ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License Nos.:	DPR-80 DPR-82
Report No.:	50-275/99-18 50-323/99-18
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:	November 14 through December 25, 1999
Inspectors:	David L. Proulx, Senior Resident Inspector Dyle G. Acker, Resident Inspector David E. Corporandy, Resident Inspector, Palo Verde William M. McNeill, Reactor Inspector
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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report No. 50-275/99-18; 50-323/99-18

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report documents inspection performed during a 6-week period by the resident inspectors.

Operations

- The inspectors concluded that the licensee's action to shut down both units in anticipation of an incoming storm was conservative and focused on safety (Section O1.2).

- Unit 2 operators responded promptly and in accordance with procedures to reduce power to 50 percent following the trip of Circulating Water Pump 2-2. Subsequent efforts to determine and correct the source of the problem, a failed pressure switch, were conducted in a safety conscious manner and were successful in returning the plant to full power (Section O1.3).

- A violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for failure to prevent recurrence of a significant condition adverse to quality. An excessive gas void formed in the emergency core cooling system because the licensee failed to completely fill and vent plant systems following Outage 2R9. This 0.9 cubic foot gas void rendered both of the safety injection pumps or both of the centrifugal charging pumps inoperable for approximately 4 hours while Unit 2 was in Mode 3. This condition existed longer than necessary because enhanced monitoring techniques, used following a previous outage to detect gas voiding, were deemed unnecessary. This event had the same root cause as several similar events (failure to provide an adequate fill and vent of plant systems following outages). The licensee concluded that this event was of low safety and risk significance. 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 as Action Request A0495969 (Section O1.4).

Maintenance

- A violation of Technical Specification 3.6.2.3 was identified for failure of Containment Fan Cooler Units 2-4 and 2-5 in 1998. The licensee identified during an outage that the fan cooler motors had failed due to improperly crimped electrical splices. 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 Action Requests A0461631 and A045964 (Section M8.1).

- A violation of Technical Specification 6.8.1.a was identified for failure to properly install the fuse holder for local operation of a diesel engine generator output breaker. For approximately 7 months, this action rendered the diesel engine generator incapable of performing its intended function for postulated fire scenarios that disabled off-site power and required control room evacuation. However, two other diesel engine generators were available or easily recoverable for local operation to mitigate the consequences of this fire scenario; thus, this event was of low potential safety consequence. The licensee determined that this event was not risk significant. 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 as Action Request A0491213 (Section M8.2).

Engineering

- The inspectors considered that the licensee's planned actions to verify acceptable opening torque switch operation for residual heat removal supply valves was satisfactory (Section E1.1).

- System engineering performed an inadequate operability assessment that did not take into account the Technical Specifications requirements for operability. Hydrogen Recombiner 1-2 was declared operable despite temperature instrumentation being inoperable that was required by Technical Specification 4.6.4.2(b)1. The recombiner was returned to service prior to expiration of the 30-day shutdown action statement (Section E1.2).

- The inspectors considered that the design changes reviewed were adequately accomplished in accordance with control measures similar to those of the original design and were examples of good, thorough engineering work (Section E1.3).

- The inspectors concluded that the licensee had adequately addressed the affect of off-site transmission line changes in site procedures for determination of operability of off-site power (Section E1.4).

Plant Support

- With the exception of a minor contamination event that was immediately corrected, routine radiation protection activities were performed properly (Section R1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On November 19, 1999, operators reduced power and took the unit off-line in anticipation of heavy seas and kelp intrusion. Unit 1 was returned to full power on November 21 and operated at essentially 100 percent power until the end of this inspection period.

Unit 2 began this inspection period at 100 percent power. On November 19, 1999, operators reduced power and took the unit off-line in anticipation of heavy seas and kelp intrusion. Unit 2 was connected to the grid on November 20 and returned to full power on November 21. On December 2, Unit 2 was rapidly ramped to 50 percent power due to problems with a circulating water pump (CWP). Unit 2 returned to full power on December 3 and operated at essentially 100 percent power until 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 back shift inspections. In general, the performance of plant operators reflected a focus on safety. Operator performance was generally characterized by self- and peer-checking. Operators properly tracked entries into limiting conditions for operation action statements and maintained good cognizance of system status.

O1.2 High Swell Warnings

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to weather reports indicating that there would be high ocean swells starting on November 19, 1999.

b. Observations and Findings

The licensee has had a history of the first winter storms bringing in sufficient kelp to clog the CWP intake, requiring tripping of one or both units. The licensee developed a procedure to evaluate incoming storms, kelp conditions, and the availability of intake equipment to determine if it would be prudent to reduce power or shut down both units. The licensee issued Operating Order O-28, "Intake Management," Revision 4A, to provide guidelines for evaluation of each incoming storm.

Prior to the November 19 storm, the Plant Staff Review Committee reviewed the predicted sea swells and the large amount of kelp in the intake area and, even though all intake equipment was operable, determined that the storm could potentially foul the circulating water pump screens, causing loss of reactor heat sink. The licensee took both units off-line during the storm.

The inspectors reviewed the licensee's actions and considered the actions to be in accordance with Operating Order O-28 guidelines. The inspectors considered that the licensee's actions were conservative and focused on safety.

c. Conclusions

The inspectors concluded that the licensee's action to shut down both units in anticipation of an incoming storm was conservative and focused on safety.

O1.3 Rapid Load Reduction because of the Trip of Circulating Water Pump (CWP) 2-2 (Unit 2)

a. Inspection Scope (71707, 93702)

On December, 2, 1999, at 3:56 p.m., Unit 2 CWP 2-2 tripped on low intake cooling water pressure. The operators commenced a rapid load reduction to 50 percent power. The inspectors interviewed personnel and reviewed control room logs and other pertinent documents in order to assess the licensee's evaluation of the event and the operators' response.

b. Observations and Findings

At 3:46 p.m. on December 2, Unit 2 received a CWP 2-2 Cooling Water Low Pressure Alarm. As specified in Alarm Response Procedure AR PK13-12, Revision 2, the operators opened the intake cooler pump crosstie valves (FCV-380 and FCV-381); however, the low pressure alarm did not clear, and no signs of leakage were observed. The nuclear operator stationed at the intake was directed to agitate pressure Switch PS-281, and this action temporarily reset the alarm and timer at 3:51 p.m. However, the alarm immediately reactivated and, as designed, the alarm timer tripped CWP 2-2 after 5 minutes, at 3:56 p.m.

As directed by Procedure AR PK13-12, the operators commenced a rapid load reduction in accordance with Procedure OP AP-25, "Rapid Load Reduction," Revision 3. The operators reduced power at a rate of approximately 200 MW per minute. The inspectors verified that the operators responded promptly and in accordance with the procedure. Plant equipment responses were as anticipated. Once power was stabilized at 50 percent, operations management developed and validated a troubleshooting plan before proceeding.

The troubleshooting revealed that pressure Switch PS-281 had failed. Indicated pressure for the CWP intake cooling water was approximately 40 psig, a pressure within the normal range. PS-281 nominal set pressures should have been approximately 23 psig and 28 psig, respectively, for low pressure alarm/trip and reset. The "as-found" values for low pressure alarm/trip and reset were approximately 32.5 and 55 psig, respectively. The licensee determined that the door of the cabinet which housed pressure Switch PS-281 had been opened and then closed at about the time of the first alarm. The licensee surmised that the pressure switch, which is sensitive to vibration, saw a momentary dip in pressure below 32.5 psig. Although the pressure dip was attributed to the vibration from closing the cabinet door and not an actual pressure dip, once in a tripped state, the 40 psig actual pressure was insufficient to satisfy the 55 psig reset requirement of the out-of-calibration pressure Switch PS-281 and CWP 2-2 was tripped at the end of the timer delay.

By approximately 10 p.m. on December 2, the licensee had replaced failed pressure Switch PS-281 with a properly calibrated switch. Following the replacement, power was increased and full power was achieved the following day.

c. Conclusions

Unit 2 operators responded promptly and in accordance with procedures to reduce power to 50 percent following the trip of Circulating Water Pump 2-2. Subsequent efforts to determine and correct the source of the problem, a failed pressure switch, were conducted in a safety conscious manner and were successful in returning the plant to full power.

O1.4 Emergency Core Cooling System (ECCS) Voiding (Unit 2)

a. Inspection Scope (71707, 92901)

The inspectors evaluated the licensee response to Action Request A0495969, which described an event in which the licensee discovered a void in the ECCS piping.

b. Observations and Findings

b.1 Background

NRC Inspection Report 50-275; 323/99-07 discussed an issue involving voiding in the ECCS. The voids were located in either unit's centrifugal charging or safety injection pump suctions and could be swept into the pumps' suctions, potentially resulting in gas binding and rendering the pumps inoperable. The licensee established an administrative limit of 0.44 cubic feet of void space to determine operability. The inspection report noted that these voids existed on several occasions over a number of years and that the licensee had several missed opportunities to correct this problem. The licensee determined that the root cause of the voiding was inadequate filling and venting of plant systems following outages. In response to NRC Inspection Report 50-275; 323/99-07, the licensee stated that they would evaluate plant systems to determine if adequate venting was being performed and would provide enhanced monitoring of the ECCS pump suctions following outages.

Following Unit 1 Outage 1R9, the licensee implemented enhanced monitoring of the ECCS for void using temporary instrumentation. Operators were provided with a standing order to monitor the temporary instrumentation for voids every 12 hours and upon any changes in plant configuration (e.g., pump starts/stops, valve cycling, system realignments). However, operators were not provided with acceptance criteria so that action could be taken to vent off the gas void. As a result, operators logged out-of-specification data several times over 2 days without recognizing that the void size rendered the ECCS inoperable. For corrective action, the licensee revised the standing order to provide acceptance criterion and action to take in the event of excessive gas voiding in the ECCS.

b.2 <u>Unit 2 ECCS Voids</u>

At the end of Outage 2R9, the licensee performed filling and venting operations in an attempt to prevent existing voids from migrating to the suction of the ECCS pumps. In addition, engineering personnel performed enhanced monitoring using temporary ultrasonic instrumentation to ensure that no gas voids formed in the ECCS. Prior to transitioning to Mode 4 (Hot Shutdown), on October 25, 1999, engineering personnel terminated the enhanced monitoring in the belief that the Unit 2 ECCS had been fully filled and vented. Despite the sudden appearance of a gas void in the Unit 1 ECCS previously when a valve was cycled, the licensee determined that it was unnecessary to implement the standing order for operators to monitor the temporary instrumentation for voids when plant conditions changed.

On October 25, with Unit 2 in Mode 3 (Hot Shutdown) at approximately 9:30 p.m., operators placed the excess letdown heat exchanger in service. This alignment was rarely used (but not unheard of); thus engineering personnel did not anticipate that this alignment could cause existing gas voids to migrate to the chemical and volume control system and, ultimately, to the suction of the ECCS pumps. This section of piping was not fully vented following testing because of several changes in configuration during the outage. Thus, over a 30-minute period, following placing the excess letdown heat exchanger in service, a 0.9 cubic foot gas void developed near Valves 2-8807A and 2-8807B, the isolation valves at the suction of the safety injection and centrifugal charging pumps for the recirculation phase of accident mitigation. Because no enhanced monitoring for gas voids was in place for changing system configurations, this condition went undetected until 12:15 a.m. on October 26.

At 12:15 a.m. on October 26, an inservice inspection engineer (in the area for unrelated work) observed the temporary ultrasonic monitoring device placed on the ECCS suction piping and noted that a .9 cubic foot gas void existed. Because the volume of the gas void exceeded the licensee limit of 0.44 cubic feet, the engineer notified the shift foreman. The shift foreman initiated an entry into Technical Specification 3.0.3 and directed that the ECCS piping be vented. At approximately 12:40 a.m. on October 26, the gas void was removed and operators exited Technical Specification 3.0.3. Action Request A0495969 was initiated to enter this item into the corrective action system.

Licensee investigation revealed that, on September 30, sections of the seal water return line and letdown system were drained to support local leak rate testing. Operators refilled and vented these lines on October 19 and 20. However, because of abnormal configurations in place to support other outage work, the normal vent path was not used, so the lines were not completely vented.

The inspectors noted that several previous instances of excessive gas voiding occurred at the plant, as discussed in NRC Inspection Report 50-275; 323/99-07. The root causes for the October 25, 1999, event were similar to those noted previously. In addition, the gas voids in the ECCS existed longer than necessary because enhanced monitoring techniques, used following a previous outage to detect gas voiding, were deemed unnecessary. Therefore, this event was indicative that corrective actions for previous instances of voiding were not effective.

b.3 Corrective Action Program

Issues of ECCS voiding were treated in the licensee's corrective action process as a significant condition adverse to quality. Procedure OM7.ID1 "Problem Identification and Resolution - Action Requests," Revision 12, Section 7.2, required that conditions that resulted in potential inoperability of multiple trains within a system be treated as significant conditions adverse to quality. Appendix B, Criterion XVI of 10 CFR Part 50 requires, in part, that, for significant conditions adverse to quality, corrective action to prevent recurrence be implemented. Because an additional instance of significant voiding occurred with the same root cause (failure to properly fill and vent plant systems following an outage), the corrective actions to prevent recurrence were not effective. The failure to provide effective corrective action to prevent recurrence for a significant condition adverse to quality (ECCS voiding) is a violation of 10 CFR Part 50 Appendix B, Criterion XVI. 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 Action Request A0495969 (323/99018-01).

b.4 Safety Assessment

The licensee determined that the safety significance of this event was low. Even if both safety injection pumps were rendered inoperable by the gas voids, only one centrifugal charging pump was necessary during the recirculation phase of accident mitigation to ensure that peak cladding temperature was less than 2200°F. The safety significance was further mitigated in that Unit 2 was in Mode 3. The risk significance was also demonstrated to be low in that the condition existed for about 4 hours and sufficient backup systems were available.

c. Conclusions

A violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for failure to prevent recurrence of a significant condition adverse to quality. An excessive gas void formed in the emergency core cooling system because the licensee failed to completely fill and vent plant systems following Outage 2R9. This 0.9 cubic foot gas void rendered both of the safety injection pumps or both of the centrifugal charging pumps inoperable for approximately 4 hours while Unit 2 was in Mode 3. This condition existed longer than necessary because enhanced monitoring techniques, used following a previous outage to detect gas voiding, were deemed unnecessary. This event had the same root cause as several similar events (failure to provide an adequate fill and vent of plant systems following outages). The licensee concluded that this event was of low safety and risk significance. This Severity Level IV violation is being created 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 as Action Request A9495969.

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 and maintenance procedures:

R0178123	Inspect Turbine/Sample Gear Box
R0196788	Sample Turbine Bearing/Governor Oil
R0196789	Sample Auxiliary Feed Pump 2-1 Oil
MPE-67.3A	Maintenance and Overhaul of Exide Station Battery Chargers

b. Observations and Findings

The inspectors observed that the work activities were performed properly.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

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

STP I-4-PCV22	10 Percent Steam Dump Valve PCV-22 Calibration, Revision 3A (Unit 2)
STP I-36-S1R02	Protection Set 1, Rack 2 Channels Operational Test, Revision 3 (Unit 2)
STP 1-2C1	Removal of Power Range Channel from Service, Revision 18 (Unit 2)
STP I-2D	Power Range Incore/Excore Calibration, Revision 43A (Unit 2)

b. Observations and Findings

The inspectors observed that knowledgeable personnel performed these surveillances satisfactorily, in accordance with the applicable procedures.

M8 Miscellaneous Maintenance Issues (92700, 92902)

M8.1 (Closed) Licensee Event Report 323/1998-003-00: Technical Specification 3.6.2.3 not met because of inadequate splice connections on containment fan cooler units because of inadequate procedural guidance.

On April 24, 1998, with Unit 2 shutdown, the licensee identified that Technical Specification 3.6.2.3 had previously not been met during power operation, because of failure of Containment Fan Cooler Units 2-4 and 2-5. With these two fan coolers inoperable, the licensee could not meet the minimum requirements for operable fan coolers. This condition existed for approximately 5 days, while Technical Specification 3.6.2.3 allows less than the minimum operable containment fan cooler units for up to 72 hours.

The licensee determined that both fan coolers had failed electrical splices. The failed splices had been done by licensee personnel in 1991. Electricians had not adequately crimped the splice connections, because of two different size leads. The licensee determined that Containment Fan Cooler Units 2-4 and 2-5 were the only fan coolers that had motor leads spliced by licensee personnel. Vendor personnel had installed all the remaining motor lead splices.

The licensee replaced the subject containment fan cooler unit motors, inspected all other fan cooler motor connections in both units, and added instructions to address splicing leads of different sizes.

The licensee determined that this event was of low safety significance. The design basis accident analysis took credit for only two operable containment fan cooler units. Three Unit 2 containment fan cooler units were operable during the time period Containment Fan Cooler Units 2-4 and 2-5 were inoperable. Therefore, adequate containment heat removal was available.

The inspectors considered that the failure to restore Containment Fan Cooler Units 2-4 and 2-5 to operable status within the Technical Specification time limits was a violation of Technical Specification 3.6.2.3. 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 Action Requests A0461631 and A045964 (323/99018-02).

M8.2 (Closed) Unresolved Item 275/99014-03: improper Installation of Diesel Engine Generator (DEG) 1-2 fuses.

a. Inspection Scope

As discussed in NRC Inspection Report 50-275; 323/99-14, the inspectors evaluated the licensee's response to Action Request A0491213, which discussed an event in which the dc control power fuse holder for local operation of DEG 1-2 was found installed improperly.

b. Observations and Findings

On September 11, 1999, the licensee performed a clearance to support control room light socket testing associated with DEG 1-2. The clearance required operators to place the Local/Remote switch for controlling DEG 1-2 in the "Local" position. When control of DEG 1-2 was transferred to local operation, operators unexpectedly received the annunciator "Loss of DC Control Power" for DEG 1-2. The licensee initiated an action request to enter this item into the corrective action system. Licensee investigation revealed that the control power fuse holder for local operation of the output breaker was installed upside down. Operators installed the fuse holder properly and the annunciator cleared.

Maintenance personnel had not worked in this panel since Refueling Outage 1R9 in February of 1999, indicating that this condition had existed for approximately 7 months. Specifically, the fuse holder had been repositioned upside down, during preventive maintenance that replaced the dc control power fuses for the DEG 1-2 output breaker.

On February 20, 1999, technical maintenance personnel had removed and replaced the dc control power fuses for local operation of the DEG 1-2 output breaker in accordance with Procedure MP E-63.3C, "Maintenance of General Electric Metal-Clad 4 kV and 12 kV Switchgear," Revision 7, paragraph 7.6.2. Because the fuse holder was not properly installed, this procedure step was not adequately implemented. Technical Specification 6.8.1 requires that procedures of Appendix A of Regulatory Guide 1.33, "Quality Assurance Program Requirements," be implemented. Regulatory Guide 1.33, Appendix A included procedures for safety-related maintenance. The failure to properly install the local control power fuse holder for DEG 1-2 in accordance with Procedure MP E-63.3C is a violation of Technical Specification 6.8.1.a. 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 as Action Request A0491213 (275/99018-03).

The licensee performed a preliminary evaluation of the potential safety consequences of the mispositioned fuse holder. The licensee noted that, for design basis accidents, DEG 1-2 was required to start automatically with the Local/Remote switch in the "Remote" position. Therefore, the unavailability of DEG 1-2 with the Local/Remote switch in the "Local" position did not affect plant response to design basis accidents. However, 10 CFR Part 50, Appendix A, General Design Criterion 3, addresses design requirements for fire protection. The licensee's fire protection and safe shutdown analysis credited the ability to start and load each of the DEGs locally. Thus, DEG 1-2 was unavailable for these functions.

The licensee stated that the mispositioned fuses were likely to be easily identified if a DEG failed to start or load locally, mitigating the potential safety consequence. The inspectors disagreed that the mispositioned fuses could be easily discovered. No local annunciation was provided for loss of dc control power. In addition, no procedural guidance existed to check the dc control power fuses.

The inspectors noted that DEGs 1-1 and 1-2 were also inoperable for short periods of time for routine preventive maintenance (e.g., oil samples, engine coolant changes, and testing). However, because the period of unavailability of the other two Unit 1 DEGs for local operation was not significant and the DEGs were recoverable in a short period of time, the inspectors concluded that the licensee could achieve and maintain safe shutdown. The inspectors agreed that this event was of low potential safety consequence.

In addition, the licensee determined that the risk significance of installing the fuse holders for DEG 1-2 improperly was low because of the unlikelihood of a control room fire that would also disable off-site power, and because of the availability of the other two Unit 1 DEGs. The NRC Senior Reactor Analyst reviewed the licensee's risk assessment. While the analyst noted that the licensee calculations were overly optimistic, the analyst agreed that this event was not risk significant.

c. Conclusions

A violation of Technical Specification 6.8.1.a was identified for failure to properly install the fuse holder for local operation of a DEG output breaker. For approximately 7 months, this action rendered the DEG incapable of performing its intended function for postulated fire scenarios that disabled off-site power and required control room evacuation. However, two other DEGs were available or easily recoverable for local operation to mitigate the consequences of this fire scenario; thus, this event was of low potential safety consequence. The licensee determined that this event was not risk significant. 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 as Action Request A0491213.

III. Engineering

E1 Conduct of Engineering

E1.1 Residual Heat Removal Suction Valve Fails to Open During Testing

a. Inspection Scope (37551)

The inspectors evaluated the licensee's response to the failure of Unit 2 residual heat removal suction Valve 8702 to open. Inspectors reviewed Action Request 0491391 to support this inspection.

b. Observations and Findings

Unit 2 Valve 8702 was a residual heat removal suction valve which was in series with Valve 8701. These valves connected the suction side of the residual heat removal pump with a hot leg of the reactor coolant system. On September 27, 1999, Valve 8702 failed to open during stroke-time testing with no differential pressure across the valve. The licensee determined that the valve did not open because the torque switch had been set improperly during the last outage and the setting had not been tested to verify that it was correct.

By design, the valve opening torque switch setting was selected to stop the valve from opening if excessive differential pressure across the valve seat was present. Excessive differential pressure would indicate that the residual heat removal system could be over pressurized. A pressure switch also provided this protective function. Three valves, Unit 2 Valve 8701 and Unit 1 Valves 8701 and 8702, had the same opening torque switch logic and testing requirements and also had not been tested for proper opening torque switch operation.

However, Design Criteria Memorandum S-10, paragraph 4.3.3.3, stated that the motor operation of these valves was not safety related, only the hand operation of the valves was safety related because the motor operators did not meet single failure criteria. The licensee stated that no time constraints existed for opening these valves. The licensee also stated that they planned to amend the torque switch balance procedure and to add verification of opening torque to the test procedure. The licensee reset and retested the opening and closing torque switches on Valve 8702. The inspectors considered that the licensee's evaluation was acceptable.

c. Conclusions

The inspectors considered that the licensee's planned actions to verify acceptable opening torque switch operation for residual heat removal supply valves were satisfactory.

E1.2 Improper Operability Assessment

a. Inspection Scope (37551, 71707)

The inspectors reviewed the operability assessment associated with Action Request A0498569, which addressed the operability of Hydrogen Recombiner 1-2.

b. Observations and Findings

On December 2, 1999, the inspectors identified that the temperature indication for Hydrogen Recombiner 1-2 was not operating properly. The inspectors noted that the temperature indication for the recombiner indicated 750°F and was in the alarm condition. The inspectors determined that this indication was improper in that the recombiner was shut down and had not operated since August 1999. Hydrogen Recombiner 1-1, the opposite train recombiner, indicated 106°F, which the inspectors noted was approximately the containment ambient temperature and was the correct temperature for Hydrogen Recombiner 1-2. The inspectors notified the shift foremen, who initiated an action request to place this item in the corrective action program.

The inspectors noted that the hydrogen recombiners were manually operated systems. During a design basis accident, operators were required to manually initiate the hydrogen recombiners if hydrogen levels reached 0.5 percent in containment. To initiate the recombiner, operators were required to dial in a desired temperature to ensure efficient recombination of hydrogen and oxygen to water and to verify that the proper temperature was maintained. Therefore, temperature indication was an important parameter for proper operation of the recombiner units. In addition, Technical Specification 4.6.4.2.b(1) requires the licensee to perform a channel calibration of all instrumentation and controls associated with operating the recombiner. The inspectors noted that Procedure STP-M88B, "Electric Hydrogen Recombiner EHRS 1-2 Temperature Channel Calibration," Revision 8, included the temperature indication and high temperature alarm as part of the instrumentation required for operability and stated that performance of Procedure STP-M88B was required to satisfy Technical Specification 4.6.4.2b.(1). Therefore, the inspectors determined that the as-found condition rendered Hydrogen Recombiner 1-2 inoperable. The shift foreman initially agreed with the inspectors comments and declared the unit inoperable.

However, on December 3, to confirm this assessment, the shift foreman contacted the system engineer to perform a prompt operability assessment. The system engineer noted that proper operation of the recombiner could be confirmed by a decrease in containment hydrogen concentration or proper indication on the installed wattmeter. Therefore, because of alternate means of indication, the system engineer documented on the prompt operability assessment that Hydrogen Recombiner 1-2 was operable. Operators reviewed this assessment and did not question the conclusions. Operators declared the unit operable and cleared the Technical Specifications limiting condition for operation tracking entry.

The inspectors reviewed the operability assessment. The inspectors noted that Technical Specification 4.0.3 states that noncompliance with a surveillance requirement shall constitute inoperability of the associated equipment. Because the temperature meter was not indicating properly, the required instrumentation of Technical Specification 4.6.4.2.(b)1 was not in calibration. Therefore, the inspectors informed the system engineer that the hydrogen recombiner should be considered inoperable. Based on the inspectors' concerns, the system engineer contacted regulatory services personnel for additional evaluation. On December 8, the regulatory services engineer performed further assessment of the condition and determined that the hydrogen recombiner was inoperable since December 2, because the Technical Specification surveillance requirement could not be met. Operators subsequently reinitiated the Technical Specifications tracking entry, which allowed 30 days to return the unit to service before shutting down. On December 15, technical maintenance personnel replaced and calibrated the temperature indicating unit for Hydrogen Recombiner 1-2. Operators declared the repaired system operable, well within the 30-day limiting condition for operation action statement.

c. Conclusions

System engineering performed an inadequate operability assessment that did not take into account the Technical Specifications requirements for operability. Hydrogen Recombiner 1-2 was declared operable despite temperature instrumentation that was required by Technical Specification 4.6.4.2(b)1 being inoperable. The recombiner was returned to service prior to expiration of the 30-day shutdown action statement.

E1.3 Review of Recent Design Changes

a. Inspection Scope (37551)

The inspectors reviewed portions of the following design change packages (DCPs) implemented during the recent Unit 2 refueling outage:

DCP P-48376	"Add SI-2-8804B Vent Valve"
DCP N-50486	"ECCS Pump Crosstie Piping - Add High Point Vent"
DCP N-50348	"CCP 22 - Replace Installed Pump with Spare"

b. Observation and Findings

The inspectors interviewed cognizant plant personnel and reviewed pertinent documents. The inspection focused primarily on verifying that design changes were subject to design control measures commensurate with those applied to the original design, including, in particular, calculations and postmodification testing. No significant issues were identified.

c. Conclusions

The inspectors considered that the design changes reviewed were adequately accomplished in accordance with control measures similar to those of the original design and were examples of good, thorough engineering work.

E1.4 Modification of Off-site Power Lines

a. Inspection Scope (37551)

The inspectors reviewed the licensee's analysis of changes to 230 kV off-site power lines which supply power to the startup transformers.

b. Observation and Findings

The inspectors observed that the licensee was adding a switchyard to one of the 230 kV lines that supply power to the site. The inspectors reviewed site procedures to determine whether the new design was incorporated. The inspectors determined that the new design was adequately addressed in site procedures for determination of operability of off-site power.

The inspectors observed that the licensee's guidelines for determining the operability of off-site power was an informal procedure, O-23, "Operating Instructions for Reliable Transmission Service for Diablo Canyon Power Plant." The inspectors considered that this procedure contained adequate guidelines for determination of operability of off-site power based on a number of combinations of power lines in service and operating voltages. However, the inspectors observed that Procedure O-23 also contained instructions for blocking transfer of CWPs from unit auxiliary to startup power under degraded voltage conditions. The inspectors considered that since Procedure O-23 was not a procedure covered by the licensee's quality assurance program, that it should not be used to direct plant operations. The inspectors discussed Procedure O-23 with the licensee. The licensee stated that control room actions were not taken in accordance with Procedure O-23, but agreed that this was not clear from reading Procedure O-23. The licensee issued Operating Procedure J-2:VIII, Revision 1, "Guidelines for Reliable Transmission Services for DCPP," to formalize in a quality-related document site actions associated with off-site power. The inspectors considered the licensee's actions satisfactory.

c. Conclusions

The inspectors concluded that the licensee had adequately addressed the affect of off-site transmission line changes in site procedures for determination of operability of off-site power.

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 observed in the Unit 2 penetration area that boric acid was dripping onto the floor from the overhead and was intermixing with lagging debris. The inspectors considered that personnel working the area could become contaminated. The inspectors notified radiological protection technicians. The licensee swiped the floor, found low levels of contamination (2000 counts per minute), cleaned the area, identified that Valve CVCS-2-276 had a slow leak, and installed a catch. The inspector considered the licensee's actions to be adequate.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours, the inspectors noted that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the Primary Access Point were performed well. During back shift inspections, the inspectors noted that the protected area was properly illuminated, especially in areas where temporary equipment was brought in.

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 December 30, 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
R. D. Gray, Director, Radiation Protection
T. L. Grebel, Director, Regulatory Services
D. B. Miklush, Manager, Engineering Services
D. H. Oatley, Vice President and Plant Manager
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	Followup - Operations
IP 92902	Followup - Maintenance
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

None

Closed

323/1998-003-00	LER	Technical Specification 3.6.2.3 not met because of inadequate splice connections on containment fan cooler units because of inadequate procedural guidance (Section M8.1)
275/99014-03	URI	Improper installation of DEG 1-2 fuses (Section M8.2)

Opened and Closed

323/99018-01	NCV	Inadequate corrective actions for ECCS voiding (Section O1.4)
323/99018-02	NCV	Technical Specification 3.6.2.3 not met because of inadequate splice connections on containment fan cooler units because of inadequate procedural guidance (Section M8.1)
275/99018-03	NCV	Improper installation of DEG 1-2 fuses (Section M8.2)

LIST OF ACRONYMS USED

CWP	circulating water pump
ECCS	emergency core cooling system
DCP	design change package
DEG	diesel engine generator
IP	inspection procedure
LER	licensee event report
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
PDR	Public Document Room
STP	surveillance test procedure
URI	unresolved item