ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
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Attachment:	Supplemental Information

EXECUTIVE SUMMARY

Cooper Nuclear Station
NRC Inspection Report 50-298/97-05

Operations

- The licensee stopped some outage work after scheduling and implementation difficulties in the electrical and I&C areas caused several unexpected occurrences. The licensee re-enforced expectations and took actions to address the immediate problems with control of outage activities. The actions were effective in improving work scheduling and control (Section O1.1).

- Inspectors noted an improvement in operations shift turnover briefings. The briefings showed an emphasis on safety and risk and an involvement by licensed and unlicensed operators (Section O1.3).

- The licensee did not have detailed, clear, or consistent design information from which to evaluate the operability of the control rod drive housing support (Section O2.1).

- The inspectors walked down the drywell and torus and found that primary containment cleanliness was good and the licensee close-out process appeared effective. The torus water was clear with no foreign material observed in the water (Section O2.3).

- Inspectors identified that operations had not properly implemented expectations for operators to control equipment conditions during testing which was run by engineers. Apparent indication discrepancies were informally addressed and the test coordinator did not halt testing when unexpected indications were encountered (Section M2.1).

- For a surveillance test which did not adequately document the verification of interlock operation, inspectors identified that the operability assessment did not provide an adequate basis for operability. NRC involvement was required to establish a basis for operability (Section O2.2).

- The licensee documented instances where clearance orders did not properly prepare systems for maintenance. Interim corrective actions appeared to have addressed and precluded these occurrences (Section O7.1).

Maintenance

- Inspectors noted a significant increase in the quality and quantity of problem identification reports prepared by the maintenance department (Section M7.1).

- Inspectors observed that maintenance technicians were not signing all steps of a high pressure coolant injection overspeed test as the work order was performed. This did not meet licensee expectations (Section M2.2).

Engineering

- Inspectors identified that the licensee failed to identify and characterize packed mud buildup in the Residual Heat Removal Heat Exchanger B tubes, although the inspectors informed several key licensee individuals on multiple occasions immediately after identifying that maintenance personnel failed to characterize the extent of the condition. The licensee failed to test heat exchanger performance in accordance with commitments. The operability assessment also required NRC intervention (Section E1.1).

- Inspectors identified that reactor engineers and the reactor engineering supervisor had not implemented expectations for reactor engineer duties during fuel movement (Section E1.2).

- The licensee identified that the operational conditions inherent in the core reload analysis were not properly implemented into various plant operations procedures (i.e, procedures allowed operation with reduced feedwater heating, inoperable safety relief valves, nonconservative thermal limits during single loop operation, and other concerns). Inspectors verified that interim corrective actions addressed these issues prior to plant startup (Section E2.2).

Plant Support

- Inspectors identified that unexpected low level contaminations of operators had not been identified to preclude future contamination events. After discussions with health physics, several more occurrences were documented by health physics staff (Section R7.1).

Report Details

Summary of Plant Status

The plant was shut down in Refueling Outage 17 for the entire reporting period.

I. Operations

O1 Conduct of Operations

O1.1 Licensee Stop Work After Problems Were Encountered During the Outage

a. Inspection Scope (71707)

The inspectors observed licensee response to problems encountered during the outage.

b. Observations and Findings

On May 7, 1997, after an unanticipated reactor scram and group isolation, a failure to maintain secondary containment administrative controls and an unanticipated diesel generator start, the licensee concluded that work should be stopped to emphasize control of outage activities. Licensee management communicated its expectations to the operations, maintenance, and scheduling organizations concerning how to properly control the scheduling and performance of outage activities.

The licensee developed scheduling tools which indicated where key system operability was required and major schedule transitions occurred. Although this information had been available in the prior scheduling process, the information was often difficult to discern. Since the difficulties appeared to be associated with electrical and instrumentation and control (I&C) work, all safety-related I&C and electrical work was halted. Mechanical and nonsafety work was allowed to continue.

Outage work was resumed after corrective actions and new scheduling tools were implemented by the licensee. No similar problems recurred.

c. Conclusions

The licensee stopped some outage work after scheduling and implementation difficulties in the electrical and I&C areas caused several unexpected occurrences. Licensee management re-enforced expectations and took actions to address the immediate problems with control of outage activities. The actions were effective in improving work scheduling and control.

O1.2 Management Involvement in Safety Expectations

a. Inspection Scope (71707)

Inspectors observed plan of the day meetings and other scheduled meetings, and the participation by licensee management.

b. Observations and Findings

On a daily basis, the licensee articulated expectations to staff during scheduled meetings. The licensee emphasized thoughtful use of procedures, understanding expected equipment response, and identification of problems. During one meeting, it was emphasized that the line organization was responsible for proper response to and characterization of plant problems rather than reliance on the Condition Review Group to assign and direct problem resolution. The expectation for ownership of problems and their resolution was clearly articulated.

c. Conclusions

The licensee actively and frequently re-enforced safety and performance expectations during scheduled plant meetings.

O1.3 Improvement in Control Room Briefings

a. Inspection Scope (71707)

The inspectors observed daily shift turnover briefings and briefings for specific activities in the control room.

b. Observations and Findings

Inspectors found that the control room shift turnover briefings emphasized:

- focus on safety and on identification of highest priority plant safety concerns;
- discussion of the four site alignment issues (procedure adherence, safety, good communications, and self checking);
- involvement by licensed and unlicensed operators in the assessment of overall plant conditions;
- examples of appropriate decision making and ownership of plant safety and responsibility, such as slowing the pace of control room work during high activity periods to maintain good control of plant conditions; and,

- discussion by operators during briefings of outage risk with respect to plant conditions.

Discussions with operators showed that the plant manager had provided clear expectations and direct feedback to operations crews concerning their safety responsibility. These expectations regarding safety focus and crew responsibilities had been adopted by each shift crew. Inspectors observed the implementation of these expectations during briefings as well as control of plant activities.

c. Conclusions

An improvement in the conduct and content of control room briefings was noted.

O2 Operational Status of Facilities and Equipment

O2.1 Control Rod Drive (CRD) Housing Supports

a. Inspection Scope (71707)

The inspectors reviewed the following documents to assess the adequacy of licensee's efforts to determine the operability of the CRD housing support structure:

- Updated Safety Analysis Report (USAR), Section III, Chapter 8.0, "Control Rod Drive Housing Supports;"
- Technical Specification (TS) Bases 3.3.B.2;
- Engineering Evaluation EE97-129, "Evaluation of Requirements for Gap Between CRD Housing and CRD Housing Support," dated May 3, 1997;
- Engineering Evaluation EE97-141, "Engineering Evaluation of CRD Housing Dimensional Discrepancies Identified in Problem Identification Report (PIR)#2-01307," dated May 10, 1997;
- Procedure 6.CRD.401, "Control Rod Drive Housing Support Inspection, Revision 0 c1; and
- General Electric Drawing 729E969, Revision 1, "Installation Diagram."

b. Observations and Findings

The CRD housing support is a structure located below the reactor vessel. The USAR, Section III-8.2, states that the design bases of the CRD housing supports are:

- Limit control rod downward motion, following a postulated CRD housing failure, so that any resulting nuclear transient would not be sufficient to cause fuel damage; and,

- Provide sufficient clearance between the CRD housings and the supports to prevent vertical contact stresses caused by thermal expansion during plant operation.

On April 24, 1997, the inspectors performed a walkdown of the CRD housing support to verify proper installation. The inspectors spot checked that the gap between the support housing and the lower surface of the CRD mechanism was within procedural acceptance criteria ($\geq$ 0.75 and $\leq$ 1.25 inches). The inspectors did not identify any problems with the gaps but did note a fastener with a missing washer. The licensee stated that safety significance was minimal since washers were not indicated on installation Drawing GE 729E969, Revision 1. The inspectors then questioned the apparent discrepancy between the drawing, which did not indicate washers, and the actual configuration where washers were installed. The licensee initiated a PIR to document the discrepancy and indicated that they would evaluate the function of the washers and resolve the discrepancy between the drawing and the actual configuration. The licensee maintained that the housing support remained operable. The resolution of these questions will be followed with the unresolved item described below.

The USAR, Section III-8.3, "Description," states that, at room temperature, a gap of approximately 1 inch exists between the grid and the bottom contact surface of the CRD flange. Section III-8.4, "Safety Evaluation," states that downward travel of the CRD housing and its control rod following the postulated housing failure consists of the sum of the compression of the disc springs under dynamic loading and the initial gap between the grid and the bottom contact surface of the CRD flange. Section III-8.4 further states, "if the reactor were cold and pressurized, the downward motion of the control rod would be limited to the spring compression (approximately 2 inches) plus a gap of approximately 1 inch. If the reactor were hot and pressurized, the gap would be approximately 1/4 inch and the spring compression would be slightly less than in the cold condition. In either case, the control rod movement following a housing failure is substantially limited below one drive 'notch' movement (6 inches). Sudden withdrawal of any control rod through a distance of one drive notch at any position in the core does not produce a transient sufficient to damage any radioactive material barrier." The TS 3.3.B.2 Bases specify that the CRD housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. Based on the limit of 3 inches of CRD housing movement specified in the USAR and the TS bases, the inspectors questioned the use of a gap up to and including 1.25 inches, since a housing failure in the cold condition may result in control rod movement of 3.25 inches (2-inch spring compression plus 1.25-inch movement to close the gap.)

As noted above, the design bases stated in USAR, Section III-8.2, also requires sufficient clearance between the CRD housings and the supports to prevent vertical contact stresses caused by thermal expansion during plant operation. The USAR, Section III-8.3, states that a gap of approximately 1 inch is provided at room temperature, and in the hot operating condition a gap of approximately 0.25-inch remains. The USAR, therefore, implied a thermal expansion of the CRD housing equal to 0.75 inches. The inspectors questioned the acceptability of acceptance criteria permitting a gap of greater than or equal to 0.75 inches, since in that case thermal growth could result in contact between the CRD housing flange and the support bar.

In response to the inspectors' questions, engineers developed Calculations EE97-129 and EE97-141. The calculations concluded:

- A thermal growth of 0.249 inches occurs from cold conditions to normal operating conditions, providing a minimum gap of 0.501 inches (0.75 inches minus 0.249 inches);

- A thermal growth of 0.329 inches occurs from cold conditions to design basis loss-of-coolant accident conditions, providing a minimum gap of 0.421 inches (0.75 inches minus 0.329 inches);

- Estimated spring compression resulting from static and dynamic forces of a CRD housing failure would equal 1.644 inches, resulting in total downward control rod movement of less than 3 inches (1.25-inch gap plus 1.644-inch spring compression = 2.894 inches total movement).

The licensee concluded that the calculations formed the basis for reasonable assurance of CRD housing support operability. The inspectors noted that:

- The licensee did not possess the original design analysis for the CRD housing supports, and could not obtain it from the vendor;

- The licensee did not provide the basis for some of the design input numbers used in the calculations; and

- Several values stated in the USAR were different from those calculated and no evaluation in accordance with 10 CFR 50.59 had been performed.

- Prior to plant restart, the licensee planned to provide a basis for the design input numbers used in the operability determination. In addition, the licensee planned to evaluate any changes to CRD housing support design information. NRC review of the basis for design information, the operability and safety evaluations, any proposed USAR update, and the accuracy of Drawing GE 729E969 will be an unresolved item (URI) (50-298/9705-01).

c. Conclusions

Inspectors concluded that the licensee did not have detailed, clear, or consistent design information from which to evaluate the operability of the support housing.

O2.2 Weak Operability Assessment

a. Inspection Scope (71707)

The inspectors reviewed and discussed the operability assessment and associated testing procedures documented in PIR 2-11319 with a shift supervisor and the operations supervisor.

b. Observations and Findings

On April 15, 1997, the inspectors identified a concern with Procedure 6.1SWBP.101 and 6.2SWBP.101, "RHR Service Water Booster Pump Flow Test and Valve Operability Test," Revision 2 c2 and 2 c1, which tested contacts for the "service water booster pump running interlocks" to the Residual Heat Removal (RHR) Heat Exchanger Service Water Outlet Valves SW-MO-89A(B). The procedure required only that operators "ensure" that the valves closed. By the licensee's definition, the word "ensure" allows the operator to manually position equipment (close the valve) without recording a discrepancy. Therefore, it is possible the interlock would not work and would not be recorded as a discrepancy.

The licensee issued PIR 2-11319. The associated operability assessment indicated the following: If the valves did fail to close, the condition would be annunciated by alarms in the control room. This annunciation would alert the operator to the fact that the valves did not fully close. The function of the relays is to close the corresponding valve and this closure is verified by the absence of alarms. Therefore, the safety function of the relays is verified without surveillance testing. The valves and system remain operable.

The inspectors raised the concern that the operability assessment did not provide enough information to conclude that the system was operable. The safety function of the relays is to automatically close the valves when the associated pump is not running. The surveillance procedure already required the operators to manually close the valves if the valves did not automatically close. Furthermore, the inspectors' discussion with operators revealed that, by design, the alarms are received during the surveillance and the alarms clear when the valves are closed (either automatically or with operator action). Operators are not required to document these alarms received during these surveillances. Inspectors also have observed occasions where unexpected alarms received during surveillances were not recorded. Also, the alarms are nonessential equipment, which the licensee would be relying on to verify that essential equipment is operable. Further, the alarm circuit could be subject to a common mode failure of the interlock sensors.

The inspectors held discussions with the operations supervisor who stated that the operability assessment was valid and did not need to be rewritten or information added. Also, the operations supervisor stated that he had talked with the operator who performed both Division I and II surveillances and was told that the valves automatically closed. No documentation of this information was provided to complete the operability assessment.

The inspectors concluded that there was no safety concern based on the operator stating that both valves automatically closed during the surveillance test. This information was not made available nor had it been documented until the inspectors questioned the operability assessment. The quality of this operability evaluation will be reviewed in a future inspection (as part of an inspection for a management meeting) and will be tracked as an inspector followup item (IFI) (50-298/97005-02).

c. Conclusions

Inspectors identified a surveillance test which did not adequately document verification of essential interlock operation. The inspectors identified that the subsequent operability assessment did not provide an adequate basis for essential interlock operability. NRC involvement was required to obtain later interviews with operators to establish a basis for operability and resolve the immediate safety concern.

O2.3 Torus and Drywell Close-Out Inspection

a. Inspection Scope (71707)

The inspectors performed end-of-outage torus and drywell close-out walkdowns.

b. Observations and Findings

On May 9, inspectors performed a walkdown of the torus area to evaluate torus cleanliness. The inspectors found the condition of the torus was generally good and noted a few pieces of tape, which were immediately removed. The inspectors also noted the torus water was clear and no foreign materials were observed above or below the surface of the water. Generally the torus was clean.

On May 15, inspectors performed a walkdown of the drywell after maintenance activities had closed the drywell. Operations, radiation protection, and engineering had yet to perform walkdowns. The drywell was inspected from the reactor flange level to the downcomers. Approximately 3 feet of 2 inch wide personnel safety plastic tape was noted, which had not been removed from drywell camera support installation. The licensee removed the tape and noted that further close-out activities would be occurring by licensee organization. The inspectors noted that,

given the interim status of the drywell close out and the small amount of foreign materials, the licensee appeared to have properly emphasized drywell cleanliness to staff performing closeout.

The inspectors noted temporary lighting cords in the drywell which the licensee stated would be removed during the final drywell closeout process. The inspectors also noted that downcomer foreign material exclusion covers were still in place. The licensee noted that removal of these covers was the primary task of the closeout activities scheduled immediately after the inspectors walkdown.

c. Conclusions

Both the drywell and the torus appeared to have been properly closed out.

O3 Operations Procedures and Documentation

O3.1 Service Water Supply to Reactor Equipment Cooling (REC) Critical Loops

a. Inspection Scope (71707)

Inspectors reviewed the operational procedures and bases for the essential service water supply to the REC critical loop piping. This supply is required in the event of a design basis passive failure of the REC subsystems.

b. Observations and Findings

Inspectors noted that REC critical loops which provided local cooling to critical equipment were not independent. The pump suction return lines were collected in a common header feeding both subsystems of REC pumps and REC heat exchangers were cross connected under emergency conditions. No automatic isolation occurs to separate the two trains of pumps and heat exchangers. The USAR, Section X-6.0, "Reactor Equipment Cooling System," description of the REC system indicated the trains were independent and backed up by a redundant, independent essential service water. A PIR 2-13603, dated March 24, 1997) was initiated to address the need to clarify the USAR description of "independent."

Inspectors found that, for cases where REC pumps or both REC heat exchangers could be affected due to a common mode failure, the USAR indicated use of essential service water to the independent critical loops for design basis accident. In this case, safe shutdown heat loads would be expected rather than loss-of-coolant accident loads. Inspectors examined the expected flows and pressures of the service water system in this system line up and noted that, although a procedure was in place to implement service water cooling, this configuration had never been tested. Inspectors also noted no calculation was available to substantiate system performance in this event.

The licensee performed a calculation which concluded the system was operable.

c. Conclusions

The inspectors identified that the essential service water function to supply reactor cooling critical loops did not have a calculation or surveillance test validating its function. The licensee performed a calculation, which concluded the flow rates could be established.

O3.2 Reactor Pressure Test Surveillance

a. Inspection Scope (71707)

The inspectors reviewed and discussed Procedure 6.MISC.502, "ASME Class 1 System Leakage Test," Revision 1 c1 with the station technical engineer, shift supervisor, and the operations supervisor.

b. Observations and Findings

On May 12, 1997, inspectors reviewed Procedure 6.MISC.502. This procedure directs that shutdown cooling be secured during the reactor pressurization. Step 2.3, states that, with the potential for plant heatup due to a recent shutdown, systems required for operation at greater than 212°F shall be operable.

The inspectors questioned if primary containment was required to be operable during the pressure test. TS require primary containment integrity when reactor water temperature is above 212°F and fuel is in the reactor. On May 11-12, during implementation of this procedure, primary containment was functional but not operable. Reactor water temperature did not exceed 212°F.

The licensee stated that there was no regulatory requirement for primary containment to be operable for the actual conduct of the pressure test. The "intent" of the procedure had been met since Step 2.3 was intended to address situations when decay heat in the reactor was high and introduced the potential to exceed 212°F.

The inspectors noted that the operators did not follow the "shall" statement of the procedure since primary containment was not actually operable during the pressure test. The operations supervisor stated he would review the procedure and make any necessary changes if required.

c. Conclusions

The inspectors identified an example where operations did not comply with a procedural requirement or change the procedure when they determined that the literal requirement was not the "intent" of the procedure. Although no regulatory

requirement appeared to have been violated, this example illustrated that operators followed the perceived "intent" of the procedure contrary to what the procedure statement required.

O7 Quality Assurance in Operations

O7.1 Identification of Operations Clearance Order Problems by Maintenance

a. Inspection Scope (71707)

Inspectors assessed the PIRs which were initiated addressing clearance orders.

b. Observations and Findings

During the outage, PIRs were initiated describing instances where clearance orders had not properly drained and/or depressurized systems in anticipation of maintenance work. Inspectors noted that maintenance personnel had initiated these PIRs. Resolution of these PIRs was assigned to the operations staff and the immediate corrective action taken appeared to have significantly decreased the frequency of these occurrences. Based on interviews, inspectors found that, for prior outages, maintenance had not documented these types of problems on PIRs but instead had resolved individual concerns with operations.

c. Conclusions

Inspectors concluded that these PIRs represented an increase in the use by maintenance personnel of the PIR process. Interim corrective action appeared to have properly addressed and precluded instances of pressurized and/or filled systems which had been released for maintenance work.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

Procedure	Title
2.2.20.2	Operation of Diesel Generator from Diesel Generator Room
6.SC.501	Secondary Containment Leak Test
6.CRD.401	Control Rod Drive Housing Support Inspection
6.MISC.502	ASME Class I System Leakage Test

6.ADS.302	Automatic Depressurization System Accumulator Functional Test
7.2.28.1	High Pressure Coolant Injection Overspeed Trip Inspection and Maintenance
7.2.42	Heat exchanger Cleaning
10.25.2	Refueling - Core Shuffle
MWR 96-2200	Scram Valve Operator Diaphragms Replacement
MWR 97-0676	Outboard Main Steam Isolation Valve (MS-AOV-A086C) Troubleshoot and Repair or Replace Ports
MWR 96-2145	Residual Heat Removal Heat Exchanger B Cleaning
MWR 96-2293	High Pressure Coolant Injection Turbine and Control Valve Chest

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Operations Control of Postmaintenance Testing of Diesel Generator 2

a. Inspection Scope (62707)

The inspectors discussed the diesel generator postmaintenance test with an auxiliary operator, control room supervisor, shift supervisor, operations supervisor, and operations manager.

b. Observations and Findings

On April 28, 1997, during discussions with an operator, the inspectors identified during performance of Procedure 2.2.20.2, "Operation of Diesel Generators from Diesel Generator Rooms," Revision 10 c4, that expectations for operations control of equipment were ambiguous. Diesel Generator 2 had been started, and prior to loading the diesel, the auxiliary operator locally observed three widely different voltages (600, 4200, and 6800) (Step 8.2.30) for the three phases of the generator. The operator discussed these observations with the test coordinator, the system engineer, who stated that the highest voltage of the three phases should be used to adjust diesel voltage in a later step. Neither the operator nor the engineer called the control room at that time and the test continued. The engineer stated he did not understand that the auxiliary operator was not in communication with the control room. When the auxiliary operator attempted to adjust the upper voltage (Step 8.2.33), the voltage would not adjust. At this point, the operator and the engineer terminated the test. During later discussions with the control room, the auxiliary operator learned that the control room indication had correctly displayed the highest voltage.

Inspectors questioned how auxiliary operator control of the equipment had been maintained while coordinating with engineering. The control room supervisor stated that the auxiliary operator was in control of plant equipment and that he did not find it inappropriate that the engineer was allowed to interpret the three disparate

voltage readings instead of terminating the test in obtaining control room assistance. The licensee re-emphasized the expectation that upon indication equipment may not be working or monitored properly, equipment should be put in a safe condition, and activities secured to determine the source of the problem. This guidance is consistent with operations procedures concerning proper conduct of equipment and testing. A night order was initiated and crew briefings were conducted to address the concern.

c. Conclusions

Inspectors found that expectations for auxiliary operators were not properly communicated or correctly understood for a test on the diesel generator. Apparent indication discrepancies were informally addressed and the test coordinator did not halt testing when unexpected indications were encountered.

M2.2 Failure to Sign All Steps During Postmaintenance Testing

a. Inspection Scope (61707)

Inspectors observed the postmaintenance test of the high pressure core injection turbine overspeed function.

b. Observations and Findings

On May 7, inspectors observed the high pressure coolant injection turbine overspeed trip test. Inspectors found that technicians were performing the steps in the sequence stated in the procedure and were properly communicating step requirements to other technicians participating in the test. The technicians were following the referenced procedure but had not signed some completed steps. Most of the steps, which had not been signed, were not applicable for this test. The licensee's expectations are that the steps be signed off as they are completed or as they are determined to be not applicable. This expectation was not being followed.

After questioning by the inspectors, the technicians began signing steps as they were completed. Since the observed activities appeared to implement the requirements of the procedure, the inspectors determined that the safety significance of this finding was minimal. It was apparent, however, that expectations to sign steps when accomplished were not being followed. Licensee supervision and management re-emphasized the requirements to sign steps as they are completed or determined to be not applicable.

c. Conclusions

Inspectors observed, during implementation of a test procedure, that technicians did not fully implement management's expectations to sign steps as those steps were completed. The test procedure requirements were implemented and the test was appropriately controlled.

M7 Quality Assurance in Maintenance Activities

M7.1 Increase in PIRs

a. Inspection Scope (62707)

Inspectors assessed the PIRs which were initiated during the inspection period for origination, apparent cause, and safety significance.

b. Observations and Findings

Inspectors noted a significant increase in the number of PIRs which were generated by mechanical and electrical maintenance personnel. Inspectors noted that I&C personnel continued to initiate high quality PIRs. The inspectors also noted that the general quality of PIRs and the number of the PIRs, which documented problems caused by maintenance activities, had increased.

Interviews with maintenance management, supervisors, and technicians indicated this improvement was due in a large part to corrective action taken in response to earlier problems associated with initiation of PIRs. The increase in the number of PIRs was partially attributed to the increase in site activity during the outage.

c. Conclusions

Inspectors noted an increase in the number and quality of the PIRs generated by the maintenance staff. This increase was due, in part, to corrective actions to address a historical reluctance of maintenance to initiate PIRs.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Open) Violation 50-/9416-02: inadequate 480v breaker system surveillance testing. The corrective actions implemented for this specific event were documented in NRC Inspection Report 50-298/94031.

The inspectors started a review of the STVP a third time for closure and identified the following problems (findings from the second review were documented in NRC Inspection Report 50-298/97002:

- The numbering system which tracks each item has numerous apparent omissions (i.e., SW-02-94, SW-05-94, and SW-07-94 were missing). The licensee has not yet determined why numbers were skipped or the status of missing items.

- Procedures 6.1SWBP.101 and 6.2SWBP.101, "RHR Service Water Booster Pump Flow Test and Valve Operability Test," Revision 2 c2 and 2 c1, contained steps to test that Service Water Valves SW-MO-89A and -89B automatically closed. The step required that the licensee ensure, rather than verify, the function occurred. The licensee's definition of ensure requires that, if the component does not automatically change positions, then the operator must manually place the component in the required position. Typically, no documentation of this manual action is required. Also, the steps were not marked as acceptance criteria and the acceptance criteria section did not list the valves as being required to automatically close. The licensee could not confirm that the valves closed automatically in the past based on the completed surveillance procedure. The associated operability evaluation is discussed in Section O2.2 of this report.

- Procedures 6.1DG.302 and 6.2DG.302, "Undervoltage Logic Functional, Load Shedding and Sequential Loading Test," Revision 2 c3 and 1, which contained steps to test that Service Water Pumps A, B, C, and D, Service Water Booster Pumps A, B, C, and D tripped as required, used the term "ensure" instead of "verify" that the trips took place. The acceptance criteria section required acknowledgement that all breakers tripped. The licensee could not confirm that the pumps/breakers tripped automatically in the past based on the completed surveillance procedure. After discussions with the licensee, the inspectors determined that for the service water booster pumps, the procedures contained separate steps that verified that the breakers did automatically trip; however, the steps were not considered acceptance criteria. The licensee determined that the service water pump breakers automatically tripped within the required time. The licensee's corrective actions will be reviewed as part of this open item.

- The STVP failed to include USAR Table VIII-5-5 required essential 4160v cables and motors testing (insulation test) on a yearly cycle. The cables and motors are currently being tested on an 18 month cycle.

- The STVP failed to include USAR Table VIII-5-5 required essential 480v breakers testing (overcurrent trip test) on a yearly cycle. The breakers are currently being tested on an 18-month cycle.

The last three items had been entered into the licensee's corrective action program and operability assessments were performed. Section O2.2 of this report discussed one of these operability assessments.

The licensee subsequently determined that the documentation of the STVP did not meet management's expectations regarding the adequacy of documentation. The licensee plans to perform a 100 percent verification to ensure the appropriate level of documentation is achieved. Inspectors will review this item when licensee's actions have been completed.

III. Engineering

E1 Conduct of Engineering

E1.1 Plugging of RHR B Heat Exchanger Tubes

a. Inspection Scope (62707)(37551)

Inspectors observed activities, held discussions with licensee staff, reviewed documentation associated with cleaning of the RHR B heat exchanger during the outage, and observed an interview with the maintenance technician who performed the heat exchanger cleaning.

b. Observations and Findings

On April 22, 1997, at approximately 3 p.m., inspectors observed cleaning of the RHR B heat exchanger. The RHR heat exchangers are vertical U-tube heat exchangers. At the time of the observation, approximately 450 of the 835 tubes had been cleaned using high pressure water and air. Discussions between the technician and work coordinator indicated that cleaning work was challenged by plugging of the tubes with mud. The inspectors questioned the technician on the percentage of tubes plugged. The technician stated that approximately a quarter of the tubes thus far had been plugged with mud. The inspectors promptly informed the work coordinator of the need to evaluate the as-found condition of the heat exchanger and immediately contacted the outage manager and engineering manager and discussed the same concern.

Two hours later, the inspectors found cleaning continuing with no method of recording the number of tubes clogged with mud or efforts to sample the removed plugs to aid in a root cause analysis. The inspectors again contacted the work coordinator, outage manager, and system engineering manager and informed them that mud was found plugging several tubes of the RHR B heat exchanger. The inspectors reiterated that the as-found condition regarding the extent of mud plugging should be properly documented and evaluated to determine the past operability and root cause. The inspectors expressed concern that the as-found condition was not being properly addressed.

Inspectors noted that Procedure 7.2.42, "Heat Exchanger Cleaning," Revision 10.2, required assessment of the as-found condition of the heat exchanger. The assessment involved checking the heat exchanger inlet and outlet plenum for mud

and silt, biological growth, and any other anomalies. The procedure required inspection of the tube sheet for plugged tubes as well as for evidence of sea life such as mussel shells or other substances which could plug tubes. The procedure also required photography of the tube sheet surfaces.

The technician noted that for most of these tubes, mud was not observed until after pressure or water flow was applied to a tube resulting in extrusion of dense mud from the outflow side of the tube.

On April 24, an engineer explained that high river level often resulted in silt buildup in the heat exchanger head and this was not a problem. He also provided a 1993 heat exchanger performance test, which he said was the last test on RHR B heat exchanger. He was unaware of the plugged tubes.

Later on April 24, based on interviews with the technician performing the cleaning and review of foreign material exclusion logs, the licensee estimated that 57 tubes had been plugged with mud. This estimate was based on the number of tube scrubbers which became stuck partially up the tubes and required about 90 pounds of pressure from the opposite direction to remove both the scrubbers and the mud.

Inspectors noted that the technician was the only person who had observed the as-found condition of the heat exchanger and it appeared that the engineers had not understood the as-found condition to date. The technician had stated that several other tubes without stuck scrubbers had been plugged with mud based on observations of the removal of mud with air and water pressure from the opposite end of the tube.

On April 25, the licensee discussed the operability, tube plugging, and testing of RHR heat exchangers with the NRC. The inspectors discussed prior RHR heat exchanger performance testing. The licensee provided tests of RHRs A and B heat exchangers performance by the test data log. The licensee stated that RHR B heat exchanger for performance testing had not been performed prior to cleaning.

The plant engineering supervisor then interviewed the technician to characterize the as-found heat exchanger condition and found that the "57 tubes" number was a mid-cleaning number of tubes. Scrubbers, typically propelled through tubes by water pressure, had become stuck in mud a foot or so up the tubes. The technician decided to quit using scrubbers when several became stuck. The foreign material exclusion log showed this number was 57. He then started blasting a water-air mixture through from the other side to clear the mud and scrubbers by water pressure as well as clear out all other tubes filled with mud. The technician estimated that 10 to 25 percent of the tubes of Rows 1 through 14 of the Heat Exchanger had semi-solid streams of mud extruded during cleaning. Tubes 14 through 24 were relatively clean and mud plugged tubes had occurred in groups. Another interview of the technician occurred and was recorded by the acting plant

engineering supervisor to address further questions. The inspectors attended the second interview. The inspectors noted that no samples of the mud were obtained to assist the root cause determination.

Based upon discussions with the technicians the licensee calculated that a minimum of 94 tubes to a maximum of 175 tubes could have been plugged. These estimates included the 26 permanently plugged tubes. The analytic design limit of heat exchanger tube plugging is 193 tubes based on 1995 heat exchanger performance test data. Using heat transfer data from earlier in the outage and given a factor of 0.0025 hour-foot^2-degree F/btu, the licensee conservatively estimated that 175 tubes were plugged to the extent that no flow could occur. The licensee concluded that the heat exchanger was capable of performing its design function throughout its service life if service water temperature was less than 85°F. The licensee stated that their commitments regarding heat exchanger cleaning and testing were being reviewed.

On May 6, the licensee discussed an evaluation of the effects of the plugged tubes with the NRC, including plant computer information on the head exchanger during the shutdown. The licensee concluded that with the worst case design service water temperature of 90°F, the heat exchanger would not have been operable. Maximum service water temperature to support an operable heat exchanger was calculated to be 85°F. Review of actual river water temperatures found the maximum during the 1996 summer was 83°F.

In order to assess the safety significance of this issue, inspectors determined that RHR Exchanger B had last been cleaned in March 1993. Performance testing in October 1995 indicated the heat exchanger was and, therefore had been operable and would have performed its design functions under worst case design service water temperature assumptions. The service conditions during this time period included a 10-month shutdown during which RHR Heat Exchanger B was the preferred shutdown cooling heat exchanger. Altogether, this indicated that service was maintained over the period and that the heat exchanger had remained operable without cleaning.

Further evaluation of licensee service water commitments, of the licensee's root cause determination, and safety significance of this condition will be followed by a URI (50-298/9705-03).

c. Conclusions

Maintenance failed to identify and accurately characterize extensive mud plugging of RHR heat exchanger tubes. Engineering did not identify and characterize past operability of the heat exchanger until after significant NRC intervention.

E1.2 Fuel Movement

a. Inspection Scope (62726)(37551)

The inspectors observed fuel movement, reviewed Procedure 10.25.2, "Refueling - Core Shuffle," Revision 3, and held discussions with the reactor engineer and the reactor engineering supervisor.

b. Observations and Findings

On April 14, 1996, the inspectors observed the licensee move fuel between the reactor vessel and the fuel pool. The inspectors observed that the reactor engineer on the refueling bridge was not visually verifying that the fuel move listed on the procedure was the same as the fuel movement step read by the operator. This verification was a management expectation. The reactor engineer, based on what he heard, confirmed that the correct fuel bundle was removed from and placed in the correct location.

The inspectors questioned the reactor engineering supervisor whether the reactor engineer was meeting his expectations for verifying fuel movement while on the refuel bridge. The reactor engineering supervisor interviewed the reactor engineers and reviewed the procedure. The reactor engineer supervisor noted that neither the procedure nor the reactor engineers met his expectations. As interim corrective actions, the reactor engineer supervisor met with the reactor engineers to communicate his expectations. One action included audible concurrence with each fuel movement on the radio link with the control room. A PIR was written to initiate long-term corrective actions.

On April 28, 1997, during observation of control room operator coverage of fuel movement, the inspectors noted that reactor engineering was not providing an audible concurrence with fuel moves over the radio. The reactor operator asked if the reactor engineer had a radio to which the senior reactor operator on the fuel bridge responded, "No." The inspectors then asked the control room supervisor if the reactor engineer's lack of concurrence was consistent with expectations. In response, the control room supervisor communicated with the refueling floor and was told that the reactor engineer was not keying his radio properly for concurrence.

The inspectors did not identify any safety issues regarding fuel movement as a result of these observations but noted that reactor engineers did not appear to implement consistent performance.

c. Conclusions

Inspectors identified that reactor engineers and the reactor engineering supervisor had not implemented expectations for reactor engineer duties during fuel movement.

E2 Engineering Support of Facilities and Equipment

E2.1 Evaluation of Emergency Diesel Generator Woodward Governor Failure Modes

a. Inspection Scope (37557)

The inspectors reviewed an evaluation of the emergency diesel control modification, particularly the Woodward EGA and 2301 governors with respect to potential failure modes of the diesel governors in the control system.

b. Observations and Findings

On April 23, 1997, the inspectors completed a review of a 10 CFR 50.59 safety evaluation associated with the emergency diesel generators. The inspectors specifically reviewed the failure modes analysis for the new design diesel generator governor and control system to determine if governor failure modes had been properly evaluated. Both the new and old design governors were designed to fail in the no load direction. Therefore, on Woodward governor failure, the diesel control system would be expected to pick up and control with the mechanical governor as speed decreased from 60.1 Hz to 59.8 Hz. This governor design response was unchanged from the prior configuration.

c. Conclusions

The design of the new Woodward governor interface with the diesel speed control did not appear to introduce a new failure mode.

E2.2 Failure to Consider Effect of Procedures on Core Reload Analysis

a. Inspection Scope (35571)

Inspectors reviewed actions to address the failure of the core reload evaluation to consider operations allowed by procedures.

b. Observations and Findings

Inspectors noted that the core reload concern, as documented in NRC Inspection Report 50-298/97-03, Unresolved Item 97003-01, identified that plant operating procedures had not been addressed to determine if operations outside of the core reload analysis were allowed by procedures. Review of the licensee's actions found

that several procedures and operating conditions had not been properly addressed. These areas included operation with reduced feedwater heating, inoperable safety relief valves, nonconservative thermal limits during single loop operation, and other concerns.

To review the interim corrective actions for plant start up, the licensee participated in an NRC conference call on May 15, 1997. The individual issues were discussed in detail and addressed the applicable procedure changes and the TS requirements affected by the reload analysis. Based on the licensee's discussion and review of a sample of the procedure changes, the inspectors determined that the licensee's actions appeared to have addressed the concerns which affected start-up and power operation.

c. Conclusions

The licensee identified that the operational conditions inherent in the core reload analysis were not properly implemented into various plant operations procedures (i.e., procedures allowed operation with reduced feedwater heating, inoperable safety relief valve, nonconservative thermal limits during single loop operation, and other concerns). Inspectors verified that interim corrective actions addressed this issue prior to plant startup.

E7 Quality Assurance in Engineering Activities

E7.1 10 CFR 70.24 Criticality Monitors

a. Inspection Scope (37551)

Inspectors reviewed the licensee's implementation of 10 CFR 70.24, which requires criticality monitoring programs for fuel handling.

b. Observations and Findings

Inspectors noted that criticality monitors were not present at fuel truck unloading on the 903 foot level of the reactor building. Inspectors questioned if a recent quality assurance (QA) audit on fuel handling had examined implementation of 10 CFR 70.24. In response, QA identified Condition Report 94-0293, dated June 14, 1994, where a failure to comply with requirements had been closed without corrective actions. QA initiated PIR 2-12781 to document this concern. Resolution of this concern will be followed by an URI 50-298/97005-04.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Violation 50-298/9610-02: failure to identify/correct valve factor capability. Core Spray System Injection Valve CS-12A was determined by calculation to have been inoperable (unable to open) for an extended period because

of a pressure locking condition that could develop immediately following a loss-of-coolant accident. The licensee had failed to identify the inoperable condition because of a mistake in interpreting a diagnostic test of this valve in 1993, where a valve testing sensor reversal occurred resulting in a gross undermeasurement of the unseating thrust. Within the framework of this issue and a contributing factor in the delay in identifying the inoperability, was a contractor's calculation of the rate at which the valve bonnet pressure would decay. The licensee had used this calculation without questioning or challenging it, despite numerous industry test results indicating that valve bonnet pressures typically decay at rates much lower than that predicted by the calculation.

As corrective action, the licensee modified Valves CS-12A and CS-12B (alternate train valve considered degraded but not inoperable from the same mechanism) by providing a vent path for the bonnet. These modifications virtually eliminated the potential for these valves to pressure lock. The licensee also reviewed test traces for the entire motor-operated valve population for anomalies similar to that occurring on Valve CS-12A but did not identify any examples. As part of a broad-based improvement to design control procedures, the licensee modified Procedure 3.4.7, "Design Calculations," Revision 11, and Procedure 3.4.8, "Design Verification," Revision 7, to strengthen the design input verification/validation process. The motor-operated valve program was enhanced to include the trending of motor-operated valve anomalies.

To preclude additional misinterpretations of test data, the licensee also modified Maintenance Procedures 7.3.35.5, "Testing of Motor-Operated Valves Using Votes," and 7.3.35.6, DP Testing of Motor-Operated Valves Using Votes." This included information specifically addressing the identification of sensor reversals.

The inspectors questioned the licensee as to whether the contractor calculation of bonnet pressure decay, subsequently shown to be significantly inaccurate, had been considered under the requirements of 10 CFR Part 21, "Reporting of Defects and Noncompliance." The licensee stated that this had not been considered. Because this calculation was procured under the requirements of 10 CFR Part 21, the subsequent discovery of the invalidity of the calculation would have required review. The licensee's review determined that the vendor had used valve performance values supplied by the licensee which were inaccurate, causing the calculation to be inaccurate. Additionally, the licensee noted that the procedures for review of services could be strengthened to require an evaluation of potential 10 CFR Part 21 concerns if defects were identified in services. This appeared to address the issues.

The inspectors reviewed the procedure changes referenced above and the licensee's motor-operated valve trending program, verifying in each case that the reported change was made and that the changes appeared sufficient in scope to lessen the

chance for a repeat of this event. The inspectors determined that the licensee had taken both specific and generic issues into account regarding this incident and had adequately addressed each of these issues.

IV. Plant Support

R7 Quality Assurance in RP&C Activities

R7.1 Failure by Operations to Document Repeated Cases of Contamination

a. Inspection Scope (71750)

Inspectors reviewed operations and radiation protection response to cases of unexpected contaminations.

b. Observations and Findings

On May 1, 1997, after an unexpected reactor scram, a licensed operator draining the scram discharge isolation volume received minor contamination. The process to drain the scram discharge isolation volume was different than normal operations because the system was undergoing modification of the vent and drain valves. During the modification, draining was conducted via a level instrument drain line rather than the routine drain piping. Inspectors noted that no PIR was issued to document this unexpected contamination. On May 7, an unexpected reactor scram occurred requiring another draining of the scram discharge isolation volume. Inspectors noted that floor contamination as well as personnel contamination occurred and were logged. No PIR was initiated for either case.

Inspectors noted that contamination levels were low and were less than the administrative threshold for requiring a PIR. Therefore, operations and radiation protection personnel perceived no requirement for issuing a PIR. During discussions with the radiation protection manager, inspectors emphasized that unexpected contaminations were occurring and continuing without documentation of the condition or efforts to prevent recurrence.

The radiation protection manager emphasized his expectation to the radiation protection staff that all unexpected contamination should result in a PIR in order to reduce contaminations. The following week, five PIRs were issued to document unexpected contaminations. This indicated a higher standard of problem identification by the radiation protection staff.

c. Conclusions

Inspectors identified that unexpected contaminations of operators were not being addressed to preclude future contamination events. After discussions with radiation protection management, several more occurrences were documented by radiation protection staff.

V. Management Meetings

XI Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on May 20, 1997. The licensee acknowledged the findings presented. During the exit meeting, the licensee expressed concern that the inspectors had not discussed some major improvements and efforts which the licensee had undertaken during the outage. As examples, the licensee noted the torus suction strainer upgrade, main steam safety relief pilot valve seat replacement, evaluation of diesel generator cylinder liners, modification of the scram discharge isolation volume to add additional redundant isolation valves to met standard NRC design, evaluation of Information Notice 96-48, "Motor-Operated Valve Performance Issues," concerning Limortorque Motor Performance and modification of a motor, evaluation and modification of the electrical distribution system to address a potential undervoltage concerns, and modification of containment isolation penetrations to address Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," concerns. The inspectors acknowledged that these specific issues had not been discussed during the exit meeting. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Bennett, Licensing Supervisor
D. Billesbach, Work Control Manager
T. Brown, Emergency Preparedness Manager
J. Dillich, Maintenance Manager
F. Diya, Design Engineering Manager
C. Gaines, Outage Manager
P. Graham, Vice President, Nuclear Energy
M. Hale, Radiological Protection Manager
M. Peckham, Plant Manager
J. Pelletier, Engineering Senior Manager
R. Sessoms, Quality Assurance Senior Manager
R. Wachowiak, Reliability Engineering Supervisor

INSPECTION PROCEDURES USED

IP 37751: Onsite Engineering
IP 61726: Surveillance Observation
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92902: Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-298/9705-01	URI	CRD Housing supports procedure requirements in contrast with USAR (Section O2.1).
50-298/9705-02	IFI	Weak operability assessment (Section O2.2)
50-298/9705-03	URI	RHR heat exchanger commitments (Section E1.1)
50-298/9705-04	URI	Failure to implement 10 CFR 70.24 criticality monitor requirements (Section E7.1)

Closed

50-298/9610-02	VIO	Failure to evaluate valve (Section E8.1)

Discussed

50-298/9416-02	VIO	480v breaker system surveillance testing inadequate (Section M8.1)
50-298/9703-01	URI	Procedures not evaluated in the core reload analysis (Section E2.2)

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
CRD	control rod drive
I&C	instrumentation and control
IFI	inspection followup item
PIR	problem identification report
QA	quality assurance
REC	reactor equipment cooling
RHR	residual heat removal
STVP	surveillance test validation program
TS	Technical Specification
URI	unresolved item
USAR	Updated Safety Analysis Report
VIO	violation