ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-14

License: DPR-46

Licensee: Nebraska Public Power District
1414 15th Street
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: October 1 through November 11, 1995

Inspectors: M. H. Miller, Senior Resident Inspector
C. E. Skinner, Resident Inspector

Approved: Terrence Reis 12-18-95
T. Reis, Acting Chief, Project Branch C Date

Inspection Summary

Areas Inspected: Routine, anno ed inspection of onsite review of events, operational safety verification, plant support activities, surveillance and maintenance observations, followup of corrective actions for violations, and in-office review of licensee event reports (LERs).

Results:

Operations

- The licensee failed to recognize that performing a full-core offload for refueling was inconsistent with normal usage of the spent fuel pool as defined in the Updated Safety Analysis Report (USAR) (Section 2).

- Licensed operators did not anticipate cooldown rates during a plant shutdown, resulting in group isolations. The operators responses to the cooldown and unexpected engineered safety features (ESF) actuations were prompt and appropriate (Section 2.2).

Maintenance

- Approximately 10,000 gallons of reactor coolant inventory was inadvertently drained from the refueling cavity due to contract personnel inadvertently repositioning a valve in a main steam line plug in the reactor cavity (Section 3.4).

- Instructions for installing a jumper on a nonsafety breaker control panel were incorrect and resulted in an unexpected ESF actuation when power was lost on a safety-related bus (Section 3.3).

- Permission to perform steps of the (DG) 1 18-month overhaul out of order was not controlled in writing. The procedure also did not identify those steps which must be performed in order. Licensee management has not clarified expectations regarding this issue (Section 4.3).

- A gouge on a safety-related valve disc was not identified by licensee receipt inspectors, maintenance technicians, nor system engineers (Section 4.4).

- Maintenance practices on DG 1 work were poor, resulting in several problems, including incorrect size terminal lugs, poor air-piping fit-up, and poor mechanical piping fit-up. The licensee did not properly implement lube oil pump replacement, resulting in a broken pump shaft (Section 4.2).

- Licensee management ordered a stop work due to inadequate implementation of foreign material exclusion controls (Section 4.7).

Engineering

- The licensee failed to recognize that operation of the standby nitrogen system was affected by both a stack of concrete blocks which corrected a security vulnerability and the discontinuation of secondary containment testing on an airlock door (Section 3.6).

- The installation of fiber glass sealant over the steam tunnel blowout panels caused the blowout panels to function at a less conservative pressure, reducing the ability to mitigate a steam line break (Section 3.7).

- The DG 1 design change was difficult to implement, resulting in several delays and requiring several engineering coordinators on each shift to resolve concerns (Section 4.1).

- Licensee management ensured that individual, specific problems encountered during the DG 1 design change were individually addressed before the design change was implemented on DG 2 (Section 4.2).

- Licensee engineering and quality assurance staff identified and corrected procedural requirements for service water booster pump windmilling during refueling and operation conditions (Section 5).

Plant Support

- A technician performing work in a contaminated instrument rack removed his hand from the contaminated area and operated a communications microphone, potentially spreading contamination.

- Radiation protection staff identified three cases of contamination being brought to the site in personal protective clothing laundry (Section 6.3).

- Radiation protection staff identified that a vendor shipped a package of a limited quantity shipment that had maximum surface radiation levels of approximately 2 mr/hr (Section 6.4).

- Security staff did not identify an inadequately lighted area under a trailer (Section 6.5).

Summary of Inspection Findings:

Open Items

- Unresolved Item 298/9514-01 (Section 2.1)
- Unresolved Item 298/9514-02 (Section 3.7)

Closed Items

- Violation 298/93202-02 (Section 8.1)

- LER 298/95-014 (Section 9.1)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period the plant was operating on an end of cycle coast down from 96 percent power. On October 14, 1995, at 1:15 a.m., the plant was manually scrammed for a scheduled refueling outage. After that manual scram, two separate ESF actuations occurred on low reactor level. The first was due to the feed pump transferring to a lower speed immediately after the scram, causing a reduction in level and the expected group isolations which occur at the low level. The second occurred about an hour later when the cooldown rate was higher than expected and operators appropriately closed main steam isolation valves (MSIVs), causing a shrink and a resulting actuation on low level. These actuations are discussed in Section 2.

The refueling outage continued through the end of this inspection report period including fuel off-load and core shroud inspection, as well as significant outage work on the main turbines and the emergency DGs. The outage, scheduled to take 55 days, included work on motor operated valves, the main turbine, 10 year inservice inspection containment and piping testing and walkdowns, diesel generator modifications, 125/250 volt batteries, safety relief valve vacuum breakers, high pressure core injection system vacuum breakers, and replacement of 500 feet of the steam extraction line.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Spent Fuel Pool Cooling During Fuel Off-Load

On October 20, 1995, the NRC identified to the licensee concerns with the utilization of the spent fuel pool and cooling systems. The USAR indicated the spent fuel pool and cooling systems were designed, under normal circumstances, to accommodate a one-third core offload. The licensee was in the process of conducting a full core offload to the spent fuel pool. The licensee, conducting defueling operations, immediately stopped fuel movement and researched the design basis of the spent fuel pool. The licensee determined that the pool and cooling systems were designed to accommodate a full core discharge and fuel could be off-loaded at a linear rate that would result in a full core off-load to the spent fuel pool after 11 days. The licensee maintained a steady rate of fuel offload bounded by the USAR heat removal assumptions for the core decay heat. Further licensee analysis was performed which identified significant conservatism in the assumptions associated with the USAR calculations. The licensee determined by 10 CFR 50.59 analysis, that so long as the spent fuel was maintained below 150°F, residual heat removal (RHR) cooling was not immediately needed as was implied in a 1978 Safety Evaluation Report. In the event temperature exceeded 150°F, the licensee determined that margin was available to provide RHR fuel cooling assistance before the spent fuel pool reached 160°F. Further NRC review of the licensee's 10 CFR 50.59 analysis is continuing in the Office of

Nuclear Reactor Regulation (NRR). The utilization of the spent fuel pool and cooling systems is an unresolved item (298/9414-01).

2.2 Unanticipated ESF Actuations During Shutdown for Scheduled Refueling Outage

On October 14, 1995, two unanticipated ESF system actuations occurred during shutdown activities at the start of the 1995 refueling outage. The licensee reported each in accordance with the requirements of 10 CFR 50.72.

At 1:24 a.m., during the scheduled manual scram shutdown from 22 percent power, the feed pump control system abruptly changed speed, causing the operating feed pump controller to lock to the current feed pump flow rate. This, coupled with the expected drop in reactor vessel level at the reactor scram, resulted in a drop in level from a normal 35 inches to 10 inches.

At 10 inches an expected scram signal and automatic Group Isolations 2, 3, and 6 occurred, isolating the reactor water cleanup system, the reactor building ventilation system, and the RHR shutdown cooling system penetrations. This was the first of two ESF actuations. The licensee was not able to immediately recover the feed pump controller and so started the reactor core isolation cooling (RCIC) pump to add inventory to the vessel.

Later, at 1:55 a.m., control room operators were removing core decay heat at a rapid rate due to the steam usage of the plant auxiliary loads, feed pump, turbine bypass valves, and RCIC steam use and cold feed input, which dropped reactor temperature at a faster rate than expected. The cooldown rate approached 100°F per hour. To limit the cooldown, the licensee closed the MSIVs. As a result of the MSIV closure, the reactor level again dropped below 10 inches, causing the same ESF actuations noted above.

After MSIV closure, the cooldown rate was limited, and RCIC continued to add inventory to recover level. One MSIV was then opened to allow continued cooldown using the turbine bypass valves. The licensee continued the cooldown without further incident. The licensee placed the plant on RHR shutdown cooling at 4:04 p.m. and continued with the planned outage schedule.

The resident inspectors will review the control room crew actions and plant parameters associated with the event, as well as the licensee's event analysis, during routine followup of the forthcoming LER.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

The inspectors observed control of defueling operations from the control room and fuel pool and observed that record keeping and operator verbal communications were well controlled and appeared appropriate. Operators assured that fuel movement did not exceed fuel pool heat removal assumptions by complying with a Station Operations Review Committee approved analysis of maximum allowable rate that fuel bundles could be removed from the vessel and placed in the spent fuel pool. Inspectors observed control of fuel movement and verified on multiple occasions that this rate was not being exceeded.

3.2 Plant Tours

During plant tours, the inspectors observed preparations for the outage and work-in-progress. Inspectors noted protection of the Division 2 safety system required for safe fuel cooling systems and inventory control. Protected equipment was appropriately identified to plant staff by use of labels designating the equipment as protected, as well as use of danger tags on specific components such as valves and breakers.

3.3 Inadvertent ESF Actuation Resulting in Transfer of Bus F Power Source

On October 26, 1995, the licensee installed a jumper in a nonsafety breaker control panel to allow work on a nonsafety-related relay. The jumper points were incorrectly specified. The jumper was installed in accordance with the instructions, which resulted in a sensed low power on safety-related Bus F and a resulting fast transfer of Bus F from the preferred to the 69 kV startup power source. Safety-related Bus F was not a protected bus at this particular time in the outage. However, the fast transfer is an ESF function and, therefore, reportable under 10 CFR 50.72. A condition report (CR) was written to address the incorrect jumper instructions and the actuation. In the analysis following the actuation, the licensee determined that no equipment damage had occurred and that the root cause of the ESF actuation was inaccurate work instructions.

The inspector noted that the licensee had not performed a rigorous evaluation to determine if high resistance heat effects or current ratings problems had occurred as a result of this improper jumper. The licensee pointed out that a 15 amp fuse had blown to protect the 125 volt dc circuit and, therefore, no relay damage or other component was expected during this event. The inspector noted that, although the ratings of the installed components experiencing the unexpected current surge were greater than the 15 amp fuse, the licensee had not addressed the rating of the jumper. Their investigation determined that the jumper was not rated for the current which occurred and, as a result, the clamps on the jumper attachment point which experienced high voltage had been heated to the point of failure. Further questions by the inspector and investigation by licensee engineering personnel determined that, although the jumper attachment clamp had been heated to the point of failure, no foreign material was found in the panel, and no adverse effects were expected inside the panel since all components inside the panel were sealed and terminal points were protected from foreign material by flash guards. This appeared to have resolved the inspector's concern. Further review of this issue will occur during review of the LER.

3.4 Loss of Reactor Cavity and Spent Fuel Pool Inventory

On October 31, 1995, the licensee identified that approximately 10,000 gallons of reactor coolant inventory in the refueling cavity had been lost. The level decreased approximately 1 to 2 inches and was replenished from condensate makeup. The licensee identified that at approximately 6:30 a.m. vendor's equipment in the refueling cavity had become entangled and inadvertently repositioned a ball-valve that was an integral part of a submerged main steam line plug, allowing a flow path to the main steam line drains. Since the drainage was not observed, inventory continued to flow from the refueling cavity without being identified. Within 30 minutes the spent fuel pool surge tank low level alarm alerted operators. Within approximately 40 minutes of the alarm, operators identified the source of the inventory loss and repositioned the valve. The licensee stopped work on the refueling floor to emphasize the need to properly control the valve positions of underwater valves to staff and contractors working in the refueling area.

Although the loss of control of the path which drained the reactor cavity was an example of poor control of reactor coolant system inventory, the safety significance of the specific event was minimal. The following considerations mitigated the significance of the loss of inventory: (1) the change in reactor cavity and spent fuel pool level was approximately 1 inch; (2) both the Train B RHR and core spray pumps were operable and immediately available for actuation from the control room, to provide a range of 4,000 to 15,000 gpm injection, while the leakage was about 100 gpm; (3) the loss of inventory was alarmed in the control room by loss of spent fuel pool surge tank level; (4) the path of leakage was identified by the increase in the radwaste sump and collection tank levels; (5) once the leak path was identified, it was quickly secured by operators dispatched to close the manual isolation valves; and (6) the MSIVs were danger tagged close to preclude large inventory losses. Remotely operated valves were available to be operated from the control room.

3.5 Control Room Activities

Inspector observations of control room activities included several control room staff turnovers, several crew meetings, including status meetings as well as progress of outage work and job briefings. Operator involvement was evident, and operators identified and resolved several concerns about outage scheduling and equipment and system configuration.

3.6 Configuration Control of Standby Nitrogen Injection System

The NRC inspector identified that the licensee had not evaluated the potential impact a compensatory security measure, which consisted of a stack of cement blocks placed in front of an obsolete door, may have on the secondary containment structure. In reviewing the inspectors concern, the licensee identified that standby nitrogen injection system access was required via that door. The licensee identified that, in the event that a train of standby nitrogen injection was required, secondary containment may have been breached since the interior airlock door was no longer tested as a secondary containment boundary. The licensee then tested the interior airlock door and found it to be operable and therefore, no breach of secondary containment would have occurred in the event that the train of standby nitrogen injection was required to be utilized. The licensee has reinstituted testing of the airlock door. The inspectors concluded that there was no direct safety significance of this finding because the secondary containment boundary remained intact; however, it highlights the need for the licensee to more systematically address safety implications of changes made to the facility.

3.7 Steam Tunnel Blowout Panel Configuration Control

On November 8, 1995, the inspectors identified that the blowout panels on the turbine side of the steam tunnel were not configured in accordance with existing calculations and that a coating, apparently of a fiber glass or epoxy substance, had been placed over the blowout panels, potentially altering their material characteristics and causing the blowout panels to have higher strength. This would be nonconservative for the blowout panels design basis function. The inspector also identified that, because the main panel was distributed across three main steam lines, the panel may not clear the blowout port within the assumed time. Additionally, the calculation did not allow margin for the main panel hanging up on the main steam lines and partially blocking the steam exit through the blowout port. This vulnerability is a concern since the blowout panel in the steam tunnel protects the structural integrity of the secondary containment. Steam tunnel blowout panels also may protect primary containment from being pressurized via the main steam and main feed line sleeves. Pressure from a main steam line break can propagate through the main steam and feed line sleeves to the annulus between the biological shield and the primary containment. If this annulus is over pressurized, primary containment could be inappropriately pressurized from the outside and exceed its designed differential pressure.

The licensee's safety analysis of this condition was ongoing at the end of this inspection period. The issue will be tracked as an unresolved item (298/9514-02).

4 MAINTENANCE OBSERVATIONS (62703)

4.1 DG Design Change Implementation Concerns

On October 23, 1995, on three separate occasions, inspectors observed implementation of DG 1 design change. This design change involved several modifications to pneumatic, electrical, and mechanical systems and would result in significant changes to DG 1 logic. The inspectors observed that the technicians performing the design change were often unable to continue work due to confusion and inability to determine what configuration the diesel wiring should be in at that stage of the design change. The inspectors observed that, when confronted with confusing instructions or a lack of assurance of the actual DG 1 wiring configuration at that time in the modification, technicians stopped immediately and attempted to determine proper configuration. This was observed several times. The inspectors also noted that several field changes had been made to the design change after it had been released for work. These changes primarily involved clarifications, requirements, and corrections.

Inspectors discussed concerns with licensee management that, given the complexity and importance of the DG work, frequent occurrences where work could not continue because of difficulty of implementing the change indicated a need for closer management involvement. The licensee management agreed to evaluate the DG design change work.

Based on the inspectors' observations, as well as an independent evaluation by quality assurance, the licensee management acknowledged that the DG design change was not well written and was sufficiently complex to cause difficulty during the implementation. Further, turnovers during day and night shift technicians, and performance of stages of the design changes in parallel, increased the complexity and difficulty of the change. The licensee management assigned an additional three engineers per shift to the current two engineers assigned per shift to provide for coordination and resolution of design change issues. In discussions with the inspectors, the licensee stated that, because of the complexity of the design change and the difficulty of its implementation, the licensee would perform continuity checks as well as visual wiring checks of the design change at the conclusion of its implementation. These appeared to address the inspector's concern regarding potential loss of configuration control due to the complexity of this change and the difficulty of its implementation.

4.2 Improper Work Practices During DG 1 Design Change

On November 3, 1995, the licensee management identified that work on the DG design change as well as work on the DG 18-month overhaul would be closely examined for implementation problems. The licensee identified multiple occasions where piping flanges, air line connections, and terminal lug installations were not proper. These connections were then broken and properly reattached. The licensee expressed concern that these particular installations had been done with poor work practices and were not in accordance with the expected standards of work.

On November 9, the licensee initiated a 15-second test run of DG 1. DG 1 rolled successfully, however, the speed fluctuated considerably. After shutting down DG1 the licensee readjusted the governor with the help of the vendor technical representative, who had identified that the switches on the governor were not set in accordance with the vendor manual. After these actions the diesel 2-minute run was started. The diesel was immediately shut down due to an uncontrolled increase in speed before it reached its overspeed setpoint. A nonconservative overspeed setpoint was also identified, which was corrected. Further licensee trouble-shooting determined that the governor was not controlling properly and was sent back to the vendor. Additional DG runs resulted in multiple pump problems, including the failure of a lube oil pump shaft due to improper reassembly. At the conclusion of the inspection period, further DG 1 diagnostics were continuing.

Inspectors expressed that the lessons learned from DG 1 concerning the design change and 18-month maintenance overhaul would be useful on DG 2. The licensee agreed and indicated these lessons learned were already being included in the DG 2 design change which was scheduled for implementation within the next 2 weeks. The inspectors expressed concern that licensee efforts appeared to be directed toward fixing specific DG 1 problems, with much less emphasis placed on identification and correction of programmatic problems. Licensee quality assurance raised issues with both individual and programmatic problems for both continuation of DG 1 recovery and implementation of the design change and 18-month overhaul on DG 2. Inspectors and licensee quality assurance pointed out the need to identify and resolve programmatic errors, and ultimately their root causes, which should have been corrected before DG 2 work started.

The licensee management's response to concerns identified by the inspectors as well as concerns identified by the licensee appeared appropriate. However, the programmatic issues and root causes were not promptly addressed until after NRC involvement. The inspectors expressed concern that corrective actions may not be in place before work commenced on DG 2. The licensee stated that, without proper corrective action being implemented, DG 2 work would not commence. This satisfied the inspectors' concerns.

The inspectors considered it appropriate that licensee technicians stopped when confusion or concerns were identified and that quality assurance was involved. Licensee quality assurance also identified a plan for ensuring appropriate root causes were addressed before work on DG 2 commenced. Although programmatic concerns were not promptly addressed, licensee management identified and performed wiring configuration and continuity checks and additional testing and inspection of DG 1, which addressed immediate inspector concerns for inadequate work instructions. Continued followup of DG modification work will be performed as part of routine resident inspector activities.

4.3 Sequential Performance of Steps Not Required For Overhaul of DG 1

On October 20, 1995, the inspectors observed mechanical maintenance technicians performing Maintenance Work Request (MWR) 95-2343, the 18-month overhaul of the DG. The MWR references Maintenance Procedure 7.2.53.1, "DG Engine Mechanical Inspection," Revision 11. While reviewing the procedure, the inspector noted that steps were not performed in sequence and maintenance technicians did not initial the steps in the order listed in the procedure. Step 6.1 required that the sequential performance of steps is mandatory unless otherwise stated or approved by the maintenance supervisor or designee. When the inspector questioned the maintenance supervisor at the job location, it was apparent to the inspector that this supervisor was uncertain as to who his maintenance supervisor was. It was determined later that the maintenance supervisor working nights gave permission to perform these steps out of order. The permission that he gave was oral, not written. The inspector discussed concerns with the maintenance manager who, at the end of this inspection period, had not yet determined what, if any, corrective actions would be taken.

The inspector expressed concern that the practice of allowing the sequencing of procedural steps verbally diluted the significance of procedures, and left the licensee vulnerable to individual errors in judgment and retraceability concerns. The licensee agreed to reevaluate its processes.

4.4 Maintenance on Service Water Valve SW-MO-36

On November 1, 1995, while the inspectors were observing maintenance technicians performing MWR 95-3491, the inspector noted that the disc portion of the valve was gouged. Upon questioning, the maintenance technician stated he did not know of the gouge and had nothing in his work package addressing the issue. Also, the gouge had not been evaluated by engineering and was not documented by the receipt inspection. Later licensee evaluation determined that this concern had little safety significance since the gouge was in a nonstructural area of the disc and the strength of the valve was not affected. However, this inspection finding demonstrated a lack of questioning attitude by licensee personnel in several organizations.

4.5 Correction of DG 1 Terminal Lug Installation

On November 5, 1995, the inspector witnessed electricians re-lugging terminals due to earlier installation of lugs of incorrect size. CR 95-1174 identified that the wrong size lugs had been installed during Design Change 93-024, which was just completed. As part of the corrective actions to the CR, MWR 95-3943 was written to correct the problem, which referenced Maintenance Procedure 7.3.28.1, "Lead Lift and Installation of Local Lead T and B Lugs," Revision 2. The maintenance technicians and the electricians appeared to be adequately trained and the documentation was appropriate to perform the required activity. Also, a quality control inspector was assigned to verify that the electrical connections were correct.

4.6 The Replacement of Internals of RHR Heat Exchanger A

On November 6, the inspector observed the replacement of internals of RHR Heat Exchanger A SW Outlet Valve SW-MO-89A, in accordance with MWR 95-3586. The workers followed the procedures and used adequate foreign material exclusion controls. The work appeared to be performed appropriately.

4.7 Stop Work Ordered by Licensee Management for Inappropriate Control of Foreign Materials

On October 27, 1995, the licensee management determined that work requiring foreign material exclusion was not being conducted properly at most work sites. Licensee management determined that, although there were no indications that foreign material had been introduced into plant systems, the practices being used by plant technicians were not proper. The licensee ordered a stop work for all jobs except refueling operations, and local leak rate testing, in order to emphasize the need for proper control for material. Licensee quality assurance observations had identified conditions where foreign material exclusion boundaries were not set properly and were used to exclude people from the job site. Also, materials and trash were stacked within the boundary of foreign material exclusion areas. During management discussion with supervisors, licensee management emphasized the need for clear understanding by plant technicians as to the reasons for foreign material control as well as the need to understand specific requirements for foreign material exclusion procedures and, further, that these procedure requirements needed to be implemented. After these discussions the licensee allowed specific jobs to resume work based on verification that proper foreign materials controls had been implemented.

NRC inspectors attended these sessions. Inspectors had previously noted, during routine observations, that foreign material controls, although adequate, were marginal. No violations of safety significance had been observed.

5 ONSITE ENGINEERING (37551)

The licensee's safety-related service water system requires service water pumps and booster pumps to perform accident functions. During this inspection period, concern was identified by the licensee for windmilling the booster pumps during planned operations at power, transient, shutdown, or refueling conditions. During windmilling, the pressure of the service water system in the RHR heat exchangers is less than the pressure of the spent fuel pool or reactor vessel fluid. In this case, leakage from an RHR heat exchanger tube would be expected to flow into the service water and be subsequently discharged in the outfall. Analysis showed that 10 CFR 100 effluent limits would not be exceeded because operators in the control room would be alerted by radiation monitoring of the effluent stream and loss of level in the reactor vessel and spent fuel pool surge tanks. Operators would be able to isolate the leak or, in the worst case, start the booster pumps, changing the differential pressure across the RHR heat exchanger tubes to terminate leakage into the service water system.

During a review of the engineering analysis for the shutdown condition, the licensee engineering and quality assurance personnel identified that: (1) the radiation monitor at the outfall was not controlled during shutdown conditions to ensure it was operable at all times while the booster pumps were windmilling, (2) the booster pumps were not explicitly controlled during shutdown conditions to be available within a short time in the event of a RHR heat exchanger tube leak, (3) although 10 CFR 100 limits would not be exceeded, the limits of 10 CFR 20 may be exceeded during a design basis RHR heat exchanger tube leak, and (4) other specific operational requirements were not administratively controlled to ensure design basis requirements were met.

The licensee changed procedural requirements to address the need to verify operability of the radiation monitor at the service water discharge to ensure a service water booster pump could be returned to service within 30 minutes and to emphasize to engineers that the requirements of 10 CFR 20 should be considered in addition to 10 CFR Part 100 release limits. Additionally, the licensee corrective action will review several license submittals involving assumed operational conditions to identify whether the detailed assumptions of the design basis and licensing basis are administratively controlled.

This concern is of low safety significance since the loss of inventory due to an RHR heat exchanger tube leak would be apparent to the operators due to alarms in the control room, and the current and past source term of the spent fuel pool is insignificant compared to the design basis source term. The licensee's action to identify and resolve the problems associated with shutdown condition windmilling indicates good problem identification and resolution, as well as strong quality assurance involvement and questioning attitude.

6 PLANT SUPPORT ACTIVITIES (71750)

6.1 Discovery of Contamination of Protective Clothing from Offsite

The licensee identified personnel contamination which was inconsistent with expected radionuclides for the plant. Since the licensee has not had fuel leaks, and the radionuclides found were indicative of fuel leakage products, the licensee suspected the contamination was brought in from offsite. Based on the locations of the contamination, the licensee suspected the vendor providing laundry services for the protective clothing may not be adequately removing contamination and may be mixing the laundry with that from other sites.

The licensee surveyed a sample of coveralls recently delivered to the site. Fourteen of the coveralls indicated about 1,600 cpm above background and about 50,000 dpm contamination. However, isotopic analysis revealed that the contamination was primarily cobalt, rather than fission products. This conclusively indicated that the laundry vendor was not removing contamination adequately, although fuel products were not identified in the survey. Corrective action by the laundry vendor to ensure future shipments have adequate contamination removal, and separation of the licensee's laundry from other laundry from other sources, appears to have resolved the concern. The action taken by the licensee was prompt and appropriate.

6.2 Improper Shipment of Radioactive Materials

On October 26, 1995, the licensee received a shipment of a bracket to be used for core shroud inspection. This object was shipped in a 55 gallon drum but was not labeled as containing radioactive materials since it should have met 40 CFR 173.421 criteria for a limited quantity shipment.

According to 40 CFR 173.421, radiation levels at any point on the surface are not to exceed 0.5 millirem per hour. When this drum was surveyed using two separate instruments, maximum surface radiation levels were approximately 2 millirem per hour. There was no contamination detected.

The licensee notified the shipper. The shipper (Hake Associates) believes that the bracket may have shifted inside the drum, allowing it to be closer to the drum surface, increasing radiation levels. This was found to be the case when the drum was opened. The vendor will use photos of the as-found orientation of the bracket in their investigation of the event. The identification of the inappropriate shipment was an example of good radiological practices.

6.3 Security Lighting Deficiencies

On November 1, 1995, while the inspector was conducting a plant tour, three areas inside the protected area were noted where the light was insufficient to meet the lighting requirements in the security plan. The inspector discussed this concern with the security shift supervisor. According to the security shift supervisor, one area was on the security log, but there was no work document to correct this problem. The second area was also on the security log and a work request had been issued on February 22, 1995, to correct the lighting deficiency in that area. Because the work request was given a low priority, it has not been performed. The third area had not been identified by security. To compensate for the two known deficiencies, the security shift supervisor informed the inspectors that a security officer had been continuously performing rounds of the protected area since the time the deficiencies were identified by the licensee. As soon as the security officer completed one round, the next round was immediately begun. The compensatory actions that security performed alleviated the inspectors' concern. All three areas where lighting was deficient were within the scope of the security patrols' rounds. At the end of the inspection period, the security supervisor was developing corrective actions to heighten the security officers' awareness of identifying lighting deficiencies. This corrective action appeared appropriate.

7 SURVEILLANCE OBSERVATIONS (61726)

7.1 Core Spray Local Leak Rate Testing (LLRT)

On October 18, 1995, the inspector observed LLRT of Core Spray A valves. The test crew appeared knowledgeable and observed procedural requirements in a step by step fashion. The crew was very familiar with the operation of the LLRT test equipment. The crew promptly identified problems as they occurred during testing. No concerns were identified.

8 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

8.1 (Closed) Violation 298/93202-02: Licensee Failed to enter Technical Specification (TS) Action Statement

The performance of MWR 92-0185 caused both suppression chamber/torus water level instrument channels to be inoperable. The licensee failed to recognize that they were included in TS Table 3.2.F, Action Statement E, which required that, if both channels were inoperable, the channels must be restored within

6 hours or, otherwise, an orderly shutdown be initiated and the reactor shall be in hot shutdown in 6 hours and in cold shutdown within the following 18 hours. The water level instruments were not declared operable until 28.5 hours after the time the shift supervisor signed the work package to perform the maintenance.

The inspector verified that training was conducted for licensed operators on TS Sections 3.1 and 3.2, by reviewing the lesson plan and the attendance list. The lesson plan covered the instruments listed in the TS sections and the action statements for these TS. Also, procedural guidelines were developed to prevent the inclusion of multiple TS components into a single MWR. The inspector reviewed Procedure 0.40, "Work Control Program," Revision 2, Step 6, and concluded that the guidelines were in place.

9 IN-OFFICE REVIEW OF LERs (90712)

The LER listed below was reviewed by the inspector and was determined to have met the reporting requirement of 10 CFR 50.73, the report contained an adequate assessment of the subject events, the causes appeared accurately identified, corrective actions appeared appropriate to the circumstances, the generic applicability was properly considered, and no further regulatory followup was indicated.

9.1 <u>(Closed) LER 298/95-014: Procedural Error That Could Result in Compromising Secondary Containment Integrity During Accident Conditions</u>

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. Bremer, Acting Operations Manager
J. Dillich, Assistant Site Manager
J. Gausman, Plant Engineering Manager
R. Godley, Nuclear Licensing and Safety Manager
P. Graham, Senior Engineering Manager
M. Hale, Radiological Protection Manager
J. Herron, Plant Manager
R. Jones, Senior Manager Safety Assessment
J. Mueller, Site Manager
R. Sessoms, Division Manager Quality Assurance

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other licensee personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on November 8, 1995. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.