levels. The inspectors also identified trash on top of the downcomers behind the spray shields. The unit supervisor considered the lower level to not be ready for closeout.

Additional cleaning was completed prior to drywell closeout and Unit 2 startup.

Conclusions

The cleanup of the drywell prior to reactor startup was inadequate. The kind, quantity, and location of items found during the initial closeout tour by the inspectors and the licensee indicated that several station departments were responsible for the poor housekeeping. The subsequent drywell entry to correct this problem delayed reactor startup and resulted in additional dose to personnel.

08 Miscellaneous Operations Issues (92700)

08.1 (Closed) LER (50-265/94009 and 50-265/94009-01): Drywell Interlock Door Failure. During startup, operators entered into the Unit 2 drywell to investigate the source of leakage. During a trip through the drywell interlock doors, the inner door failed to latch closed, preventing the outer door from opening. Tools and a procedure provided in the airlock allowed operators to defeat the interlock for about 32 minutes to allow trapped operators to exit the drywell. The licensee performed a detailed diagnostic inspection of the airlock doors and made necessary repairs. Based upon the inspection findings, the licensee developed a preventative maintenance (PM) procedure (QCMPM 1600-02, "Drywell Personnel Interlock PM"). The inspectors reviewed the licensees corrective actions and the new PM procedure and concluded that this item should be considered closed.

08.2 (Closed) Unresolved Item (50-254/265-96002-05): Residual Heat Removal Service Water (RHRSW) Pump Start Anomalies. The licensee investigated abnormal alarms received during start of Unit 1 RHRSW pump. The investigation determined the operator must have started an RHR pump in lieu of an RHRSW pump. The operator was disciplined and this event was discussed with the operating crews. This event was contrary to TS 6.2.A.1, since QCOS 1000-4, "RHRSW Quarterly Flow Rate Surveillance," was not properly implemented. This licensee-identified and corrected violation is being treated as a **Non-Cited Violation (NCV 50-254/265-96012-05)** consistent with Section VII.B.1 of the Enforcement Policy. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General (62703)

The inspectors identified the following weaknesses in the maintenance program:

- procedures failed to require verification of critical dimensions within safety-related equipment,
- adequate post-maintenance tests were not always performed, and
- personnel failed to adhere to procedures.

M1.2 Failure to Measure Critical Dimensions

a. Inspection Scope (62703)

The inspectors spoke with vendor and licensee personnel, reviewed maintenance practices and procedures, and reviewed UFSAR Section 6.2.4.

b. Observations and Findings

i. Unit 1 "D" Main Steam Isolation Valve (MSIV) Slow Closure

The licensee replaced various components on all MSIV inboard control manifolds during the Unit 1 outage. The manifold assemblies were rebuilt in March 1996.

During performance of surveillance test QCOS 250-04, "MSIV Closure Timing," the Unit 1 "D" inboard isolation valve (1-203-1D) failed to close within the time limits required by UFSAR 6.2.4.1. Engineering staff, with vendor assistance, determined that a solenoid valve on the control manifold was malfunctioning. The licensee disassembled the solenoid and determined that the plunger assembly seating surface was irregular. The vendor representative believed the viton seating surface was not machined during the manufacturing process. Neither the vendor nor the licensee had considered this a critical dimension worth measuring prior to assembly into the solenoid valve. Thus, the work package (procedure) for the manifold assembly rebuild had no acceptance criteria relating to this dimension.

The failure to establish appropriate quantitative or qualitative acceptance criteria in the maintenance procedure was considered a **Violation (VIO 50-254/265-96012-06a)** of 10 CFR 50, Appendix B, Criterion V.

Even though the closing times of the other MSIVs were satisfactory, the licensee performed additional testing on them to ensure no other installed plunger assemblies lacked the required machining on the seating surface. Both the vendor and the licensee planned to change procedures to ensure that this critical dimension would be measured.

ComEd placed the affected plunger assemblies in a hold status until the seating surfaces could be inspected. A PIF (96-2676) documented the material deficiency issue. The licensee intended to evaluate the issue for reportability under 10 CFR 21.

ii. Unit 1 "D" Residual Heat Removal Service Water Pump (RHRSWP)

During operation of the 1D RHRSWP on September 7, 1996, the licensee identified that the outboard radial bearing isolator (INPRO™ seal) of the booster pump demonstrated excessive heat (sparks). The pump was declared inoperable and the licensee documented the condition on PIF 96-2702. Engineering staff determined that during the 1D RHRSWP operation, direct contact between the outboard radial bearing isolator (INPRO™

seal) and the rotating shaft sleeve nut created the excessive heat. The licensee attributed the cause of this problem to worker efforts to center the impeller in the pump housing, which had reduced the clearance between the INPRO™ seal and the sleeve nut. This condition was not identified during pump reassembly following the maintenance activity on August 19, nor during pump acceptance testing on August 20 using the approved T/S test procedure. The capability of the pump to perform prolonged service during the period from August 20 to September 7 was indeterminate, but the pump met T/S requirements to be considered "operable" during this period.

The inspectors reviewed work package 940104117-02 and concluded that it lacked acceptance criteria for the gap setting between the INPRO™ seal and the shaft sleeve nut. The failure to establish appropriate quantitative or qualitative acceptance criteria for this gap in work request 940104117-02 maintenance procedure was considered a **Violation (VIO 50-254/265-96012-06b)** of 10 CFR 50, Appendix B, Criterion V.

The 1D RHRSWP pump was repaired and an appropriate gap between the sleeve nut and the INPRO™ seal was established. The licensee-planned corrective actions included performance of an engineering evaluation to allow machining of the sleeve nut for greater freedom in centering the impeller in the pump volute, and the development of a pre-startup checklist for pumps.

c. Conclusions

In the above cases, maintenance instructions did not require verification of critical dimensions required to support proper safety-related equipment operation.

The licensee has had previous problems ensuring properly sized parts were installed in safety-related equipment. In Inspection Report 50-254/265-96011, the inspectors noted similar problems with the Unit 2 "A" control rod drive pump.

M1.3 Workers Contacted a 13.8 kV Line During Excavation

On September 9, maintenance personnel, installing a cathodic protection line, contacted a buried 13.8 kV electrical power line during excavation with a backhoe. This resulted in loss of power to a warehouse and a fire training facility. The personnel involved were not injured and no safety-related equipment was affected. The inspectors reviewed the event in discussions with maintenance management.

Maintenance personnel failed to follow procedure QCGM 307-07, Revision 0, "Excavation, Trenching, and Shoring." Specifically, they failed to locate buried utilities and they failed to manually dig in the vicinity of the buried power cable. After unearthing a warning flag buried to mark the presence of power cable, the workers continued to dig with the backhoe.

Although the excavation did not involve nuclear safety-related equipment, and consequently, adherence to the procedure was not required by NRC regulations, the failure to follow the procedure could have had serious personnel safety consequences.

M1.4 Post-Maintenance Testing Weaknesses

a. Inspection Scope (62703)

The inspectors observed work in the field, reviewed work packages, and spoke to maintenance workers to determine the adequacy of post-maintenance testing.

b. Observations and Findings

In IR 50-254/265-96011, the inspectors documented problems associated with a high pressure coolant injection system check valve, (2-2301-7), which had a 14 gpm body-to-bonnet leak. The leak necessitated shutting down Unit 2. The licensee did not pressure test the valve to verify its integrity prior to Unit 2 startup.

During the Unit 1 outage, workers installed new flow elements in the off gas system. During post-modification testing (PMT), workers tested the transmitter output to the control room recorder. However, there were no PMTs to test the signal from the flow element to the transmitter. During startup of Unit 1, with sparge air directed to the off gas system, operators did not detect flow through the off gas system. The licensee investigated, and determined that the flow element was improperly wired to the transmitter by Modification E04-1-93-244. Engineering issued a field change request (FCR 960326) to correct the wiring problem. Operators later returned the system to service. The inspectors noted that no PIF was generated to document this event. Failure to properly test the flow elements resulted in diverting operator resources from startup activities to system troubleshooting. The lack of appropriate acceptance criteria in the post-modification testing of modification E04-1-93-244 is considered an additional example of a violation (VIO 50-254/265-96012-06c) of 10 CFR 50. Appendix B, Criterion V.

The licensee replaced various components on all MSIV inboard control manifolds during the Unit 1 outage. An improperly machined solenoid plunger assembly on the 1D MSIV control block resulted in the inboard "D" MSIV failing a surveillance test during Unit 1 startup (See Section M1.2). Although the licensee tested the inboard MSIV control blocks after maintenance was completed, the tests did not detect the faulty plunger assembly. Only after simulated heat was applied to the control block did the solenoid exhibit erratic behavior.

c. Conclusions

One violation of NRC requirements was identified; the inspectors noted other weaknesses in early detection of deficient equipment due to the

absence of adequate post maintenance testing. The licensee appeared to rely upon TS surveillance tests and other startup performance indicators to demonstrate the operability of equipment following maintenance activities. The inspectors considered this to be a significant weakness.

M2 Maintenance and Material Condition of Facility and Equipment

M2.1 Equipment Performance During Unit 1 Startup from Refueling Outage

a. Inspection Scope (62707 and 92902)

The inspectors performed observations and reviews of the Unit 1 startup activities, focusing on several system and component failures. The inspectors interviewed appropriate licensee staff to determine the effectiveness of maintenance during the outage and the root causes of the equipment malfunctions during the startup.

b. Observations and Findings

i. Unit 1 RCIC Overspeed Testing

On August 26, 1996, the licensee performed the first of a series of RCIC turbine overspeed tests. These tests were part of the low power startup sequence for Unit 1. During the tests, several difficulties were experienced.

The overspeed tests were the first to be performed with new acceptance criteria which required three consecutive acceptable turbine overspeed trips. The new criteria also required the three trips be free of either a rising or declining trend of the actual trip setting. This change in the acceptance criteria improved the reliability of the overspeed function, a recognized problem area within the Boiling Water Reactor industry.

The RCIC turbine required many attempts before three consecutive non-trending results were achieved. Several factors contributed to the difficulty of passing the criteria. These included:

- The use of a hand-held tachometer. The instrument that was used had a one second sampling rate. This made it difficult to measure the actual trip point because of the rapid acceleration of the unloaded turbine.

- First time overhaul of the turbine. During the refueling outage, the turbine was overhauled for the first time since commercial operation of Unit 1. This resulted in significant changes in the balance and tolerances of the turbine that required fine adjustments during the tests.

- Change in practices. The turbine overhaul was also complicated by a change from the past practice of using contract or vendor

personnel to measure and adjust the turbine clearances. During the Unit 1 refueling outage, less experienced station maintenance personnel performed all maintenance activities.

- The vendor manual instructions were not clear. The manual did not provide detailed instructions for the adjustments of the overspeed trip mechanism. This resulted in over-adjustments that complicated achieving compliance with the non-trending trip criteria.

The inspectors found that lessons learned from the previous Unit 2 RCIC turbine overhaul in 1990 were not applied during the Unit 1 turbine testing. A PIF on the 1990 testing problems had not been written. A PIF documenting the problems and lessons learned from the Unit 1 testing was not written until prompted by the inspector's questions.

ii. Rod Select Matrix

On August 24, 1996, during startup, control rod withdrawal was stopped on two occasions because rods could not be selected. Previous problems had occurred when the rod select matrix select buttons did not make contact, and rods could not be selected. The licensee had initiated a phased replacement of the rod select buttons during this outage. However, a malfunction associated with a replaced select button occurred. Additional investigation by the licensee revealed that the K-1 relay, associated with the select matrix to recognize the selected rod, was also malfunctioning. An additional corrective action was initiated to replace both units K-1 relays.

c. Conclusions

The inspectors compared equipment malfunctions during the recent Unit 1 startup from a refueling outage with equipment malfunctions experienced during the Unit 2 startup from a 1995 refueling outage. The inspectors determined that malfunctions of systems, components, and support equipment occurred during both startups. Although both startups had similar problems due to similar root causes, the 1995 Unit 2 startup did experience more trips, and a rapid manual reduction in power. Most of the 1995 malfunctions were prevented during the Unit 1 startup. However, resolutions of the root causes were not effective in preventing other equipment malfunctions during the Unit 1 startup.

Problem identification documentation and evaluation of the RCIC turbine overspeed testing was not performed by the licensee until prompted by the inspectors. The lessons learned efforts for the rod selection matrix were effective in finding additional problems with the system and initiating corrective actions.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER (50-265/94005): Unit 2 EHC System Leak. On June 21, 1996, an oil leak on the Unit 2 EHC system resulted in a manual reactor scram.

The leak was caused by vibration and resulted in development of a crack on the tube flare connection. Corrective actions were completed, including replacement of the susceptible flare connection fittings at the turbine control valves (for both Units) with a vendor recommended improved fitting. The inspectors considered this item closed.

M8.2 (Closed) LER (50-254/96003): Inadvertent Start of Emergency Diesel Generator (EDG) during Maintenance Activities. Maintenance personnel inadvertently started the Unit 1 EDG due to a procedural deficiency. The licensee changed QCMMS 6600-3, "EDG Periodic Preventive Maintenance Inspection." The inspectors reviewed the licensees procedure change and consider this item closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Reactor Building Blowout Panel Bolts Broken

a. Inspection Scope (37551 and 40500)

The inspectors reviewed documents related to the blowout panels, including UFSAR 6.2.3.2.

b. Observations and Findings

The licensee documented on Problem Information Form (PIF 96-2056) that several reactor building blowout panel (RBBP) bolts were discovered broken. The PIF concluded the apparent cause of the broken bolts was from accidental bumping of the bolts during repair of the reactor building wall in early June. The corrective actions assigned were to install a protective barrier around the bottom row of RBBP bolts. During closeout of this PIF, a site quality verification (SQV) individual questioned engineering about the assigned corrective actions. Engineering informed the SQV individual that other RBBP bolts were identified as broken before the damaging winds on May 10, 1996. This prompted SQV to write PIF 96-2347 and request that engineering verify secondary containment design requirements were met with the RBBP bolts broken.

The engineering evaluation determined that RBBP did not meet all the design requirements specified in Section 6.2.3 of the UFSAR, even though previous secondary containment testing ensured the licensee could meet the required 0.25 inches of water differential pressure required of secondary containment by TS 4.7.C.1. Operations declared secondary containment inoperable and made an ENS call on August 23. The licensee replaced the broken bolts prior to unit startup.

The inspectors consider the operation of the units at power with inoperable blowout panels to be an **Unresolved Item (URI 50-254/265-96012-07)** pending review of the Licensee Event Report (LER).

c. Conclusions

The inspectors concluded that Engineering's initial PIF investigation was not rigorous. Engineering knew that RBBP bolts had been broken prior to May 10, but did not include the information on PIF 96-2056. Engineering did not believe an operability assessment of the condition was necessary until an SQV review questioned the potential degraded condition of the RBBP. A good questioning attitude by SQV prompted engineering to reevaluate the degraded condition for operability.

E2 Engineering Support of Facili ies and Equipment

E2.1 Safety Valve Bellows Rupture Pressure Switch

a. Inspection Scope (37551)

The inspectors reviewed the relief valve vendor manual, spoke to engineering and maintenance personnel, and viewed pictures of the as-found and as-left condition of the 1-0203-3A valve bellows pressure switch.

b. Observations and Findings

During startup of Unit 1, operators verified the proper operation of relief valves at 300 psi steam pressure by opening and closing the valves using a switch located in the control room. Later, operators received an annunciator indicating a failure of the bellows on the "A" safety/relief valve (1-0203-3A). About an hour later, operators received a control room annunciator indicating a ground on the 125 VDC electrical system. Workers narrowed the ground to the 1-0203-3A bellows pressure switch and signal wiring. The pressure switch and wire were located adjacent to the 1-0203-3A valve and inside the valve's insulation. The temperature inside the lagging was in excess of 400 degrees F. The licensee concluded that heat deteriorated the wiring and caused an electrical ground resulting in the ground and bellows failure annunciators in the control room.

The wiring and switch were replaced and insulation was removed from the vicinity of the components to lessen the heat load. The vendor manual specified that the pressure switch not be insulated due to potential heat degradation of the switch.

c. Conclusions

The inspectors concluded that vendor manual instructions for insulating the valve were not provided to the insulators. This resulted in the pressure switch being subjected to temperatures higher than the pressure switch thermal rating. The failed switch produced ground and bellows failure alarms, but the valve remained operable.

E2.2 Hydraulic Lock of Motor Operated Valve Spring Pack

a. Inspection Scope (37551)

The inspectors observed maintenance activities associated with repair of a feedwater system valve operator, reviewed post maintenance valve testing results, and discussed the valve operator with plant engineers.

b. Observations and Findings

During startup of Unit 1, operators noted difficulty opening the "B" feedwater regulating valve (FWRV) isolation valve (1-3206B). Operators determined that the breaker thermal overloads to the valve motor operator had tripped. This condition resulted in the valve traveling fully into the seat and stopping only after the electrical power supply breaker overloaded. Engineering determined the motor operated actuator spring pack experienced a hydraulic lock condition. The licensee performed a weak link analysis and determined the actuator to yoke bolts were over stressed by the event and replaced the affected bolts. An inspection of the actuator and internals revealed no damage to those components. The licensee modified the actuator by adding an external grease relief line and replaced the spring pack with a model not susceptible to hydraulic lock conditions.

Based upon the inspector's observations: the valve engineer appeared knowledgeable and provided assistance and oversight for the troubleshooting and repair work; the workers demonstrated a high degree of skill and efficiency in performing the repair; the job site was orderly; and workers demonstrated proper use of procedures.

The valve engineer reported that all safety-related motor operated valves were equipped with grease reliefs.

c. Conclusions

The "A" FWRV isolation valve in Unit 1 and both Unit 2 FWRV isolation valves had spring packs susceptible to hydraulic lock conditions. The licensee was reviewing other "important to plant operation" valves throughout the plant to determine which valves were susceptible to hydraulic lock of the spring pack, and planned to generate action requests to repair the affected actuators. This item is considered an **Inspector Followup Item (IFI 50-254/265-96012-08)** pending NRC review of the licensee's corrective actions.

E2.3 Facility Adherence to UFSAR

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors compared plant practices, equipment, procedures and/or parameters to those described in the UFSAR, and documented findings in this inspection report. The inspectors reviewed the following sections of the UFSAR:

IR Section	UFSAR Section	Applicability
01.3	7.7.4	Pressure Regulator and Turbine Pressure Control
01.3	7.7.6	Main Condenser
01.3	10.4.4	Turbine Bypass System
04.1	8.3.2.2	125 VDC Battery System
M1.1	6.2.4	Main Steam Isolation Valves
E1.1	6.2.3.2	Reactor Building Blowout Panels

E3 Engineering Procedures and Documentation

E3.1 Failure to Temperature Compensate for Local Leak Rate Testing (LLRT)

a. Inspection Scope (37551)

The inspectors reviewed licensee procedure QCTS 0600-04, "Drywell Personnel Airlock Local Leak Rate Test," and interviewed LLRT personnel.

b. Observations and Findings

The inspectors noted that the licensee did not compensate for temperature readings during pressure decay tests of the two units' drywell personnel air locks. In response to questions from the inspectors, the LLRT coordinator stated the procedure required a 45 minute soak time after pressurization to allow for temperature stabilization. However, this practice would not correct for any externally induced temperature fluctuations that might occur during the test. The LLRT coordinator agreed that temperature measurements should have been part of all pressure decay tests.

Subsequently, the LLRT coordinator determined ANSI/ANS-56.8-1994, applied to 10 CFR 50, Appendix J - Option B, which required temperature compensation during pressure decay tests.

The licensee subsequently generated PIF 96-2687 to address this problem. The personnel airlocks on both units were satisfactorily retested under an IP which included temperature compensation. Other pressure decay LLRT procedures were being revised to include this measurement.

The licensee failed to incorporate ANSI/ANS-56.8-1994 requirements into the licensees LLRT program. The inspectors classified this issue as a **Non-Cited Violation (NCV 50-254/265-96012-09)** consistent with Section IV of the NRC Enforcement Policy.

c. Conclusions

The licensee failed to incorporate applicable requirements into the LLRT procedure. The safety significance of this event was minimal. Past test results indicated that the leakage was well within the allowed limits even without temperature compensation.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Violation (50-254/265-96002-01): Change of Procedural Intent. On February 10, 1996, while the licensee was shutting down Unit 1 for a refueling outage, engineers performed a LLRT on the RHR test return line to the torus. Engineers used procedure QCTS 600-18 "RHRS Suppression Chamber Spray Local Leak Rate Test (MO-1(2)-1001-34A/B, 36A/B, and 37A/B)." Operators used a temporary procedure field change process to allow the procedure to be used in an operating condition rather than in shutdown or refueling conditions. This changed the original intent of the procedure, contrary to requirements of TS 6.2.D.1. Licensee-completed corrective actions included a revision (eight) to QCAP 1100-13 "Processing Procedure Field Change". This revision required a review to verify no change of procedure intent when performing a procedure field change. The inspectors considered the corrective actions adequate.

8.2 (Open) Unresolved Item (50-254/265-96011-05): Reactor Water Cleanup (RWCU) High Energy Line Break (HELB) Scenario. The licensee committed to the NRC to change procedures and provide training to operators to mitigate the potential of a RWCU HELB affecting secondary containment integrity. The inspectors reviewed the licensees actions. Interim procedures (IPs) were issued to QCCP 200-1, "Reactor Water Iodine Analysis," and QCAP 213-02, "Water Chemistry Control," to ensure RWCU would be isolated should reactor water iodine concentration exceed 0.2 uci/gm. Similarly, annunciator procedures were changed to isolate RWCU should either one of the two room temperature detectors alarm. Operators had received training on the issue. This item will remain open pending further NRC review of licensee corrective actions.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Spill of Resin During Transfer

a. Inspection Scope (83729)

The inspectors reviewed an action plan developed to clean up radioactive resin spilled on top of a high integrity shipping container (HIC). The inspectors toured the radiological waste building truck bay and spoke to personnel involved with the resin spill.

b. Observations and Findings

On September 14, 1996, the licensee was completing transferring radioactive resin from the radiological waste mixing tank to the HIC. During disassembly of the resin transfer equipment, operators observed resin on top of the HIC. This was an unexpected condition. Operators stopped disassembly of equipment and notified radiological controls management of the condition. To prevent spread of contamination, workers secured ventilation and covered the top of the HIC with plastic.

The truck bay was controlled as a locked high radiation area. The licensee implemented an action plan to clean the top of the HIC and install the lid.

At the end of the inspection period, the licensee had successfully cleaned the top of the HIC, installed the lid, and released the truck bay from a locked high radiation area status.

c. Conclusions

Actions taken by radiological protection in response to the spill were good. The licensee had not yet determined how the spill occurred. The inspectors consider this an **Unresolved Item (URI 50-254/265-96012-010)** pending review of the licensee's corrective actions and root cause evaluation.

R8 Miscellaneous Radiation Protection and Control Issues (83729)

R8.1 (Closed) Unresolved Item (URI) 50-254/265-96006-07: Apparent Radiation Protection Violation by a Contract Worker. Licensee staff observed a worker whose foot was not properly positioned on a radiation detector at the boundary of the radiologically controlled area. Technical Specification 6.11 required that procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20, and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure. Quad Cities procedure QCRP-5822-7, "Operation and Calibration of the IPM-7/8 Whole Body Monitors," step G.1(b)(2), required proper foot placement in the detectors. The licensee's investigation determined that the contract worker, contrary to these instructions, attempted to circumvent the monitor by turning his foot such that it was not over the detector during a whole body frisk.

The inspectors reviewed the licensee's investigation of this incident and concluded that it was thorough and that actions taken by management were appropriate. These actions included taking disciplinary action against the individual, who had no prior procedure adherence problems, and discussing the event in the station newsletter. The contracting firm also developed a corrective action plan which included discussing the event with other contract workers and stressing the importance of adhering to plant procedures.

This licensee identified and corrected violation is being treated as a **Non-Cited Violation (NCV 50-254/265-96012-11)**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 23, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

ComEd

E. Kraft, Site Vice President
D. Cook, Operations Manager
J. Hutchinson, Engineering Manager
W. Lipscomb, Work Control Superintendent
C. Peterson, Regulatory Affairs Manager
F. Tsakeres, Radiation Chemistry Superintendent
M. Wayland, Maintenance Superintendent

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 62703: Maintenance Observation
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71711: Plant Startup after Refueling
IP 83729: Occupational Exposure During Extended Outages
IP 92700: Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901: Followup - Operations
IP 92902: Followup - Engineering
IP 92903: Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/265-96012-01	NCV	movable shielding racks not per procedure
50-254/265-96012-02	URI	control room ventilation booster fans fail to start
50-254/265-96012-03	URI	Unit 1 lacks alternate battery described in SAR
50-254/265-96012-04	VIO	annunciator procedure not appropriate to circumstances
50-254/265-96012-05	NCV	residual heat removal service water pump start anomalies
50-254/265-96012-06a	VIO	Unit 1 "D" MSIV slow closure; inadequate procedure
50-254/265-96012-06b	VIO	Unit 1 "D" RHRSWP inoperable; inadequate procedure
50-254/265-96012-06c	VIO	off gas flow detection inoperable; inadequate procedure
50-254/265-96012-07	URI	reactor building blowout panel bolts broken
50-254/265-96012-08	IFI	hydraulic lock of MOV spring pack
50-254/265-96012-09	NCV	failure to temperature compensate for LLRT
50-254/265-96012-10	URI	spill of resin during transfer
50-254/265-96012-11	NCV	radiation protection violation by a contract worker

Closed

50-265/94009	LER	drywell interlock door failure
50-265/94009-01	LER	drywell interlock door failure
50-254/265-96002-05	URI	RHRSW pump start anomalies
50-265/94005	LER	EHC system leak
50-254/96003	LER	inadvertent start of EDG during maintenance activities
50-254/265-96002-01	VIO	change of procedural intent
50-254/265-96006-07	URI	apparent radiation protection violation by a contract worker

Discussed

50-254/265-96011-05	URI	RWCU HELB scenario

LIST OF ACRONYMS USED

APRM	-	Average Power Range Monitor
AR	-	Action Request
CFR	-	Code of Federal Regulations
CREVS	-	Control Room Emergency Ventilation System
EDG	-	Emergency Diesel Generator
EHC	-	Electro-Hydraulic Control System
ENS	-	Emergency Notification System
FME	-	Foreign Material Exclusion
FWRV	-	Feedwater Regulating Valve
GL	-	Generic Letter
HELB	-	High Energy Line Break
HIC	-	High Integrity Container
HPCI	-	High Pressure Coolant Injection System
IDNS	-	Illinois Department of Nuclear Safety
IM	-	Instrument Maintenance
IP	-	Interim Procedure
IR	-	Inspection Report
IRM	-	Intermediate Range Monitor
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LLRT	-	Local Leak Rate Test
MSIV	-	Main Steam Isolation Valve
PIF	-	Problem Identification Form
PM	-	Preventative Maintenance
PMT	-	Post Maintenance Testing
RBBP	-	Reactor Building Blowout Panel
RCIC	-	Reactor Core Isolation Cooling System
RHRSW	-	Residual Heat Removal Service Water
RPS	-	Reactor Protection System
RWCU	-	Reactor Water Clean Up
SQV	-	Site Quality Verification
TBV	-	Turbine Bypass Valve
TS	-	Technical Specification
TSUP	-	Technical Specification Upgrade Program
UE	-	Unusual Event
UFSAR	-	Updated Final Safety Analysis Report