ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-275 50-323
License Nos.:	DPR-80 DPR-82
Report No.:	50-275/99-17 50-323/99-17
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	October 10 through November 13,1999
Inspectors:	D. Proulx, Senior Resident Inspector D. Acker, Resident Inspector C. Clark, Reactor Inspector G. Replogle, Senior Resident Inspector, WNP2 J. Kramer, Resident Inspector, SONGS
Approved By:	L. J. Smith, Chief, Project Branch E

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report No. 50-275/99-17; 50-323/99-17

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report documents inspections performed during a 5-week period by the resident inspectors.

Operations

- On October 17, 1999, operators drained the refueling cavity without venting the pressurizer as required by the refueling procedures. This created a vacuum in the pressurizer, causing water level in the pressurizer to be at the 122 foot level when reactor vessel level was at the 112 foot level. The inspectors considered that a weak procedure, poor turnovers, failure to monitor pressurizer level during the reactor cavity draining, and failure to maintain a status board contributed to the violation. Technical Specification 6.8.1.a requires that refueling procedures be implemented. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The licensee placed this deficiency in their corrective action program as Quality Evaluation Q0012155 and Action Request A0494864 (Section O1.2).

- Once the failure to properly vent the pressurizer was noted, operations personnel used adequate precautions to drain the remaining water from the pressurizer while maintaining reactor water level constant below the level of the vessel flange (Section O1.2).

- The inspectors considered that the operators' response to an apparent loss of reactor coolant system inventory was adequate. However, the inspectors considered the cause of the problem was not immediately understood by the operators because of failure to discuss the affects of reinitiation of a suspended steam generator secondary side fill procedure. The apparent change in inventory resulted from colder steam generator water cooling and contracting the air in the primary side of the steam generator tubes (Section O1.3).

- Plant management provided excellent oversight and guidance prior to experiencing high seas. Management conservatively curtailed Unit 1 to 60 percent power and held Unit 2 at 35 percent power in anticipation of the storm. Nonetheless, kelp and other debris clogged the circulating water pump intake screens and operators manually tripped both units. Prompt and effective operator response ensured that both units were placed in a safe condition despite the loss of condenser cooling (Section O1.5).

- Operators accomplished three startups in a deliberate and conservative manner. Crew briefings were effective and the shift foremen demonstrated good command and control (Section O1.4, O1.6, and O1.7).

Maintenance

- The inspectors observed that integrated safeguards testing was well controlled by the operating crew. All other control room activities were suspended and each section of the procedure was tailboarded prior to performance (Section M1.2).

Engineering

- A violation of Technical Specification 6.8.4.f was identified for four failures in 1989 and 1990 to control the position of the polar cranes such that jet impingement from a postulated pipe rupture was precluded. The licensee had previously interpreted Technical Specification 6.8.4.f to only apply to the location in which the polar cranes were permanently parked, which allowed for polar crane passage through jet impingement zones. Following discussions with the NRC in 1998 concerning operation of the polar cranes, the licensee identified the violation. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This item was placed in the corrective action program in Quality Evaluation Q0012049 (Section E8.1).

Plant Support

- The inspectors identified boric acid residue on six valves which were slightly contaminated. The licensee took prompt corrective action to post and contain the spread of contamination and issued Action Request A0497375 to evaluate the policy for posting and cleanup of dry boric acid residue (Section R1.2).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. Unit 1 continued to operate at essentially 100 percent power until October 28, when it was ramped to 60 percent power in anticipation of kelp intrusion because of the first large Pacific storm of the season. Later on October 28, operators manually tripped Unit 1 because of impending loss of condenser cooling. Unit 1 stayed in Mode 3 until October 30, when it returned to Mode 1. Unit 1 returned to 100 percent power on November 1 and continued to operate at 100 percent power through the end of the inspection period.

Unit 2 was defueled at the beginning of this inspection period in Refueling Outage 2R9. On October 15, 1999, Unit 2 entered Mode 6 (refueling) at the commencement of core reload. Following core reload, Unit 2 entered Mode 5 (cold shutdown) on October 21 when the reactor head was tensioned. Following completion of outage maintenance work, operators commenced heatup of the reactor coolant system, such that Mode 4 (Hot Shutdown) was entered on October 24. As heatup continued, Unit 2 entered Mode 3 (Hot Standby). With the plant at normal operating temperature and pressure, operators commenced reactor startup and Unit 2 entered Mode 2 (Startup) on October 26. On October 27, Unit 2 entered Mode 1 (Power Operation) and the main generator was subsequently synchronized to the grid. This ended Refueling Outage 2R9. On October 28, the operators manually tripped the unit from 35 percent power because of impending loss of condenser cooling caused by the kelp intrusion. Unit 2 stayed in Mode 3 until October 31, when it entered Modes 2 and 1. Unit 2 completed physics testing and began operation at 100 percent power on November 5. Unit 2 continued to operate at essentially 100 percent power through the end of this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors visited the control room and toured the plant on a frequent basis when on site, including periodic backshift inspections. In general, the performance of plant operators reflected a focus on safety. Operator performance was generally characterized by self- and peer-checking. The utilization of three-way communications continued to improve and was noted to be used extensively during the three startups and dual unit trip discussed below.

O1.2 Draining Reactor Cavity Without a Pressurizer Vent Path (Unit 2)

a. Inspection Scope (71707)

On October 17, 1999, operators drained the reactor cavity and the upper part of the reactor vessel to a level below the reactor vessel flange. After this draining was completed, operators noted pressurizer cold calibration level was reading 11 percent when it should have been reading zero. Operators discovered that they had drained the pressurizer without a pressurizer vent path, which had created a vacuum in the pressurizer without a pressurizer vent path, which had created a vacuum in the pressurizer. The inspectors observed recovery actions and investigated the root cause of this occurrence.

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

After all the fuel had been loaded, operators commenced Operating Procedure OP B-2:VI, "RHR - Draining the Refueling Cavity," Revision 12, to drain the water from the reactor cavity to below the reactor vessel flange, in preparation for head reinstallation. Operators drained the reactor cavity from the 138 foot level to the 112 foot level, which was 2 feet below the reactor vessel flange and approximately 4 feet above the top of the hot leg, in preparation for head installation. At the start of the evolution, the pressurizer cold calibrated level was approximately 50 percent.

After water level was stabilized at 112 feet and the reactor head was set in place, an operator noticed that the cold calibrated pressurizer level was indicating 11 percent water level in the pressurizer. The 11 percent reading on the pressurizer indicated that the water level in the pressurizer was at about 122 feet when reactor vessel level was at 112 feet. With reactor vessel level at 118 feet or lower, the pressurizer level should have indicated zero percent. Operators determined that during draining of the reactor cavity the pressurizer had not been vented. Operators concluded that the pressurizer still contained water because of drawing a vacuum in the pressurizer.

b1 <u>Recovery Actions</u>

Operations personnel developed a procedure for very slowly venting the pressurizer while maintaining reactor water level at 112 feet. Operators slightly increased letdown flow after cracking open a small pressurizer vent path and successfully drained the pressurizer while maintaining the required reactor vessel water level.

b2 <u>Followup Actions</u>

The inspectors and the licensee investigated the cause of this problem. The licensee identified that the control room operator had initialed Step 6.4.6 of Procedure OP B-2 VI for Unit 2, indicating that a pressurizer vent path had been established and that the valve line-up in Attachment 9.7, Operating Procedure OP A-2:II, "Reactor Vessel - Draining the RCS to the Vessel Flange - With Fuel in the Vessel," had been completed.

The control room operator stated that he initialed this step based on verbal confirmation from the shift foreman that the vent path existed. The licensee's preliminary root cause investigation identified that the shift foreman gave the control room operator incorrect information because he believed that Operating Procedure OP A-2:II, Attachment 9.7, a valve line-up, included a pressurizer vent path, but it did not. The shift foreman verified that Attachment 9.7 had been completed; however, the shift foreman did not verify that this condition included a pressurizer vent path.

The licensee identified that personnel who knew the status of the pressurizer vent valves were off shift for rotation. The licensee also identified that control room personnel failed to adequately monitor pressurizer level during the draining of the reactor cavity. The licensee's preliminary conclusion was that failure to vent the pressurizer was caused by personnel error and was contributed to by a weak procedure, inadequate monitoring of pressurizer level during the cavity draining, and poor turnover of the status of the pressurizer related vent valves.

The inspectors agreed with the licensee's findings and had the following additional observation. The inspectors observed that the Reactor Vessel Remote Level Indicating System Status Board, required by Operating Procedure OP L-6, was maintained in the control room. However, the inspectors observed that the position of all the valves shown on this board was not maintained, including the pressurizer power-operated and associated block valves which were all shown as open when they were all closed during the cavity drain. Operations personnel informed the inspectors that valve positions which were normally indicated on the main control board were not routinely maintained on the status board. The inspectors also observed that valves for reactor water level detector isolation were shown on the status board as closed when the detectors were credited with being in operation. The inspectors asked operations management why the status of these valves were incorrectly shown on the status board. Operations management personnel stated that these valves were under the control of maintenance personnel and, therefore, were not maintained on the status board. The inspectors considered that a partially maintained status board would contribute to operator errors instead of aiding the operators' understanding of current plant status. Since this status board indicated that the pressurizer power-operated relief valves and associated block valves were open at the time the pressurizer was drained without a vent path, the inspectors considered that the failure to maintain this status board contributed to the error.

The inspectors considered that the failure to provide a vent path, as required by Step 6.4.6 of Operating Procedure OP B-2 VI, was a violation of Technical Specification 6.8.1.a. Technical Specification 6.8.1.a requires that procedures of Appendix A of Regulatory Guide 1.33, "Quality Assurance Program Requirements," be implemented. Regulatory Guide 1.33, Appendix A, includes procedures for refueling operations. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The licensee placed this deficiency in their corrective action program as Quality Evaluation Q0012155 and Action Request A0494864 (323/99017-02).

c. <u>Conclusions</u>

On October 17, 1999, operators drained the refueling cavity without venting the pressurizer as required by the refueling procedures. This created a vacuum in the pressurizer, causing water level in the pressurizer to be at the 122 foot level when reactor vessel level was at the 112 foot level. The inspectors considered that a weak procedure, poor turnovers, failure to monitor pressurizer level during the reactor cavity draining, and failure to maintain a status board contributed to the violation. Technical Specification 6.8.1.a requires that refueling procedures be implemented. This Severity Level IV violation is being treated as a noncited violation, consistent with

Section VII.B.1.a of the NRC Enforcement Policy. The licensee placed this deficiency in their corrective action program as Quality Evaluation Q0012155 and Action Request A0494864.

Once the failure to properly vent the pressurizer was noted, operations personnel used adequate precautions to drain the remaining water from the pressurizer while maintaining reactor water level constant below the level of the vessel flange.

O1.3 Apparent Loss of Reactor Coolant System Inventory (Unit 2)

a. Inspection Scope (71707)

With Unit 2 in Mode 5, the Operations Director informed the inspectors that there was an apparent reactor coolant system leak of 35 gallons a minute. The inspectors observed operator response to the apparent leak.

b. Observations and Findings

On October 20, 1999, with reactor vessel water level at 112 feet (4 feet above the top of the hot leg) operators observed that charging flow was required to be 35 gallons per minute higher than letdown flow to maintain the water level. Operators also observed an increase in pressurizer relief tank water level. Operators suspected a leak and initiated containment inspections for open or mispositioned valves. No leakage paths were discovered. After approximately 30 minutes, the leak stopped and subsequently reversed, such that letdown flow greater than charging flow was required to maintain the same water level in the reactor vessel.

Operators determined that the increase in pressurizer relief tank water level was being caused by backflow from the reactor coolant drain tank. The reactor coolant drain tank had overfilled because of loss of air to the outlet valve which failed shut. In addition, the level indicator for the reactor coolant drain tank was not functioning properly. Operators determined that the apparent loss of reactor inventory was caused by filling the secondary side of a steam generator with water 40 degrees cooler than the reactor coolant system temperature. As the air trapped in the primary side of the steam generator tubes cooled and contracted, water was drawn into the tubes, causing the apparent loss of inventory.

The procedure for filling the secondary side of the steam generator required that the control room staff be informed of the operation and of the potential for affecting reactor vessel water level. However, the procedure for filling the steam generator had been started early in the morning, then quickly suspended for integrated safeguards testing. Later in the afternoon, when the fill was reinitiated, the information concerning the potential affect on reactor vessel water level was not repeated or discussed among the current operating crew.

The inspectors concluded that the operating crew responded properly to the apparent loss of reactor coolant inventory by initiating actions to determine the cause and reverifying the methods available for maintaining reactor vessel inventory and temperature. However, the inspectors considered that reinitiation of the fill of the secondary side of the steam generator without a discussion of the affects of this action was a poor work practice.

c. Conclusions

The inspectors considered that the operators' response to an apparent loss of reactor coolant system inventory was adequate. However, the inspectors considered the cause of the problem was not immediately understood by the operators because of failure to discuss the affects of reinitiation of a suspended steam generator fill procedure. The apparent change in inventory resulted from colder steam generator water cooling and contracting the air in the primary side of the steam generator tubes.

O1.4 Reactor Startup (Unit 2)

a. Inspection Scope (71707)

The inspectors observed the reactor startup to criticality on October 26, 1999.

b. Observations and Findings

The startup was conducted in a deliberate and well focused manner. Crew briefs were very good and were effective in preparing the crew. The shift foreman demonstrated good command and control.

During the startup, while attempting to move Shutdown Bank B from the full in position, operators received an unexpected "Rod Out of Sequence" alarm. The alarm indicated that Shutdown Bank B was moved from the full in position when Shutdown Bank A was not in the full out position, an illegal operation. Operators promptly stopped and investigated the alarm.

Operators found that the alarm was erroneously generated because the new full out position (225) was not updated in the process computer. The full out position was changed from 228 to 225 this past outage. When Control Rod Bank A was moved to 225 (the full out position), the process computer indicated that the bank was less than full out. Therefore, when Control Rod Bank B was moved, the alarm was generated. Operators promptly updated the computer and continued with the startup. The licensee initiated Action Request A0496226 to address this problem.

c. Conclusions

Operators accomplished the Unit 2 startup in a deliberate and conservative manner. Crew briefings were effective and the shift foreman demonstrated good command and control.

O1.5 Dual Unit Trip (Units 1 and 2)

a. Inspection Scope (71707)

The inspector observed the licensee's preparation for storms and high seas and also observed the operating crew's response during the subsequent dual unit trip.

b. Observations and Findings

High seas have historically been a problem for the Diablo Canyon units. At the beginning of the traditional storm season (midautumn), rough seas can stir up debris on the sea floor and dislodge kelp. The debris and kelp have clogged the intake screens for the circulating water pumps and, ultimately, caused plant trips. On October 28, the licensee was alerted of potential high seas, which had previously challenged plant operations, because of loss of condenser cooling.

Plant management provided excellent oversight and guidance prior to the high seas condition. They reviewed prior history and specified plant conditions that were most likely to result in successful plant operation during sea swells. The licensee reduced Unit 1 power to 60 percent and limited the Unit 2 power ascension to 35 percent.

In spite of the licensee's precautionary measures, at approximately 1 p.m., the differential pressure across the Unit 2 intake screens was excessive (because of debris clogging) and operators manually tripped the unit. A few minutes later, Unit 1 experienced the same problem and was also tripped. All circulating water pumps had to be tripped because of the clogged intake screens. The debris did not affect safety-related auxiliary saltwater pump screens.

Control room operators responded well to the challenge of maintaining both tripped units in a safe condition without condenser cooling available. Both shift foremen demonstrated good command and control and were not distracted by activities on the other units. The plants responded as designed and operators placed the units in a safe condition in a timely manner. The dual unit trip was reported to the NRC consistent with the requirements of 10 CFR 50.72.

c. Conclusions

Plant management provided excellent oversight and guidance prior to experiencing high seas. Management conservatively curtailed Unit 1 to 60 percent power and held Unit 2 at 35 percent power in anticipation of the storm. Nonetheless, kelp and other debris clogged the circulating water pump intake screens and operators manually tripped both units. Prompt and effective operator response ensured that both units were placed in a safe condition despite the loss of condenser cooling.

O1.6 Reactor Startup (Unit 1) (71707)

The inspectors observed the reactor startup to criticality on October 30, 1999. The startup was conducted in a deliberate and well focused manner. Crew briefs were very good and were effective in preparing the crew. The shift foreman demonstrated good command and control.

O1.7 Reactor Startup (Unit 2) (71707)

The inspectors observed the reactor startup to criticality on October 31, 1999. The startup was conducted in a deliberate and well focused manner. Crew briefs were very good and were effective in preparing the crew. The shift foreman demonstrated good command and control.

O8 Miscellaneous Operations Issues (92700, 92901)

O8.1 (Closed) Licensee Event Report (LER) 275/1999-006-00: Reactor trip because of lightning strike.

On September 22, 1999, Unit 1 experienced a full load rejection and reactor trip because of a lightning strike in the 500 kV offsite power system. The lightning strike actuated an overvoltage relay which opened the main generator output breakers, resulting in the load rejection.

The inspectors performed significant followup and evaluation of this event in a previous inspection, as documented in NRC Inspection Report 50-275; 323/99-14. The inspectors noted that this LER satisfactorily described the event and operator response, such that no further followup was necessary.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed portions of work activities covered by the following work orders:

R0180986 Component Cooling Water Heat Exchanger 2-1, Clean and Inspect Tubes/Coatings

C0160612 Component Cooling Water Heat Exchanger 2-1, Remove and Install Expansion Joint for Flange Repairs

C0164674 MS-1-FCV-243 Disassembly, Inspect and Repair Feedwater Pump Turbine 1-2 Low Pressure Stop Valve

M0020400-01 Feedwater Pump 2-1, Repair Low Pressure Steam Chest (Gland) Leak

M0020393-01 Investigate and Correct FCV-242A Oil Leak

b. Observations and Findings

The inspectors considered the work was performed as required by the procedures.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed performance of all or portions of the following surveillance test procedures (STP):

STP M-9G Diesel Generator 24-Hour Load Test and Hot Restart, Revision 32

STP M-15 Integrated Test of Engineering Safeguards and Diesel Generators, Revision 33

STP V-2P1 Exercising Accumulator Isolation Valves, Revision 3A

STP V-2P Exercising Accumulator Check Valve Leak Test Valves and Reactor Vessel Flange Leak Off Valve, Revision 5A

b. Observations and Findings

The inspectors considered the work was performed as required by the procedures. The inspectors observed that STP M-15 was well controlled by the operating crew. All other control room activities were suspended and each section of the procedure was tailboarded prior to performance. The system engineer assisted in the procedure performance.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Containment Closing (Unit 2) (62707)

After refueling, the inspectors observed containment cleaning and inspected the entire containment prior to containment closing. The inspectors did not observe any loose material which could clog the containment recirculation sump screens during an accident. The inspectors did not observe any material condition problems within the containment. The inspectors concluded that the Unit 2 containment cleanup after the refueling was satisfactory.

III. Engineering

E8 Miscellaneous Engineering Issues (92700)

E8.1 (Closed) LER 275; 323/1998-007-00: Technical Specification 6.8.4.f not met because of polar crane operation in jet impingement zones because of a nonconservative interpretation.

On June 24, 1998, the licensee discovered that, in 1989 and 1990, the polar cranes of both units had passed through jet impingement zones in a prohibited operational mode. In 1989, the licensee had interpreted Technical Specification 6.8.4.f to mean that the polar crane could not be permanently parked in a jet impingement zone. Per discussions with the NRC Office of Nuclear Reactor Regulation in 1998, this interpretation was deemed incorrect.

Technical Specification 6.8.4.f states, in part, that the licensee shall establish, implement, and maintain a program that ensures that the position of the polar cranes will preclude jet impingement from a postulated pipe rupture. This program includes training of personnel and procedures for polar crane operation. Administrative Procedure MAI.ID14, "Plant Crane Operating Restrictions," Section 6.5, partially implemented this requirement, and directed the locations in which the polar crane could not be parked. Because the procedure and Technical Specification 6.8.4.f did not specifically prohibit passing the polar crane through a jet impingement zone, in 1989, the licensee issued a Technical Specification interpretation that allowed passing the polar cranes through jet impingement zones as long as the polar crane was not parked in the new location.

On four occasions, in 1989 and 1990, the licensee implemented the above Technical Specification interpretation. These four failures to control the position of the polar cranes such that jet impingement from a postulated pipe rupture was precluded constitute a violation of Technical Specification 6.8.4.f. However, this Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This item was placed in the corrective action program in Quality Evaluation Q0012049 and Action Requests A0462991 and A0463095 (275; 323/99017-02).

The licensee reviewed their high energy line break analyses to ensure that no other potential jet impingement deficiencies existed. The inspectors considered that the licensee's corrective actions were appropriate to the circumstances.

E8.2 (Closed LER 275; 323/1998-011-01): Emergency core cooling system outside design basis because of gas voiding in the suction piping.

This issue was extensively reviewed and determined to be a noncited violation in NRC Inspection Report 50-275;323/99-07. The information in Revision 1 of the LER was considered as part of this inspection report.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

The inspectors evaluated radiation protection practices during plant tours and work observation. The inspectors determined that personnel donned protective clothing and dosimetry properly and that radiological barriers were properly posted.

R1.2 Contamination Control (Unit 2)

a. Inspection Scope (71750)

The inspectors performed routine walkdowns of the plant and identified boric acid residue on numerous valves. The inspectors discussed the observations with radiation protection technicians and supervisors.

b. Observations and Findings

On November 2, 1999, the inspectors observed several valves with boric acid residue. The valves included: Valves CVCS-2-8369A, B, C, and D, "RCP [Reactor Coolant Pump] Seal Water Injection;" Valve SI-2-38, "Safety Injection to Hot Leg 1 and 2 Test Connection;" Valve SI-2-8890A, "Pressure Balancing Valve for 2-8802A;" and Valve SI-2-34, "Safety Injection to Hot Leg 1 and 2 Line Vent." The inspectors informed radiation protection personnel about the observations. A radiation protection technician surveyed the valves for contamination and found that Valve CVCS-2-8369D had a contamination level of 10,000 counts per minute and four of the remaining five valves had contamination levels between 100 and 1000 counts per minute. The technician installed drip catches under the six valves with contamination.

On November 3, the inspectors performed a walkdown of the valve area and observed that the drip catches were installed under the five contaminated areas. In addition, the inspectors observed that the licensee had initiated decontamination of the seal water injection valves. The control room operators were unaware of the decontamination efforts.

At 10:30 a.m. on November 3, the control room operators entered Technical Specification 3.4.6.2 (a 4-hour shutdown action statement) because of controlled leakage for an unknown reason. The control room operator noted that Reactor Coolant Pump 2-1 seal injection flow had increased from 9 to 12 gallons per minute for no apparent reason. The operators informed the system engineer about the observation and ultimately the operators learned that the valve had been decontaminated and could have been bumped. The operators adjusted the Reactor Coolant Pump 2-1 seal injection valve, verified that all the reactor coolant pumps had satisfactory seal injection flow, and exited the action statement at 12:10 p.m. The licensee initiated Action Request A0496924 to document and evaluate the event for corrective actions.

The inspectors discussed the findings with a radiation protection supervisor and the system engineer. The radiation protection supervisor indicated that general surveys of the area containing the valves were performed daily and detailed surveys were performed weekly. The system engineer stated that monthly walkdowns of the area were normally performed; however, the previous month's walkdown was not performed because of refueling outage activities. The Radiation Protection Manager stated that the presence of dry boric acid residues did not, by itself, require that the residue area be posted as a contaminated area. In addition, the Radiation Protection Manager stated that small dry boric acid residue was not normally cleaned until after the system engineer walkdowns, to allow the system engineers to evaluate small leaks. The inspectors observed that this practice could allow contaminated areas to not be properly posted for some time. The licensee issued Action Request A0497375 to evaluate the policy regarding when to post and clean up dry boric acid residue.

c. Conclusions

The inspectors identified boric acid residue on six valves which were slightly contaminated. The licensee took prompt corrective action to post and contain the spread of contamination and issued Action Request A0497375 to evaluate the policy for posting and cleanup of dry boric acid residue.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 12, 1999. The licensee acknowledged the findings presented.

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

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. R. Becker, Manager, Operations Services
W. G. Crockett, Manager, Nuclear Quality Services
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R. A. Waltos, Manager, Maintenance Services
L. F. Womack, Vice President, Nuclear Technical Services

INSPECTION PROCEDURES (IP) USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Operations Followup

ITEMS OPENED AND CLOSED

Opened

None.

Closed

275/1999-006-00	LER	Reactor trip because of lightning strike (Section O8.1)
275; 323/ 1998-007-00	LER	Technical Specification 6.8.4.f not met because of polar crane operation in jet impingement zones (Section E8.1)
275; 323/ 1998-011-01	LER	Emergency core cooling system outside design basis because of gas voiding in the suction piping (Section E8.2)

Opened and Closed

323/99017-01	NCV	Failure to vent pressurizer as required by refueling procedures (Section O1.2)
275; 323/99017-02	NCV	Technical Specification 6.8.4.f not met because of polar crane operation in jet impingement zones (Section E8.1)