ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License Nos.:	DPR-80 DPR-82
Report No.:	50-275/98-20 50-323/98-20
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:	December 6, 1998, through January 23, 1999
Inspectors:	D. L. Proulx, Senior Resident Inspector D. G. Acker, Resident Inspector I. A. Barnes, Technical Assistant, Division of Reactor Safety (DRS) C. A. Clark, Reactor Inspector, Engineering and Maintenance Branch, DRS
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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report 50-275/98-20; 50-323/98-20

This inspection included aspects of licensee operations, maintenance, engineering and plant support. The report covers a 7-week period of resident inspection.

Operations

- The inspectors monitored portions of each reactor startup and power ascension and determined that operators manipulated both units in a careful manner in accordance with procedures (Section O1.1).

- Operator identification of increasing Unit 1 unidentified leakage and shut down of Unit 1 was an example of good attention to detail and conservative decision making. The root cause analysis, repairs, and retesting of a leaking threaded joint on Reactor Coolant Pump (RCP) 1-3 were performed well (Section O1.2).

- Overall, Unit 1 operators responded well to two failures of expansion joints. However, operators initially cross-connected intake cooling system trains upon rupture of an expansion joint that could have resulted in loss of both Unit 1 circulating water pumps. Operators recognized and corrected this error before any adverse impact occurred (Section O1.3).

Maintenance

- With the exception of corroded instrument lines associated with the outside tanks, the external condition of plant components observed during tours was good (Section O2.2).

- Routine maintenance and surveillance tasks observed were performed satisfactorily (Sections M1.1 and M1.2).

- The inspectors concluded that vendor information provided to ensure acceptable installation and maintenance of elastomeric expansion joints was not properly implemented into the maintenance program. The licensee's failure to replace expansion joints in a timely manner led to failure of two joints and caused partial flooding of the intake structure and loss of a circulating water pump. These failures required operators to quickly reduce power to preclude a reactor trip. The operability assessment supporting the operability of the safety-related expansion joints failed to reference vendor recommendations on replacement frequency and seismic interactions. As a result, the licensee did not identify an inoperable elastomeric joint, until challenged by the inspector. Further NRC review of the licensee's evaluation of this degraded condition and application of the Maintenance Rule program to expansion joints is required (Section M2.1).

Engineering

- The prompt operability assessment associated with the Unit 1 condensate storage tank leak was an example of good engineering support for operations (Section E2.1).

- The licensee had implemented comprehensive actions in both units to increase tubing stress corrosion resistance and minimize steam generator tube degradation (Section E8.3).

Plant Support

- Housekeeping in the Unit 1 containment building was excellent in that the area near the containment recirculation sumps was clear, the containment building was free of loose work material and debris, and only minor leaks existed in pump and valve packing (Section O2.1).

- A noncited violation of 10 CFR 20.1902(b), consistent with Section VII.B.1 of the Enforcement Policy, was identified for failure to properly post a high radiation area. Radiation protection personnel failed to post a back entrance to Residual Heat Removal Pump Room 1-2. Although the root cause analysis was inconclusive, corrective actions were satisfactory (Section R1.1).

- The inspectors noted that the licensee had inappropriately stored compressed gas cylinders in the auxiliary building. Contrary to plant procedures, personnel had not obtained a transient combustible permit, as required for storing flammable material, which resulted in a violation of Technical Specification 6.8.1.h. The licensee demonstrated that this instance involved low likelihood of a fire involving hydrogen gas. The licensee determined the cause of the violation, identified other examples, and took appropriate corrective actions; therefore, no response was required (Section F1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On December 17, 1998, Unit 1 was shut down because of a weld leak on the component cooling water side of the RCP 1-3 lube oil cooler. Following replacement of the lube oil cooler and resolution of boric acid wastage concerns on RCP 1-3 carbon steel bolts, operators increased Unit 1 power on December 24. Operators synchronized the plant to the grid on December 25 and returned power to 100 percent on December 26. Unit 1 continued to operate at essentially 100 percent power until the end of this inspection period.

Unit 2 began this inspection period at 8 percent power, with power ascension in progress following a forced outage. Unit 2 was synchronized to the grid on December 8 and achieved 100 percent power on December 9. Unit 2 continued to operate 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 backshift inspections. In general, the performance of plant operators reflected a focus on safety, evidenced by self- and peer-checking. The utilization of three-way communications continued to improve, and operator responses to alarms were observed to be prompt and appropriate to the circumstances.

The inspectors monitored portions of each reactor startup and power ascension and determined that operators manipulated both units in a careful manner in accordance with procedures. In addition, on December 17, the inspectors witnessed portions of the Unit 1 reactor shutdown and determined that operators manipulated Unit 1 in a careful manner in accordance with procedures.

O1.2 Shutdown of Unit 1 because of Weld Leak

a. Inspection Scope (92901, 93702)

The inspectors evaluated the response to an increase in unidentified leakage and subsequent reactor shutdown.

b. Observations and Findings

On December 16, 1998, during daily sump calculations, operators detected an increase in unidentified leakage in Unit 1. The unidentified leakage rate had increased from essentially 0 to 0.21 gpm over the previous 24 hours. Because of the high radiation

levels, operators reduced Unit 1 power to 50 percent to allow entry into the RCP 1-3 area. Upon examination, the licensee identified a weld leak on the component cooling water side of the RCP 1-3 upper bearing lube oil cooler.

The licensee replaced the cooler with a spare from the warehouse and performed an operational pressure test to ensure the leakage was corrected. The failure analysis of the weld failure revealed that vibration induced high cycle fatigue caused the failure. The licensee identified that the vibration of the lube oil cooler for RCP 1-3 was significantly higher than the other three Unit 1 RCPs.

On December 18, during routine inspections of the RCP 1-3 work area, a buildup of boric acid on the pump was identified. The licensee determined that the leakage was reactor coolant system pressure boundary leakage from a RCP 1-3 lower radial bearing resistance temperature detector thermowell. Consequently, the licensee cooled down the plant and entered Cold Shutdown on December 19, as required by the Technical Specifications. Mechanics repaired the leak by replacing the threaded resistance temperature detector on December 20.

Following the leak repair, the licensee consulted with the vendor as to the effects of the boric acid on RCP 1-3. The vendor noted previous problems with Westinghouse plants associated with boric acid wastage of the RCP motor stand base bolts. The licensee inspected these bolts on December 20 and noted that 6 of 24 bolts exhibited significant wastage. The licensee examined all of the motor stand bolts associated with RCP 1-3 to determine if further action was required. Based on these inspections, the licensee replaced all of the RCP 1-3 motor stand bolts. No other significant boric acid wastage was identified on the other RCPs. The inspectors visually confirmed that the licensee properly assessed the condition of RCP 1-3.

The licensee determined the root cause of the leak to be incorrect thread engagement of Thermowell TE-168. The inspectors found the root cause assessment satisfactory.

c. Conclusions

Operator identification of increasing Unit 1 unidentified leakage and shut down of Unit 1 was an example of good attention to detail and conservative decision making. The root cause analysis, repairs, and retesting of a leaking threaded joint on RCP 1-3 were performed well.

O1.3 Operator Response to Expansion Joint Failures

a. Inspection Scope (92901, 93702)

The inspectors evaluated operator response to two failures of expansion joints in the intake structure. This inspection included observation of operator response and review of licensee evaluations.

b. Observations and Findings

On December 1, 1998, with Unit 1 at 50 percent power and Unit 2 in Hot Shutdown, an expansion joint failed that partially flooded the intake structure. Approximately 3 feet of water accumulated in the area near the Units 1 and 2 circulating water pumps. This expansion joint was associated with the cross-connect line between the Unit 1 screen wash header and the Unit 2 service cooling system. Upon notification, operators ramped Unit 1 reactor power in a controlled manner to 40 percent, in anticipation of having to secure the operating circulating water pump if the flooding worsened. Once the source of the leak was identified, operators terminated the power decrease and isolated the cross-connect line.

Equipment damage was limited to intake structure sump pumps and light fixtures. The licensee pumped the excess water out of the intake structure and inspected the area for further damage. No safety-related equipment was affected.

The inspectors responded to the control room, witnessed the operator response to this event, and determined that operators carefully manipulated Unit 1 and took prompt action to mitigate the event. In addition, the inspectors examined the flooded areas and concurred with the assessment of the impact of flooding. The root cause of the expansion joint failure is discussed in Section M2.1 of this report.

On December 2, with Unit 1 at 97 percent power, the Unit 1 intake cooling system (which cooled the pump motor windings) expansion joint for Circulating Water Pump 1-2 began leaking. Operators noted that the leakage was minor and intake cooling head tank level could be maintained by the makeup system. As the shift progressed, the leak through this expansion joint worsened, and operators could no longer maintain head tank level. Also, mechanics were unable to affect temporary repairs to mitigate the leak from the expansion joint.

Subsequently, the failure of the expansion joint progressed to the point that a low pressure alarm occurred in the intake cooling system header for Circulating Water Pump 1-2. Because this low pressure condition initiated a timer that automatically trips the circulating pump after 5 minutes, operators decreased Unit 1 power to 50 percent, then secured Circulating Water Pump 1-2.

One of the initial actions had the operators open the two cross-connect valves between the intake cooling headers for Circulating Water Pumps 1-2 and 1-1. This action propagated the expansion joint failure leakage to the other intake cooling system and could have resulted in a similar low pressure condition and subsequent trip of Circulating Water Pump 1-1. Shortly after taking this action, operators recognized the inappropriateness of the action, closed the cross-connect valves between the two intake cooling headers, and isolated the fault. The leakage was contained in the small vault associated with the expansion joint and no other equipment was affected by the presence of the standing water.

Procedure AR PK13-12, "[Circulating Water Pump] CWP 1-2 Cooling Water Low Pressure," Revision 5, provided direction for operator response to a low pressure

condition for the intake cooling header. Step 5.1 of Procedure AR PK13-12 required operators to open cross-connect valves as an initial action to determine if the condition clears. Step 5.3 stated that, if the low pressure alarm does not clear and there is a subsequent low head tank level alarm, suspect a rupture and reclose the cross-connect valves. On December 2, the operators knew that an expansion joint rupture and low intake cooling head tank level condition existed prior to the receipt of the low header pressure alarm, yet took procedural actions contrary to this knowledge.

The inspectors responded to the control room and witnessed operator recovery of the leak. The inspectors concluded that operator response was satisfactory with the exception of initially cross-connecting the intake cooling headers. In addition, the inspectors examined the area of the expansion joint failure and noted that no other equipment was affected. The root cause of failure of the expansion joint is discussed in Section M1.2 of this report.

The Operations Director obtained personnel statements with respect to the operator response. The licensee concurred that operator response was satisfactory with the exception of the initial cross-connecting of the intake cooling system headers. The licensee briefed the shift foreman on thoroughly understanding the consequences of taking actions prior to proceeding. In addition, the licensee stated that they would evaluate the need to enhance Procedure AR PK13-12.

c. Conclusions

Overall, Unit 1 operators responded well to two failures of expansion joints. However, operators initially cross-connected intake cooling system trains upon rupture of an expansion joint that could have resulted in loss of both Unit 1 circulating water pumps. Operators recognized and corrected this error before any adverse impact occurred.

O2 Operational Status of Facilities and Equipment

O2.1 Unit 1 Containment Tour

a. General Comments (71707)

On December 21, 1998, during a forced outage of Unit 1, the inspectors toured the containment to assess readiness for restart. The inspectors noted that the area near the containment recirculation sumps was clear, the containment building was free of loose work material and debris, and only minor pump and valve packing leaks existed. The inspectors concluded that the licensee had satisfactorily restored the Unit 1 containment materiel condition such that the plant was ready for restart.

O2.2 Plant Materiel Condition

a. General Comments (71707)

The inspectors toured both units on a frequent basis to assess the materiel condition of safety-related areas. The inspectors identified minor housekeeping items, such as loose tools and unattended ladders, that were brought to the attention of the shift supervisor and immediately corrected. With the exception of corroded outside tank instrument lines (refer to Section E1.1), the external condition of components observed during plant tours was good.

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 procedures:

- R0187104, "Lubricate [Auxiliary Feedwater] Turbine Over speed Trip Linkages" (Unit 1)
- MP M.3.7A, "Terry Turbine Throttle Trip Valve Preventive Maintenance," Revision 1 (Unit 1)
- R0133000, "MS-1-RV-57 [Auxiliary Feedwater Turbine Casing Relief Valve], Test, Stage, and Replace" (Unit 1)

The inspectors concluded that each of these routine work activities were performed satisfactorily.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed performance of all or portions of the following procedures and reviewed completed data.

- Procedure R-3A, "Use of Flux Mapping Equipment," Revision 0A (Unit 2)
- Procedure STP R-3D, "Routine Monthly Flux Map," Revision 18 (Unit 2)
- Procedure STP R-27A, "Monthly Incore Thermocouple Evaluation," Revision 3 (Unit 2)

- Procedure STP R-13B, "Nuclear Power Range Incore/Excore Single-Point Calibration Data," Revision 2 (Unit 2)

- Procedure STP M-81A, "Diesel Engine Generator Inspection (Every Refueling Outage)," Revision 13 (Unit 1)

b. Observations and Findings

The surveillance tests were satisfactorily performed. For the procedures related to incore/excore detector calibration, the data indicated no abnormal axial offset. For Procedure STP M-81A, the licensee performed an engine analysis on Diesel Engine Generator 1-2. The procedure allowed this analysis to be performed prior to the outage, which is scheduled to start February 7, 1999. The inspectors reviewed the licensee's justification for performing this task on-line and determined that it was satisfactory.

c. Conclusions

The inspectors concluded that surveillances observed during this inspection period were performed satisfactorily.

M2 Maintenance and Materiel Condition of Facilities and Equipment

M2.1 Failure to Implement Vendor Instructions for Elastomeric Expansion Joints

a. Inspection Scope (37551, 62707)

The inspectors reviewed the circumstances surrounding two recent failures of flexible rubber/elastomeric expansion joints. An elastomeric expansion joint was a specially designed section of pipe inserted within a rigid piping system to provide flexibility. The inspectors reviewed action requests (AR) and work packages and interviewed system engineers, maintenance personnel, nondestructive examination personnel, and management. The inspectors observed licensee corrective actions in response to the recent expansion joint failures.

b. Observations and Findings

Two recent expansion joint failures are discussed below:

- On December 1, 1998, as noted in AR A0472252, the screen wash auxiliary header expansion joint failed, resulting in flooding at the intake structure. The expansion joint was 24-inch inside diameter by 12-inch long.

- On December 2, the Circulating Water Pump 1-2 motor cooling inlet-outside housing flexible elastomeric expansion joint (SW-1-EJ21) failed. The expansion joint inside diameter was 6 inches and it was 6 inches long.

b.1 Vendor Information

The inspectors were informed by the system engineers that Uniroyal had provided the original elastomeric expansion joints installed at Diablo Canyon. When Uniroyal stopped manufacturing elastomeric expansion joints, replacement elastomeric expansion joints were obtained from Goodall, RM-Holz Rubber Company, Proco, Uniflex, and Garlock.

The two expansion joints that failed were manufactured in 1972 by Uniroyal and had been installed for approximately 26 years. The replacement expansion joints were manufactured by Garlock.

The inspectors reviewed the equipment specification and vendor documents for the various expansion joints installed. These documents provided detailed expansion joint information related to installation, disassembly, shelf life, and replacement schedule. The documents reviewed included:

- Vendor Manual DC 663323-19-2, "Garlock Expansion Joints, Installation & Maintenance," Revision 4, dated September 1995.
- Vendor Manual DC 663323-11-1, "RM-Holz Technical Handbook - Fifth Edition," Revision 1, dated October 1980.
- Vendor Manual DC 663323-29-1, "How to Install a Garlock Expansion Joint," dated 1995.
- Specification 8725, "Furnishing and Delivery of Elastomeric Expansion Joints for Units 1 and 2 Diablo Canyon Site - Uniroyal Inc.," dated December 22, 1971.
- An April 7, 1994, Garlock supplier (Pacific Mechanical) letter referenced P.O. 42932.

The vendor manuals provided detailed instructions to disassemble the expansion joints, including critical measurements; to install the expansion joints, such as measuring the bolt tightness 1 week after installation and periodically thereafter; and to install control units. Other vendor manual information included the life expectancy of the elastomeric joints. The documents clearly established a life expectancy of 5 years for service conditions that were not severe, which included no misalignment and proper installation and storage. The documents indicated that the elastomeric expansion joints had a 5-year shelf life from the date of manufacture and that the elastomeric joints should be replaced every 5 years. Manual DC 663323-19-2 specifically states, "If no physical/visible signs of distress are present, the expansion joint should be replaced every 5 years. The strength of the expansion joint is in the internal structuring of its layers - deterioration of these strengthening joints is not always apparent." Other information indicated that, although the service life was 5 years, inspections should take place on a yearly basis to check for signs of fatigue or wear.

b.2 Followup on Other Uses of Elastomeric Expansion Joints

System engineers identified approximately 120 elastomeric expansion joints installed in both units and that 13 elastomeric expansion joints were safety-related. On December 8, the inspectors toured various areas of the plant to evaluate elastomeric expansion joint installations in various systems and identified the following:

- Five Uniroyal elastomeric expansion joints had each accumulated approximately 26 years of service. The other elastomeric expansion joints had been in service for 10 years or more.

- A nonsafety-related elastomeric expansion joint on the discharge of Screen Refuse Pump 0-1 was incorrectly installed. Some of the expansion joint flange bolts were installed backwards (the bolt was in contact with the rubber arch section of the joint) and half of the triangular plates of the control units were installed on the wrong side of the expansion joint flanges. The system engineer documented the inspector's observations in AR A0472743 and implemented corrective actions for the installed expansion joint.

- Three as-found elastomeric expansion joints that might have had piping misalignments in excess of the vendor's recommendations for maximum allowable piping misalignment. Two of the expansion joint installations (motor cooling lines for the Unit 1 circulating water pumps) identified with possible piping misalignment problems had similar configurations to the failure of Expansion Joint SW-1-EJ21.

  The inspectors noted that vendors recommended that, whenever excessive piping misalignment existed prior to installing an expansion joint, either the piping had to be realigned or a special offset expansion joint had to be supplied by the vendor. The inspectors noted that acceptable piping alignment is critical to ensure elastomeric expansion joints have freedom of movement within specified design limits. The system engineer informed the inspectors that engineering personnel were reviewing all existing elastomeric expansion joint installations as part of the corrective actions implemented for the expansion joint failures.

- After replacing failed Expansion Joint SW-0-EJ2, the flange on the east side of the expansion joint had a crack, which leaked approximately 10 gallons per hour. The crack extended from the edge of a flange bolt hole into the flange neck area. The licensee documented this deficiency in AR A0472629. The licensee determined that the leak resulted from a flaw in the flange, not from maintenance activities.

b.3 Generic Letter 89-13 Commitments

The inspectors reviewed the licensee's November 25, 1991, response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The licensee had established a routine inspection and maintenance program to ensure that auxiliary saltwater system performance was not adversely impaired. The inspectors

reviewed AR A0043296 and noted that it identified 13 safety-related expansion joints that were to be inspected every 24 months to satisfy the commitment to Generic Letter 89-13. These expansion joint inspections were performed in accordance with various recurring task activity work orders under the preventive maintenance program. During these inspections engineering personnel performed a visual inspection of expansion joints for cracks, bulges, leaks, or visible indications of past leakage. The inspectors concluded that the licensee's actions met the Generic Letter 89-13 commitments with respect to elastomeric joints.

b.4 Preventive Maintenance Program Adequacy for Elastomeric Joints

At the completion of the inspection, the licensee had not determined whether the initial two failures were maintenance preventable functional failures or completed their plans for upgrading the preventive maintenance program.

The inspectors reviewed various vendor documents supplied to the licensee, work orders, ARs, and expansion joint installations and, after conducting discussions with maintenance and system engineering personnel, the inspectors noted that as of January 6, 1999:

- Approximately 10 of the 13 safety-related elastomeric expansion joints currently installed in the plant had been manufactured by Garlock, and some of these expansion joints had been in service in excess of 5 years.

- While Garlock vendor information identified that the typical service life expectancy of an elastomeric expansion joint was 5 years and that preventive maintenance schedules should be enacted accordingly, the licensee had not implemented this information into the applicable maintenance programs or schedules or provided the technical basis for not accomplishing this recommendation.

- Engineering personnel had not identified the service life expectancy for the various other nonsafety-related elastomeric expansion joints currently installed in the plant.

- The inspectors determined that existing maintenance procedures and work documents did not include various vendor recommendations for elastomeric expansion joint installations, which included: (1) Retighten the expansion joint flange bolts after 7 days of system operation; (2) recheck bolts for tightness periodically, or every 6 months, after placing the system into service; and (3) check bolts for tightness after any extended system outage.

- Vendor documentation also stated that, prior to replacing an existing expansion joint, dimensions must be verified. As a result of settlement, misalignment, or improper design, many elastomeric expansion joints may be overstressed beyond their performance limitations. It is critical, therefore, that all measurements (overall flange-to-flange, lateral, torsional, and angular misalignment) be checked against original specifications/drawings.

The inspectors noted that these measurements were not documented for the replacement of the two failed joints and, based on a sample review, had not been documented during replacement of other expansion joints over the last 2 years.

Engineering personnel implemented actions to have vendor representatives (Garlock) perform onsite evaluations of the condition of all installed expansion joints and perform onsite elastomeric expansion joint training for plant personnel the week of January 11. The vendor representatives informed the inspectors that they would be providing the licensee with a trip report and recommended actions. The licensee representatives stated that they would evaluate the vendor information for any needed changes in their maintenance program. The licensee representatives also stated that the vendor identified two other nonsafety-related expansion joints that showed indications of potential failure. The licensee initiated actions to replace these expansion joints.

b.5 Operability Assessment of Safety-Related Expansion Joints

During review of the safety-related expansion joints, the licensee identified three expansion joints in the auxiliary saltwater system that had been in service longer than 15 years. The licensee determined that two expansion joints had been installed for 15 years and that one expansion joint had been installed for over 26 years (same manufacturer and age as the failed expansion joints). The licensee concluded by engineering judgement that these expansion joints remained acceptable for use until the Unit 2 outage in September 1999. The licensee based this decision on: (1) external visual inspections of all three expansion joints; (2) internal inspections of the oldest Uniroyal expansion joint; and (3) an analysis that indicated that these joints, located at the high point in the system, were subject to very little differential pressure.

Because the licensee had not thoroughly consulted the vendor manual with respect to expansion joints, the licensee wrote a prompt operability assessment in AR A0472506 that had questionable reasoning. The assessment stated that the expansion joints had only slightly exceeded their service life of 15 years, even though the vendor manual recommended replacement every 5 years. In addition, the assessment stated that external visual inspections were satisfactory. However, the vendor manual indicated that external inspections did not provide useful information because the integrity of the expansion joint was based on the material condition of the internals. The licensee correctly noted that the aging expansion joints in the auxiliary saltwater system were subjected to pressures substantially less than the design pressure (3 versus 100 psig).

The inspectors visually inspected the external surface of the three older auxiliary saltwater expansion joints and did not note any damage. In addition, the inspectors inspected the internal surface of the 26-year old expansion joint during routine component cooling water heat exchanger cleaning and did not note any degradation. However, the inspectors noted that Garlock technical information indicated that visual inspections did not always indicate impending failure. In addition, the inspectors determined that the licensee had not yet addressed the potential common-mode failure of both Unit 2 component cooling water heat exchangers because of age hardening failure of the auxiliary saltwater expansion joints during a seismic event.

Subsequently, the licensee calculated the magnitude of the displacement of the safety-related expansion joints during a seismic event. Calculations revealed that total displacement (including thermal expansion) of the Component Cooling Water Heat Exchanger 2-1 inlet expansion joint was approximately 0.75 inches. The licensee contacted the vendor with this information. The vendor representative stated that operability of this expansion joint could not be assured given the age-related hardening and maximum displacement. On January 28, 1999, the licensee declared Expansion Joint SW-2-EJ3 inoperable and replaced it immediately. The vendor evaluated the other two questionable auxiliary saltwater expansion joints and determined that they would remain operable because of considerably less displacement during a seismic event.

The inspectors concluded that the licensee's operability determination of the oldest safety-related expansion joints was weak, because it failed to accurately reference vendor recommendations on replacement frequency and had not considered seismic interactions. Further NRC review of compliance with 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (Maintenance Rule) in regard to expansion joints is required, pending completion of the licensee's maintenance preventable functional failure evaluation. This issue is unresolved (50-275; 323/98020-01).

c. Conclusions

The inspectors concluded that vendor information provided to ensure acceptable installation and maintenance of elastomeric expansion joints was not properly implemented into the maintenance program. The licensee's failure to replace expansion joints in a timely manner led to failure of two joints and caused partial flooding of the intake structure and loss of a circulating water pump. These failures required operators to quickly reduce power to preclude a reactor trip. The assessment that supported the operability of the safety-related expansion joints failed to reference vendor recommendations on replacement frequency and seismic interactions. As a result, the licensee did not identify an inoperable elastomeric joint, until challenged by the inspector. Further NRC review of the licensee's evaluation of this degraded condition and application of the Maintenance Rule program to expansion joints is required.

M8 Miscellaneous Maintenance Issues (92903)

M8.1 (Closed) Violation 50-275; 323/96021-04: failure to establish appropriate performance criteria for the main steam safety valves (MSSVs)

This violation reported that the licensee had set system level performance criteria for the MSSVs at too high a threshold to provide a true indication of component reliability. Although a number of MSSVs had failed to meet the Technical Specification criteria, the licensee had not considered any of these failures to be maintenance preventable functional failures.

As corrective action, the licensee also performed an audit of Maintenance Rule compliance and found other program deficiencies. However, the licensee did not

resolve these program deficiencies in a timely manner, which resulted in Violation 50-275; 323/97004-01 as documented in the NRC Maintenance Rule baseline inspection. Because the programmatic corrective actions were subject to review during the Maintenance Rule baseline inspection, the inspectors reviewed the corrective actions specifically associated with the MSSVs.

The inspectors determined that the Maintenance Rule program included specific performance criteria for the MSSVs, including meeting the Technical Specifications requirements. The inspectors reviewed recent MSSV testing and determined that most valves had met the Technical Specifications criteria during the most recent testing even though the MSSVs were still in 10 CFR 50.65 (a) (1), goal setting. The inspectors also determined that recent individual failures to meet the Technical Specifications criteria were properly considered to be maintenance preventable functional failures and that the testing program included performance of additional testing, if any one valve failed to meet the Technical Specifications criteria.

M8.2 (Closed) Violation 50-275; 323/96023-02: failure to take corrective action to preclude failure of first level undervoltage relay to meet Technical Specification requirements.

This violation resulted because 8 of 18 surveillance tests of first level undervoltage relays had failed to meet Technical Specifications requirements. They had not determined the root cause or taken actions to preclude recurrence. The licensee later determined that many of these failures resulted from personnel error in setting the relays different than recommended by the manufacturer.

During observations of secondary level undervoltage relay testing, discussed in NRC Inspection Report 50-275; 323/98-16, the inspectors reviewed recent first level undervoltage relay data and determined that the performance had improved. In addition, the licensee had submitted Licensee Amendment Request 98-08 to obtain NRC approval to change the specific model of the relay and slightly modify the relay setpoints. The inspectors considered that the licensee corrective actions to resolve this violation were appropriate.

M8.3 (Closed) Violation 50-323/96023-03: failure to properly restore a temporary modification.

The inspectors identified that, following removal of a temporary pressure gage from the Unit 2 chemical and volume control system, maintenance personnel failed to remove the jumper tag and correct the control room drawings, which violated procedures.

For corrective actions the licensee: (1) removed the information tag; (2) corrected the control room drawing; (3) discussed the violation with the personnel involved and provided shift orders to the operating crews to emphasize operator responsibilities with respect to lifted leads and jumpers; (4) revised Procedure CF4.ID7, "Temporary Modifications - Plant Jumpers and M&TE" to provide added tracking mechanisms for closure of lifted lead and jumper entries; and (5) performed a review of the jumper logs to ensure that no other discrepancies existed.

The inspectors reviewed licensee documentation that demonstrated that these items were completed and concluded that the documentation was satisfactory.

M8.4 (Closed) Licensee Event Report 50-275; 323/96-018-01: 4kV bus undervoltage protection relays out of specification because of personnel error.

This LER revision is closed as discussed in Section M8.2.

III. Engineering

E1 Conduct of Engineering

E1.1 Condensate Storage Tank (CST) Leakage

a. Inspection Scope (37551)

The inspectors evaluated the engineering response to leakage from the Unit 1 CST, in accordance with AR A0474556.

b. Observations and Findings

On January 11, 1999, the licensee noted water leaking from the area of the Unit 1 CST. Inspection revealed that the leak was from a 1-inch instrument line for Level Transmitter LT-40 that penetrated the side wall near the bottom of the CST. Level Transmitter LT-40 provided level indication at the hot shutdown panel for the CST. This carbon steel line had corroded because of rainwater seepage into the area, resulting in the through-wall leak. The licensee declared Level Transmitter LT-40 inoperable and initiated an AR to enter this item into the corrective action program.

Because of the through-wall leak, the licensee determined that the seismic qualifications of the instrument line could not be justified. Consequently, the licensee postulated a complete failure of the instrument line and initiated a prompt operability assessment. The licensee evaluated whether the CST had adequate capacity to support auxiliary feedwater operation for the required 8 hours in hot shutdown, with the additional water loss from the 1-inch instrument line break and assumed that the CST was 83 percent full. The licensee used guillotine breaks of the single 12-inch and four 4-inch Class 2 lines and calculated the amount of time it took for the CST to drain below these penetrations. Using this methodology, the licensee determined that the CST remained operable. The inspectors reviewed the licensee calculations and agreed with the conclusions.

For a temporary repair, divers entered the CST and installed an expandable plug in the affected penetration for the instrument line. Technical Specifications require Level Transmitter LT-40 to be returned to service within 30 days or place the unit in hot shutdown. However, since this leak was discovered 26 days before Refueling Outage 1R9, the licensee delayed the permanent repair of the instrument until the outage.

The inspectors questioned the generic implications of this issue. The Unit 1 CST had two other safety-related instrument lines. The licensee inspected these lines and noted some degradation of the wall thickness but no through-wall leakage. In addition, the licensee inspected similar penetrations on Unit 2 and identified no additional concerns. The inspectors also examined these areas and concurred with the conclusions. The licensee stated that they had also planned to inspect the penetrations associated with the other outside storage tanks (refueling water storage tanks, primary water storage tanks, and fire water storage tank). The inspectors considered the scope of the inspections satisfactory.

The inspectors questioned the licensee as to why the maintenance rule program for periodically examining safety-related structures had not identified this issue. The licensee stated that the outside tanks and associated penetrations were in the scope of the inspections but had not yet been scheduled. The inspectors will perform further review of the adequacy of the maintenance rule program for assessing structures. This issue will be tracked as an inspection followup item (50-275; 323/98020-02).

c. Conclusions

The prompt operability assessment associated with the Unit 1 CST leak was an example of good engineering support for operations. Review of the adequacy of the maintenance rule program to assess safety-related structures required further review.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Licensee Event Report 50-275; 323/96-014-00: Steam Generator primary coolant tubes were locked in tube support plates.

This licensee event report is administratively closed based on issuance of Revision 1.

E8.2 (Closed) Violation 50-275; 323/96024-02: Design criteria memoranda revised without proper evaluation.

The inspectors identified that Design Criteria Memorandum S-9, "Safety Injection System," was revised without evaluating the changes in accordance with Procedure CF3.ID2, "Design Criteria Memoranda," Revision 2, which required changes to the design criteria memoranda to be evaluated for impact on the plant licensing basis.

For corrective actions the licensee: (1) incorporated the proper calculation into Design Criteria Memorandum S-9, (2) discussed the improper changes with the personnel involved, (3) performed a separate calculation to verify that the proper amount of water existed in the refueling water stowage tank, and (4) performed additional reviews of other design criteria memoranda.

The inspectors performed a review of documentation supporting completion of the corrective actions and concluded that the licensee actions were satisfactory.

E8.3 (Closed) Licensee Event Reports 50-275/97-007-00 and 50-323/98-002-00: greater than 1 percent steam generator tubes defective.

In accordance with Technical Specification 4.4.5.5c, the licensee reported that greater than 1 percent of the tubes inspected in Steam Generators 1-1 and 1-2 during Refueling Outage 1R8 and Steam Generator 2-2 during Refueling Outage 2R8 were defective.

The inspectors ascertained from review of the Refueling Outage 1R8 examination history that the number of tubes found to contain defects in Steam Generators 1-1, 1-2, 1-3, and 1-4 were, respectively, 46, 125, 10, and 18. All defective tubes were removed from service by plugging. The defective tube totals for Steam Generators 1-1 and 1-2 represented, respectively, 1.36 percent and 3.69 percent of the 3388 tube population in an individual steam generator. The most significant tube degradation mechanism was primary water stress corrosion cracking at hot-leg side dented tube support plate intersections, which resulted in a total of 128 tubes being removed from service in the four steam generators. The second greatest detected tube degradation mechanism was outside diameter stress corrosion cracking at nondented tube support intersections, which resulted in the removal of 45 tubes from service in the four steam generators.

Actions taken by the licensee to increase tubing stress corrosion resistance and minimize steam generator tube degradation were reviewed during a 1995 steam generator tube integrity inspection (NRC Inspection Report 50-275; 323/95-10). Specific initiatives implemented by the licensee included the following:

- Thermal stress relief of Rows 1 and 2 low radius U-bends to minimize the tubing susceptibility to primary water stress corrosion cracking; implement boric acid additions to the secondary side to arrest tube denting and limit initiation of outside diameter stress corrosion cracking; and replace copper alloy tubes in the feedwater heaters with stainless steel, in order to eliminate copper transport to the steam generators and minimize its contribution to development of outside diameter stress corrosion cracking and pitting in the steam generator tubes;

- Shot peening the inside diameter surface of the tubes in the tube sheet region to minimize development of primary water stress corrosion cracking at this tubing location;

- Adopting Electric Power Research Institute secondary water chemistry recommendations to increase hydrazine additions to 100 parts per billion, in order to reduce electrochemical potential in the steam generators and thereby minimize development of outside diameter stress corrosion cracking;

- Initiating the use of ethanolamine (for pH control) to reduce iron transport to the steam generators, which minimizes its contribution to development of outside diameter stress corrosion cracking;

- Adopting Electric Power Research Institute secondary water chemistry recommendations for use of molar ratio control (using ammonium chloride

injection), as a means of eliminating alkaline crevice chemistry conditions that promote initiation of outside diameter stress corrosion cracking;

- Using eddy current examination practices that are consistent with the latest guidance contained in Electric Power Research Institute Document "PWR Steam Generator Examination Guidelines" and the WEXTEX owners group guidelines;

- Adopting a policy of maintaining steam generator blowdown at 1 percent of the main steaming rate, in order to minimize steam generator contaminate levels.

In June 1998, the licensee initiated injection of zinc acetate into the Unit 1 reactor coolant system to maintain a zinc concentration of 35-40 ppb. Ionic zinc has been found by laboratory testing and analytical programs to reduce general corrosion of primary system materials and to partially inhibit primary water stress corrosion cracking of Inconel 600.

The inspectors ascertained from review of the Refueling Outage 2R8 examination history that the number of tubes found by eddy current examination to contain defects in Steam Generators 2-1, 2-2, 2-3, and 2-4 were, respectively, 8, 34, 26, and 23. All of the defective tubes were plugged. These totals reflected the initial use by the licensee of voltage-based alternate repair criteria for outside diameter stress corrosion cracking at tube support plates. Use of the voltage-based alternate repair criteria for Unit 2 steam generators was approved by the issuance of License Amendment 122. Without the voltage-based alternate repair criteria, the respective plugging totals for Steam Generators 2-1, 2-2, 2-3, and 2-4 would have been 29, 48, 33, and 99 tubes. Accordingly, the use of voltage-based alternate repair criteria made only Steam Generator 2-2 reportable in accordance with Technical Specification 4.4.5.5c, with slightly over 1 percent of the tubes being plugged.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Inadequate High Radiation Area Posting

a. Inspection Scope (71750)

The inspectors evaluated the licensee's response to AR A0473925, which described an inadequate high radiation posting.

b. Observations and Findings

On December 23, 1998, during a routine radiation protection tour of the facility, radiation protection personnel identified that the Residual Heat Removal Pump Room 1-2 recirculation chamber door was posted as a radiation area while the main double-door entry into the room was posted as a high radiation area. Radiation protection personnel corrected this posting error immediately and initiated an AR. A high radiation area sign and yellow and magenta rope were found staged near the improper posting.

Licensee investigation revealed that, on December 18, high radiation area signs and rope were staged at all entrances to both Unit 1 residual heat removal rooms. This was done in anticipation of initiating the residual heat removal system to cool down the plant for repairs of a primary pressure boundary leak. On December 20, radiation protection technicians performed surveys that established that the residual heat removal pump rooms required upgrading to high radiation area postings. A radiation protection technician stated that he properly posted each room at this time. No other surveys of the room were performed subsequently, and no other personnel in the area could recall the area being reposted as a radiation area. Therefore, the licensee concluded that the root cause was indeterminate.

Although the licensee did not identify a definitive root cause, the licensee recommended several corrective actions. Corrective actions included: (1) properly posting Residual Heat Removal Pump Room 1-2, (2) initiating an expectation that changes in postings be documented on the survey forms and that personnel reviewing surveys check the postings, (3) recommending that radiation protection foremen walk down areas that have changes to postings, and (4) discussing this event with all radiation protection technicians and foremen. The inspectors considered the corrective actions to be satisfactory.

Failure to properly post an area containing radiation doses in excess of 100 millirem per hour as a high radiation area is a violation of 10 CFR 20.1902(b). However, this nonrepetitive, licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.I of the Enforcement Policy (50-275; 323/98020-03).

c. Conclusions

A noncited violation of 10 CFR 20.1902(b), consistent with Section VII.B.I of the Enforcement Policy, was identified for failure to properly post a high radiation area. Radiation protection personnel failed to post a back entrance to Residual Heat Removal Pump Room 1-2. Although the root cause analysis was inconclusive, corrective actions were satisfactory.

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 backshift inspections, the inspectors noted that the protected area was properly illuminated, especially in areas where temporary equipment was brought in.

F1 Control of Fire Protection Activities

F1.1 Control of Combustibles (Units 1 and 2)

a. Inspection Scope (71750)

The inspectors toured safety-related areas to ensure that licensee procedures concerning the control of combustibles were implemented.

b. Observations and Findings

On October 20, 1998, the inspectors identified that 2 hydrogen compressed gas cylinders were located on the 85-foot elevation of the auxiliary building. These cylinders were sized to contain 7.1 cubic feet of 10 percent hydrogen at 2200 psig. The inspectors expressed concern because hydrogen is flammable. Further, the fire protection program required a permit to bring combustible materials into vital areas, including the power block. Subsequently, the licensee removed the cylinders from the power block and initiated AR A0470209 to enter this item into the corrective action program. On October 29, the licensee performed walkdowns of both units and noted 5 other compressed gas cylinders of similar size that were improperly stored, and which contained flammable gasses. These items were also removed from the power block.

Licensee investigation revealed that maintenance personnel had brought these compressed gas cylinders into these vital areas. Compressed gas cylinders containing argon were approved for use in the power block on the 85-foot elevation of the auxiliary building in accordance with Design Change Notice DCN-EM-39613. Personnel believed that this document allowed compressed gas cylinders in the area without regard to content. This misconception was discussed with maintenance personnel because the design change did not exempt the licensee from fire protection requirements. The licensee evaluation further revealed that this issue was of low potential safety significance. Although hydrogen, a flammable gas, was introduced into areas containing safety-related equipment, a scenario involving a fire associated with the hydrogen gas was considered unlikely. In addition, the licensee performed calculations that revealed that, because of the size of the space, if all of the gas was released to the 85 foot elevation, a combustible mixture would not result.

Procedure OM8.ID4, "Control of Flammable and Combustible Materials," Revision 7, Section 4.2.3, required issuance of a transient combustible permit when flammable materials were brought into the power block. Therefore, the introduction of compressed gas cylinders containing hydrogen without a transient combustible permit is a violation of Technical Specification 6.8.1.h. However, because the licensee took satisfactory corrective actions in AR A0470209 in response to this issue, no response was required (50-275; 323/98020-04).

c. Conclusions

The inspectors noted that the licensee had inappropriately stored compressed gas cylinders in the auxiliary building. Contrary to plant procedures, personnel had not obtained a transient combustible permit, as required for storing flammable material, which resulted in a violation of Technical Specification 6.8.1.h. The licensee demonstrated that this instance involved low likelihood of a fire involving hydrogen gas. The licensee determined the cause of the violation, identified other examples, and took appropriate corrective actions; therefore, no response was required.

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 January 30, 1998. 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, Maintenance 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
J. E. Molden, Manager, Operations Services
D. H. Oatley, Vice President and Plant Manager
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 92903	Followup - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

50-275; 323/ 98020-01	URI	Evaluate adequacy of maintenance rule program for expansion joints (Section M2.1)
50-275;323/ 98020-02	IFI	Evaluate adequacy of maintenance rule monitoring of outside tanks (Section E1.1)

Closed

50-275; 323/ 96021-04	VIO	Failure to establish appropriate performance criteria for MSSVs (Section M8.1)
50-275; 323/ 96023-02	VIO	Failure to take corrective actions to preclude first level undervoltage relay failures to meet Technical Specifications requirements (Section M8.2)
50-275; 323/ 96023-03	VIO	Failure to restore a temporary modification (Section M8.3)
50-275; 323/ 96-018-01	LER	4kV bus undervoltage protection relays out of specification because of personnel error (Section M8.4)
50-275; 323/ 96024-02	VIO	Design criteria memoranda revised without proper evaluation (Section E8.1)
50-275; 323/ 96-014-00	LER	Steam generator primary coolant tubes were locked in tube support plates (Section E8.2)
50-275/97-007-00	LER	Greater than 1 percent steam generator tubes defective (Section E8.3)
50-323/98-002-00	LER	Greater than 1 percent steam generator tubes defective (Section E8.3)

Opened and Closed

50-275; 323/ 98020-03	NCV	Failure to properly post a high radiation area (Section R1.1)
50-275; 323/ 98020-04	VIO	Failure to obtain transient combustible permit for compressed gas cylinders containing hydrogen (Section F1.1)

LIST OF LICENSEE DOCUMENTS REVIEWED

Procedure

MA1.ID17 "Maintenance Rule Monitoring Program," Revision 5

Specification

8725 "Furnishing and Delivery of Elastomeric Expansion Joints for Units 1 and 2 Diablo Canyon Site - Uniroyal Inc,," dated December 22, 1971

Vendor Manuals

DC 663323-10-2	"Expansion Joints and Vibration Dampeners Installation Instructions Unit One &Two," Revision 2
DC 663323-11-1	"RM-Holz Technical Handbook - Fifth Edition", Revision 1
DC 663323-19-2	"Garlock Expansion Joints, Installation & Maintenance," Revision 4
DC 663323-29-1	"How to Install a Garlock Expansion Joint," dated 1995

Action Requests

A0043296
A0336216
A0472252
A0472458
A0472506
A0472629
A0472743

Quality Evaluation

A0472288

Nonconformance Report

N0002079

Work Orders

C0140103
C0143142
C0159711
C0159751
R0078760
R0078800
R0165894
R0165917

LIST OF ACRONYMS USED

AR	Action Request
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
CWP	Circulating Water Pump
IP	Inspection Procedure
LER	licensee event report
MSSV	Main Steam Safety Valve
NCV	Noncited Violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
RCP	Reactor Coolant Pump
STP	Surveillance Test Procedure
URI	Unresolved Item
VIO	Violation