U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	ComEd
Facility:	Dresden Nuclear Station Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	November 13 through December 30, 1999
Inspectors:	K. Riemer, Senior Resident Inspector B. Dickson, Resident Inspector D. Roth, Resident Inspector R. Zuffa, Illinois Department of Nuclear Safety
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EXECUTIVE SUMMARY

Dresden Nuclear Station Units 2 and 3
NRC Inspection Report 50-237/99021(DRP); 50-249/99021(DRP)

This report includes the results of routine inspection by the resident inspection staff from November 13 through December 30, 1999.

Operations

- Overall the routine walkdowns showed that problems with plant systems were properly identified and entered into the corrective action system. However, the inspectors identified several minor equipment problems during routine system walkdowns that the licensee personnel had not identified. (Section O2.1)

- The isolation condensers were in the correct standby alignments. The overall materiel condition of the isolation condenser systems was good. (Section O2.2)

- Failure of the main condenser circulating water reversing valve to fully reposition caused a challenge to the operators. Operators responded appropriately to this challenge. (Section O2.3)

- A loose socket on a relay caused an unexpected turbine trip and automatic reactor scram during a surveillance. The licensee's investigation and review of the event were good. (Section O2.4)

- Operators responded to the turbine trip and reactor scram correctly and in accordance with the procedures. (Section O2.4)

- The inspectors concluded that Technical Specification required tests were completed satisfactorily by the licensee. However, the inspectors noted a weakness in licensee performance in regards to properly securing the door latching mechanism on environmentally qualified equipment. The licensee did not capture this issue in the corrective action program until prompted by the inspectors. (Section O3.1)

- Generally operators practiced good communications, followed procedures, and were attentive to the control panels. (Section 04.1)

- The licensee's implementation of the out-of-service program was generally acceptable. However, two issues with inadequate out-of-service implementation occurred. (Section O4.2)

- The on-shift operators were unaware of false control room indication on the drywell post-accident instrument lines, even though the licensee had entered the issue into the corrective actions process several times during the past 3 years. (Section O4.3)

* Corrective actions taken by the Operations Department in response to three issues involving reactor water cleanup system isolation, failure to recognize Technical Specification requirements, and failure to maintain control room operator respirator qualifications were not effective in preventing recurrence of the problems. (Section 07.1)

<u>Maintenance</u>

* Generally maintenance personnel performed adequately. However, the inspectors noted that a licensee identified post-maintenance housekeeping issue was indicative of poor maintenance practices. (Section M1.1)

* A loss of control of foreign material (welder's mask in the condensate system) resulted in an unnecessary challenge to operators. (Section M2.1)

* The motor operated valve engineering group had good cognitive knowledge of the LPCI pump suction valve degradation issue and planned appropriate corrective action. (Section M2.3)

<u>Engineering</u>

* The inspectors found the Corrective Action Program and Nuclear Oversight Program were being properly implemented with respect to tracking and resolution of station issues. (Section E7.1)

<u>Plant Support</u>

* The inspectors assessed the plant radiological controls during routine plant tours and inspections. No concerns were identified by the inspectors. (Section R1.1)

Report Details

Summary of Plant Status

Unit 2 began this inspection period at approximately full power. On November 12, 1999, while Unit 2 was at full power, foreign material in a condensate/condensate pump booster (CCBP) line forced the operators to drop load to 750 MWe. Operators briefly increased power to 775 MWe. A few hours later, material in another CCBP required a reduction back to 750 MWe, then eventually to 233 MWe. During the subsequent load recovery on November 16, a problem with a #4 turbine control valve scram signal forced the licensee to drop power from 600 MWe to about 250 MWe. The licensee repaired the signal and restored the unit to full power by November 19, 1999.

Unit 3 began this inspection period at approximately full power. On December 11, 1999, Unit 3 automatically scrammed during weekly turbine testing due to a problem with the turbine testing circuitry. Full power was restored by December 13, 1999. Unit 3 remained at full power except for planned surveillance and maintenance activities that required load reductions.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. Specific events and noteworthy observations are detailed in the sections below.

During the inspection period, some events occurred that required prompt notification of the Nuclear Regulatory Commission per 10 CFR Part 50.72. The licensee formally notified the NRC of the following events:

11/23/1999	Loss of ENS Phone System
12/11/1999	Unit 3 Reactor Scrammed During Weekly Turbine Surveillance Testing
12/17/1999	Loss of ENS Phone System
12/22/1999	Unit 2 Shutdown Cooling System Inoperable (not in service at time of failure)

O2 Operational Status of Facilities and Equipment

O2.1 Routine System and Plant Walkdowns (Units 2,3)

a. Inspection Scope (71707)

The inspectors reviewed the status and availability of selected equipment through panel monitoring, system walkdowns, and review of logs.

b. Observations and Findings

In general, the systems and components in the facility were maintained adequately. Problems and deficiencies such as oil leaks were identified and entered into the licensee's corrective action process with action request tags.

On December 12, 1999, during a routine walkdown of the Unit 3 diesel generator starting air system, the inspectors noticed that the relief valve (EPN 3-4699-313B) for the B1- DG starting air receiver tank was missing its relief valve lock wire assembly. A subsequent inspection of the three remaining relief valves on the Unit 3 starting air system, and of the eight other relief valves on Unit 2 and Unit 2/3, found no missing lock wires. The licensee documented the problem in PIF # D1999-04960, and initiated Action Request # 990062046 to replace the lock wire.

A search of the electronic work control system revealed that no work had been performed on relief valve 3-4699-313B since 1990. The inspectors contacted the in service testing (IST) engineer. The IST engineer did not know why the lock wire was missing, but stated that the lock wire was not an IST requirement. The lock wire mechanism was attached by the vendor when the valve was supplied to the site, and is replaced if the relief lift setting of the valve is adjusted.

During a routine walkdown of Unit 3 plant equipment on December 21, 1999, the inspectors noticed that the time overcurrent relay trip flag (151) on the main breaker for the 3-1502-B (3B low pressure coolant injection (LPCI)) pump was in the tripped condition. The inspectors notified the work execution center senior reactor operator. The inspectors noted that work was performed on the pump from December 14 to December 16, 1999. The pump and its breaker were returned to service on December 16.

The inspectors identified a similar issue in the prior inspection period (reference IR 99018, PIF # 1999-04582), where the inspectors noted that relay targets on bus 27 for the Unit 2 main turbine were actuated following the return of the bus to service. The relay targets did not represent a safety significant issue, however, they had the potential to hamper troubleshooting efforts if another problem occurred.

The inspectors identified other issues related to plant equipment status that were not noted by operations, engineering, or maintenance staff during routine walkdowns. For example, on December 30, 1999, the inspectors noted that the Unit 3 control rod drive stationary lift by the Unit 3 drywell access had been left unsecured, and could swing into the drywell spray motor operator valve. The licensee documented this item via PIF# D1999-05348.

Other issues identified by the inspectors this period included oil leaks on the 2/3 emergency diesel generator, a door to the Unit 2 emergency diesel generator day tank room that was able to hit one of the diesel air start receiver gauges, several leaking scram inlet valves on control rod drive system hydraulic control units and an erratic pressure gauge on the air-supply line to the 2B reactor feedwater pump min flow valve. The licensee documented the deficiencies via PIF# D1999-05352 and Action Request 990066041 and 990066042.

The inspectors considered these issues to be additional examples of items that had not been identified by operators and other licensee staff during normal system walkdowns.

c. Conclusions

Overall the routine walkdowns showed that problems with plant systems were properly identified and entered into the corrective action system. However, the inspectors identified several issues during routine system walkdowns that licensee personnel had not identified.

O2.2 Engineered Safety Feature System Walkdowns (Units 2,3)

a. Inspection Scope (71707)

During the inspection period, the inspectors used Inspection Procedure 71707 to walk down accessible portions of the Unit 2 and Unit 3 isolation condenser systems.

b. Observations and Findings

The inspectors verified that the equipment was in the correct standby valve and electrical alignments per the appropriate operating procedures. The inspectors checked equipment for signs of degradation from elevated temperatures at the standby operational mode, and also for the environmental integrity of the supporting control instrumentation. No degradation was noted.

c. Conclusions

The isolation condensers were in the correct standby alignments. The overall material condition of the isolation condenser systems was good.

O2.3 System Performance Problems during Circulating Water Flow Reversal

a. Inspection Scope(71707)

The inspectors reviewed operator performance with respect to a material condition issue with the main condenser circulating water reversing system.

b. Observations and Findings

On November 15, 1999, while operations personnel were attempting to reverse circulating water flow through the Unit 2 main condenser, motor operated valves did not move to their required position to facilitate condenser water flow reversal. As a result, circulating water flow decreased and main condenser vacuum decreased one inch. Operations personnel promptly recognized the system perturbation, backed out of the evolution, and restored circulating water flow to original configuration.

c. Conclusions

Failure of the main condenser circulating water reversing valve to fully reposition caused a challenge to the operators. Operators responded appropriately.

O2.4 Reactor Scram Due to Main Turbine Trip (Unit 3)

a. Inspection Scope (71707)

On December 11, 1999, the Unit 3 reactor automatically scrammed from full power due to a trip of the main turbine. The inspectors reviewed operator and equipment performance following the scram, Dresden Operating Surveillance 5600-02 ("Weekly Turbine Checks"), and reviewed the results of the licensee's scram investigation team.

b. Observations and Findings

On December 11, 1999, operators conducted weekly main turbine surveillance checks per Dresden Operating Surveillance 5600-02. During the conduct of the test, the Unit 3 reactor tripped from a main turbine stop valve closure that was initiated by the turbine overspeed test circuit.

After successful completion of earlier portions of the surveillance test associated with the master trip solenoid valve and thrust bearing wear detector, operators commenced performance of the turbine overspeed oil trip check. Per procedure, an operator pushed the "TEST" pushbutton on the oil trip check panel; operators verified that the expected response (annunciator "Turb Overspeed Trip Blocked") was received. The inspectors subsequently independently verified that the annunciator was actuated, indicating that the step had been properly performed in accordance with procedural direction. Operators also verified that the green "NORMAL" light extinguished and the yellow "LOCKED OUT" light illuminated as required by procedure. Receipt of the "LOCKED OUT" light indicated that the mechanical trip valves' ability to cause a turbine trip was blocked. When the operator pushed the oil trip pushbutton to test the oil trip circuit, the turbine stop valves closed and the reactor scrammed.

Operators properly entered and executed the appropriate reactor scram procedures. Operators responded well to the unexpected reactor trip and placed the plant in a stable condition. With the exception of an unexpected high temperature isolation of the reactor water cleanup system (reference Section O7.1 of this report), plant equipment responded as expected.

The licensee formed an event response team to investigate the cause of the main turbine trip and reactor scram. During the post-scram investigation, the licensee identified that the automatic turbine trip was caused by a faulty relay in the oil trip circuitry (reference Section M2.3 of this report). The failure caused an unexpected turbine trip, and, since the reactor was operating at greater than 45 percent power, an automatic reactor scram due to the main turbine stop valves being greater than 10 percent closed. The event response team performed a thorough investigation.

Additional followup of this event will be performed after receipt of the licensee event report.

c. <u>Conclusions</u>

A material condition deficiency (faulty relay)caused an unexpected turbine trip and automatic reactor scram. The licensee's investigation and review of the event were good.

Operators responded to the turbine trip and reactor scram correctly and in accordance with the procedures.

O2.5 <u>Unit 2 Loss Of Shutdown Cooling Function</u>

Operators made an ENS phone notification to the NRC on December 22, 1999, pursuant to 10 CFR 50.72(b)(2)[4-hr Non-Emergency] due to a failure of the Unit 2 logic circuitry in the shutdown cooling system, which would have prevented the system from being placed on line. The reactor recirculation loop resistance temperature detector (RTD) monitors reactor coolant temperature and feeds control room temperature recorder TR-2-260-11. When reactor coolant temperature drops to ~350°F the RTD deactivates an inhibit logic function on the suction isolation valves. This allows the operators to open the valves and proceed into the shutdown cooling mode of operation. The connector between the RTD and the recorder apparently failed, resulting in a high connector-to-recorder resistance, which simulated a high reactor coolant temperature condition. With the recorder failed high, the logic permissive to open the shutdown cooling suction isolation valves would not have occurred. The event was categorized as a loss of residual heat removal capability under

Section (iii)(B) of the event notification worksheet. The shutdown cooling system was not required to be operable in modes 1 & 2 (Run & Startup/Hot Standby). However, the isolation logic is required in modes 1, 2, and 3 (Hot Shutdown).

O3 Operations Procedures and Documentation

O3.1 Technical Specification Required Surveillance Tests

a. Inspection Scope (71707)

The inspectors observed and reviewed the results of several Technical Specification required equipment surveillance tests. The sample of systems reviewed included the following tests:

DOS 1400-05	Unit 3 B Core Spray Operability Surveillance
DOS 1500-01	Unit 2 LPCI System Operability and Valve Timing
DOS 6600-01	Unit 2 Diesel Generator Monthly Operability Surveillance
DOS 6600-03	Unit 3 Diesel Generator Monthly Operability Surveillance
DOS 7500-02	Unit 2/3B Standby Gas Treatment System Monthly Surveillance
DES 0040-32	LPCI and Core Spray Motor EQ Surveillance
DIS 1200-04	RWCU System Area High Temperature Isolation Calibration and Functional Test

As part of the review, the inspectors compared the tests with the Updated Final Safety Analysis Report and the Technical Specifications.

b. Observations and Findings

During the review of the completed tests, the inspectors determined that the periodicity of the surveillance tests met the minimum periodicity requirements as stated in the Technical Specifications. The inspectors also confirmed that the surveillance acceptance criteria, listed in the procedure for each surveillance, met the intent of the Technical Specifications requirements.

On December 22, 1999, during a continuing inspection of environmentally qualified (EQ) components per Dresden Instrument Surveillance (DIS) 1200-04, "RWCU System Area High Temperature Isolation Calibration and Functional Test," the inspectors noted that several door latching mechanisms associated with cabinets 2-2202-77B and 3-2203-77A were loose, whereas Section I.61.k. of DIS 1200-04 required the latches to be "Hand Tight." The latching mechanisms were required to establish and maintain EQ integrity. The inspectors also inspected other cabinets in the Unit 2 and 3 reactor buildings identified as EQ and found the latching mechanisms to be either less than hand tight or, in one instance, missing completely. These cabinets were 2RB -252 (missing latching clip), 3RB -250 (loose latching clips), 3RB -252 (loose latching clips).

The inspectors contacted the cognizant EQ engineer and discussed the status of the EQ cabinet latching mechanisms. The engineer walked down the cabinets, and subsequently the licensee's Fix-It-Now Team tightened or replaced the loose clips as needed.

Follow up discussions with the engineer indicated that this issue was not an equipment operability issue. It was more an issue related to craft personnel workmanship, procedural adherence, and house keeping of plant equipment rather than environmental integrity. This conclusion was based on the fact that the door gasket material was intact and compressed sufficiently. The inspectors agreed with the engineer's assessment.

Another issue noted by the inspectors was that the licensee did not write a PIF documenting this issue in the corrective active process until prompted by the inspectors (PIF D2000-00059), days after the initial identification of this issue.

c. Conclusions

The inspectors concluded that Tech Spec required tests were completed satisfactorily by the licensee. However, the inspectors noted a weakness in licensee performance in regards to properly securing the door latching mechanism on environmentally qualified equipment. The licensee did not capture this issue in the corrective action program until prompted by the inspectors.

O4 Operator Knowledge and Performance

O4.1 Operator Performance

a. Inspection Scope (71707)

The inspectors evaluated operator performance during both planned and emergent plant conditions.

b. Observations and Findings

Performance of the operators was generally good. Operators followed procedures, practiced good communications, and were attentive to the control panels. The inspectors noted that operators usually documented issues and concerns in the corrective actions process via a PIF. Some exceptions were noted by the inspectors as discussed in Sections 04.2, 04.3 and 07.1.

c. Conclusions

Generally, operators followed procedures, practiced good communications, and were attentive to the control panels. Some exceptions were noted by the inspectors.

O4.2 Out- of- Service Program Issues

a. Inspection Scope (71707)

The inspectors reviewed the licensee's implementation of the "Out- of- Service" (OOS) process. The review included routine field observations and monitoring of the licensee's response to problems.

b. Observations and Findings

The licensee's implementation of the out-of-service program was generally acceptable. Direct observation of the restoration of equipment by operations staff revealed no problems. However, during the period, three issues related to the OOS program were identified by the licensee and were documented in PIFs.

First, on November 12, 1999, workers starting to perform maintenance on the reactor building equipment drain tank found the system to be pressurized. The workers identified that the out-of-service was inadequate when the workers first loosened a fitting on the system. The licensee entered the issue into the corrective actions program via PIF# D1999-04736. The licensee found that isolation valves in the system were leaking, some valves failed opposite the usual position, and that the fail positions of the valves were not listed in procedures or prints. Second, on November 15, 1999, electricians found a voltage present while verifying the adequacy of an out-of-service on a control switch for the station blackout diesel generator. The licensee entered the issue into the corrective actions program via PIF# D1999-04765. The licensee found that the out-of-service was prepared incorrectly. Both of these issues appeared to be the result of operations staff incorrectly preparing the out-of-service requests. The licensee assigned an investigation into the issue (AR# AT-19371), but the investigation was not complete at the end of this inspection period.

Both incidences described above occurred on nonsafety- related equipment. The inspectors considered the out-of-service errors to be more examples of the decline in operations performance observed during this period, and originally discussed in Inspection Report 99018. See Sections O7.1 of this report for more discussions of the decline in operations performance.

c. Conclusions

The licensee's implementation of the out-of-service program was generally acceptable. However, two issues with inadequate out-of-services implementation occurred.

O4.3 Operator Knowledge of False Control Room Indication

a. Inspection Scope (71707)

The inspectors reviewed the progress in repairing a false control room indication. During the course of the review, the inspectors assessed the control room operators' knowledge of the issue.

b. Observations and Findings

Background

On November 19, 1999, station engineering personnel wrote PIF # D1999-04819 to document that control room indication for the 2-2599-26A/B and 3-2599-26A/B excess flow check valves was showing closed, with a green closed indicator lit and a red open indicator dark. The valves should be open with a green open indicator lit and a red closed indicator dark.

The 2(3)-2599-26A/B excess flow check valves are installed on containment-penetrating instrument lines for the atmospheric containment atmosphere dilution system, and the same instrument lines provide post-accident containment pressure information to the operators. The excess flow check valves are normally open.

The inspectors found that the licensee had previously discussed the issue in Engineering Request (ER) 9601015, which was initiated on February 16, 1996. The ER was for simulator modeling of the 2(3)-2599-26A(B) position indication for the excess flow check valves.

In 1997, an investigation was performed into the required position of the excess flow check valves. Engineering staff, who reviewed the results, concluded that the investigation in 1997 had only verified that the color of the lights (red and green) matched the prints, but did not resolve the issue of the actual valve status (open or closed). The licensee wrote PIF# D1998-05934 in late 1998 to document the concern, and ER 9803837 was initiated November 16, 1998, to investigate the issue. The ER also stated that "No operability concern exists as instrumentation is capable of sensing pressure even when valve is in checked flow position. Once data is obtained from AR 990003034, action will be taken for proper labeling or repair of valve . . . Work Request 990005094 is scheduled for 11/15/99 to verify wiring of position indication limit switches for these check valves." As discussed at the beginning of this section, the work was completed a year later and on November 19, 1999, station engineering personnel wrote PIF # D1999-04819 to document that the valves were open although the control room showed the valves as closed.

Operator Knowledge of Issue

On December 27, 1999, inspectors, discussing the issue with on-shift reactor operators, found that only one of three interviewed were aware of the issue.

The indications in the control room, which showed the incorrect valve positions, had no deficiency tag to inform the operators of the problem. No entries in the control room abnormality log discussed the issue.

The inspectors and the shift manager discussed the issue, and the unit supervisor documented the inspectors' concern in PIF# D1999-05296 on December 27. However, at the end of the inspection period, the PIF had not been signed by the shift manager; the licensee was tracking the PIF on its list of overdue unsigned PIFs. Since the PIF was unsigned and unreviewed by the Events Screening Committee, the inspectors could not assess the total corrective actions.

The immediate corrective actions were to add entries to the control room abnormality logs, and to place standard work request stickers on the control room indications, thereby informing all operators that the control room indications were false. The inspectors concluded that the immediate corrective actions were appropriate.

More information is required to determine whether the issues regarding the false control room indication are acceptable items, deviations, nonconformances, or violations. Therefore, the NRC considers this to be an **Unresolved Item (URI 50-237;99021-01)** pending NRC review of the entry and resolution of this issue in the corrective action program.

c. <u>Conclusions</u>

The on-shift operators were unaware of false control room indication on the drywell post-accident instrument lines, even though the licensee had entered the issue into the corrective actions process several times during the past 3 years.

O7 Quality Assurance In Operations

O7.1 <u>Recurrence of Previous Problems</u>

a. <u>Inspection Scope (71707)</u>

The inspectors reviewed the circumstances surrounding three deficiencies that were similar to previous problems at the site.

b. <u>Observations and Findings</u>

The inspectors reviewed three issues, one self-revealing and the others licensee identified, that occurred during the inspection period. The issues were a high temperature isolation of the reactor water cleanup system following a reactor scram, operator non-recognition of Technical Specification limiting condition for operation entry conditions, and the Operations Department's effectiveness at maintaining respirator qualifications for required personnel. All of the items were similar to past issues at the site.

Reactor Water Cleanup System Isolation due to High Temperature: The reactor water cleanup system isolated on high temperature following the reactor scram on December 11, 1999. The system initially isolated, as expected, upon a low reactor water level, which occurred as a result of the reactor scram. Operators subsequently restarted the system to assist with reactor water level control. The normal method of level control included adding water with a reactor feed pump and removing water via the reactor water cleanup system. A short time later the system isolated again; the second system isolation was due to a high demineralizer inlet temperature. The system isolation impacted the operators' normal method of reactor water level control. Operators controlled reactor water level by securing a reactor feed pump and using a smaller capacity control rod drive pump. Steam loads in the balance of plant accounted for the removal of inventory from the reactor vessel.

The high temperature isolation of the Unit 3 reactor water cleanup system following the reactor scram was similar to the plant response on Unit 2 several months earlier. Operators inserted a planned manual scram to complete the reactor plant shutdown to support the Unit 2 refueling outage in October 1999. Subsequent to the insertion of the manual scram, the Unit 2 reactor water cleanup system isolated due to a high temperature condition. The licensee determined that due to an earlier flow balancing of the reactor building closed cooling water (RBCCW) system (heat sink for the reactor water cleanup system non-regenerative heat exchanger), RBCCW flow through the reactor water cleanup system heat exchanger was reduced. Consequently, a high reactor water blowdown flow rate through the reactor water cleanup system heat exchanger could not be adequately cooled, and a system high temperature isolation occurred. Station engineers verified that this was an expected response for the system conditions, and operators modified their procedural instructions on Unit 2 to limit the blowdown flow to preclude a high temperature isolation of the reactor water cleanup system. The station had also performed a flow balancing of the Unit 3 RBCCW system during the Unit 3 spring of 1999 refueling outage. Station personnel verified that the Unit 3 reactor water cleanup system high temperature isolation following the December 11, 1999, reactor scram was the proper system response for the Unit 3 system conditions.

The inspectors were concerned that the Operations Department missed an opportunity to prevent the unwanted system isolation and associated operator challenge on Unit 3.

Failure to Recognize Limiting Condition for Operation Entry Conditions: On December 21 1999, operators declared both divisions of the Unit 2 low pressure coolant injection system inoperable based upon receipt of the system discharge header pressure low alarm. Operators received the alarm while returning the system to service following routine, scheduled maintenance. However, operators failed to recognize two additional Technical Specification limiting condition for operation conditions. Upon declaring the low pressure coolant injection system inoperable, operators should also have entered the Technical Specification for suppression chamber and drywell spray and the Technical Specification for suppression pool cooling. This event was a repeat of an issue documented in an earlier NRC inspection report (reference Inspection Report 98-021). Operators did not implement the corrective actions from the prior occurrence to prevent repetition of the event.

The following operating shift determined that the initial system inoperability call was unnecessary since the discharge pressure remained positive at all times, and the surveillance procedure, being run at the time, provided guidance to allow a four-hour window for system filling and venting, if necessary, to clear the low pressure condition. The station entered the unnecessary inoperability declaration into the corrective action process via PIF D1999-05253. The inspectors did not disagree with this evaluation. However, the inspectors were concerned that when the original system operability decision was made, not all associated Technical Specification requirements were recognized or acted upon. The inspectors were also concerned that the operator non-recognition of the Technical Specifications requirements was not formally entered into the station's corrective action process by generation of a PIF. The original corrective actions were not effective at preventing recurrence of the original issue, nor was the second occurrence entered in the licensee's corrective action process.

Respirator Qualifications for Required Operations Personnel: The licensee identified that a significant number of control room operators had not maintained their required respirator qualifications. The radiation protection department identified the issue during a fourth quarter self assessment and documented the finding via PIF D1999-05174. The identification of the concern raised a habitability issue in the event that respiratory protection would be required to be used in the control room. The Operations Department did not effectively incorporate lessons learned from a similar utility-generated notification following a similar event at another licensee plant.

c. Conclusions

Corrective actions taken by the Operations Department in response to three issues involving reactor water cleanup system isolation, failure to recognize Technical Specification requirements, and failure to maintain control room operator respirator qualifications, were not effective in preventing recurrence of the problems.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-237/97019: Spurious Local Power Range Monitor Spike Results in Full Reactor Scram Caused by Design/Manufacturing Deficiency and Management Deficiency. The inspectors verified that the licensee completed corrective actions including performing current/voltage tests on the local power range monitors to detect degradation and expediting the scheduled replacement of the local power range monitors with improved detectors. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Maintenance

a. Inspection Scope (62707, 61726)

The inspectors reviewed project work scope, work procedural requirements, job specific work requirements and other pertinent information necessary to perform outage maintenance evolutions. The inspectors also discussed in-progress work, on location, with cognizant field supervision.

b. Observations and Findings

The inspectors observed the work at several job locations throughout the plant. Work packages were at, or near, the work stations and were being properly used. The procedures were being followed. The job supervisor was normally present at the job site directing activities. The inspectors observed the performance of several job specific activities. Safety precautions were normally followed, and both workers and the supervisor were knowledgeable in the activity and answered any questions the inspector had about the work in progress. The following major work activities were observed by the inspector:

2/3 Emergency Diesel Fire Pump - Annual Maintenance per WR 990081494 3B
Condensate Booster Pump - Clean/Insp/Bridge/Megger per WR 9900561512D
LPCI pump Motor 2 year EQ Surveillance per WR 980017153 A
Inst Air Compressor - Clean/Inspect per WR 990012691.

For the majority of the work performed, projects were completed on time and with minimal rework. Work areas were generally maintained free of debris and clutter, and with the exception of the 2D LPCI Pump-Motor area, most work areas were returned to a state of pre-job cleanliness. The 2D LPCI Pump-Motor work area was left with material condition issues, which prompted Operations not to accept the equipment from the Maintenance Department until these conditions were resolved. This condition was identified within the Operator's Daily Logs as well as through the PIF System.

c. Conclusions

Generally maintenance personnel performed adequately. However, the inspectors noted that a licensee identified post-maintenance housekeeping issue was indicative of poor maintenance practices.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Foreign Material in Condensate Booster Pump (62707)

a. Inspection Scope (62707)

The inspectors monitored the licensee investigation into problems with the 2D and 2C condensate/condensate booster pumps.

b. Observations and Findings

On November 12, 1999, while Unit 2 was at full power, the condensate pump discharge pressure and condensate pump suction pressure low alarms sounded and the standby condensate/condensate booster pump (CCBP) automatically started. Operations staff lowered reactor power from 842 MWe to 750 MWe in preparation for securing a CCBP. The non-licensed operator reported that the 2C CCBP sounded abnormal, so operators secured it. Subsequently, operators commenced a power increase to 775 MWe, then held a conference on the issue. A few hours later, while the reactor was still about 775 MWe, a non-licensed operator reported that another CCBP, this time the 2D CCBP, sounded abnormal. Operators then reduced load back to 750 MWe. Engineering staff evaluated the 2D CCBP's vibrations and thermal performance, and found the pump to be normal (except for the sound). A few hours later, the operators started to lower reactor power to 450 MWe.

During the power decrease, at about 670 MWe, a Channel A reactor scram signal (also called a ½ scram) occurred. No abnormal parameters were found, and the Channel A scram signal was reset. The Channel A scram signal promptly recurred. Again, all parameters were normal, and the operators reset the signal and continued the downpower. A few minutes later, the signal recurred, and a few minutes after that another annunciator allowed the operators to identify the source of the ½ scram as a failed or chattering relay for the turbine control valve #4 load reject signal. The operators pulled the fuse for the signal and complied with the appropriate Technical Specifications, then continued with the downpower to 233 MWe. This issue is discussed more in Section M2.2.

Subsequent investigations and disassembly of the 2C CCBP and the 2D CCBP revealed several pieces of a plastic welder's face shield in the pump casing. The licensee believed that this material came from the condenser hotwell area as a result of the D2R16 outage work being performed in that area. The issue was entered into the corrective actions program in PIF# D1999-04744 and other PIFs.

c. Conclusions

A loss of control of foreign material (welder's mask in the condensate system) resulted in an unnecessary challenge to operators.

M2.2 Spurious ½ Scrams from Relay Chatter on #4 Control Valve

The licensee experienced problems with spurious reactor protection system trips from the #4 Control Valve on November 13, 1999, as discussed above. The licensee then replaced a microswitch internal to the #4 control valve pressure switch.

By November 16, the licensee had completed repairs on the 2C and 2D CCBP, and was raising power. At about 600 MWe, the same ½ scram signal occurred. The licensee dropped load to below 45 percent to remove the control valve scram signals from the reactor protection system. The license eventually dropped load to about 250 MWe and replaced the entire pressure switch.

The licensee was unable to determine why the switch failed originally because the failed micro switch relay was not assessed before being replaced. The licensee reviewed the first effort at replacement on November 13 with the micro switch vendor, and concluded that relevant vendor information for replacing the micro switch was not known to the licensee. The second replacement was successful because the entire relay, not just the micro switch, was replaced.

M2.3 Potential Valve Internals Wearing of LPCI Pump Suction Isolation Valves

a. Inspection Scope (71707)

On December 12, 1999, operators performed valve timing of the 2-1501-5D (2D LPCI Pump Suction Isolation Valve). The valve's closing time was excessively long (>241 seconds). The licensee declared the valve inoperable and entered Dresden Technical Specification 3.5.A.2 "Emergency Core Cooling System-Operating." The inspectors reviewed the troubleshooting efforts, and the findings resulting from those efforts with the motor operated valve engineering staff.

b. Observations and Findings

The motor operated valve engineering group concluded that the valve's horizontal orientation within the physical configuration of the system induced internal valve gate to valve guide frictional stresses that had increased incrementally with valve age. The horizontal configuration of the valve caused the valve's gate to be dragged along the surface of the valve guide, gradually pitting and eroding the guide surface to the point where additional torque was required from the valve's primary drive (motor operator) to close the valve. The engineering organization planned to replace the valve's internal components with higher strength valve guide materials that have greater resistance to frictional stress wearing. The licensee was developing plans to upgrade the valve's internal components.

c. Conclusions

The motor operator valve engineering group had good cognitive knowledge of the LPCI pump suction valve degradation issue and planned appropriate corrective action.

M2.4 Turbine Trip and Reactor Scram During Surveillance Testing

Trouble shooting was performed by the licensee's Instrument Maintenance Department immediately following stabilization and controlled cool down of the Unit 3 reactor following the scram on December 1, 1999. Testing of the electrohydraulic control logic circuitry revealed a loose socket connection between signal relay (XK3) and the lockout valve solenoid. Additional testing indicated that the XK3 relay was initially able to energize the lockout solenoid and re-position the lockout valve to the trip prohibit position. However, due to the loose socket connection, the voltage required to maintain the solenoid in the energized position diminished to the point where the solenoid de-energized, allowing the lockout valve to revert to its "Trip Enable" position. This action promptly initiated a turbine trip followed by a reactor trip.

Logic diagrams indicated that the component (XK3 relay and socket) was a single failure by design and did not have collateral redundancy to prevent system actuation due to its failure. The licensee's engineering personnel had committed to, and were in the process of a definitive system walkdown of the electrohydraulic control system specifically looking for areas vulnerable to failure within the system, at or near the time of this event. They had not yet progressed to the XK3 portion of the electrohydraulic control logic at the time of this event.

The inspectors will complete a formal review of the event following receipt of the licensee event report.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Electro Hydraulic Control Team

The licensee assembled a team to address maintenance of the electro hydraulic control system. The inspectors attended one of the team working meetings and the inspector reviewed the team's charter and plans. Team discussions were open and productive. Areas reviewed included procedures, including how the procedures compared to procedures from other utilities. The inspectors concluded that the team was taking steps to improve maintenance on the electro hydraulic control system.

E7 Quality Assurance In Engineering Activities

E7.1 Routine Assessment of Engineering

a. Inspection Scope (40500)

The inspectors reviewed the licensee Corrective Action Program. The administrative procedure for the Corrective Action Program was reviewed, PIFs that were generated during the inspection period were reviewed, and the inspectors attended several Event Screening Meetings. A cross section of PIFs were reviewed for content and quality along with the corrective actions assigned to those PIFs to resolve the identified issue.

The inspectors also monitored the licensee's Nuclear Oversight Program with respect to the organization's aggressiveness to review and identify programmatic deficiencies at all levels of the station activities.

b. Observations and Findings

The inspectors monitored the licensee's self-assessments and assessments by the Nuclear Oversight organization. Nuclear Oversight personnel, while following-up on a question from the site's Nuclear Safety Review Board, identified potential issues with a 50.59 evaluation on using the control rod drive cross tie function. The licensee assigned a root cause report on the safety evaluation process (AR# 19457 due January 14, 2000). The inspectors noted other issues in the licensee's corrective action process that demonstrated that Nuclear Oversight personnel were performing challenging reviews of 50.59s (see PIF# D1999-04724).

c. Conclusions

The inspectors found the Corrective Action Program and Nuclear Oversight Program were being properly implemented with respect to tracking and resolution of station issues.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Routine Activities

The inspectors assessed the plant radiological controls during routine plant tours and inspections. The inspectors noted that the licensee placed an increased emphasis on dose reduction through planning and accountability. Also, the inspectors noted that the licensee substantially decreased the allowable maximum radiation dose rate alarms for general work in the radiologically controlled area. No concerns with the radiological controls were identified by the inspectors.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on December 30, 1999, following the conclusion of the inspection period. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The licensee identified no proprietary information.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Ambler, Regulatory Assurance Manager
R. Fisher, Operations Manager
M. Heffly, Site VP
R. Kelly, NRC Coordinator
P. Planning, Unit 1 Manager - Safestor Project Director
R. Sperhoff, FIN Team Manager
J. Stone, Nuclear Oversight Manager
P. Swafford, Station Manager

NRC

B. Dixon, Dresden Resident Inspector
K. Riemer, Dresden Senior Resident Inspector
D. Roth, Dresden Resident Inspector

IDNS

R. Zuffa, Illinois Department of Nuclear Safety

INSPECTION PROCEDURES USED

IP 40500:	Effectiveness of Licensee Corrective Action Process
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-237;99021-01	URI	Operator Recognition of False Control Room Indication

<u>Closed</u>

50-237/97019	LER	Spurious Local Power Range Spike Results in Reactor Scram

<u>Discussed</u>

None

LIST OF ACRONYMS USED

CCBP	Condensate/Condensate Booster Pump
DIS	Dresden Instrument Surveillance
EQ	Environmentally Qualified
ER	Engineering Request
IST	In Service Testing
LER	Licensee Event Report
LPCI	Low Pressure Cooling Injection
psig	Pounds Per Square Inch Gage
OOS	Out of Service
RBCCW	Reactor Building Closed Cooling Water
RTD	Resistance Temperature Detector
URI	Unresolved Item